**DRAFT** White Paper Addressing Differences Between the
CDR Report and Transmission Planning Models

Overview

During the July 10, 2014, meeting of the ERCOT Reliability and Operations Subcommittee (ROS), the Planning Working Group (PLWG) was asked to create a white paper describing the load and generation assumption methodologies utilized in the Report on the Capacity, Demand and Reserves in the ERCOT Region (CDR Report) and the various ERCOT transmission planning models (Transmission Planning Models). This white paper seeks to satisfy that request by:

* describing the purposes of the CDR Report and the Transmission Planning Models;
* identifying the assumption methodologies used in the CDR Report and Transmission Planning Models;
* explaining the reasons why different assumption methodologies may be appropriate for certain assumptions; and
* identifying the assumptions for which it may be appropriate to eliminate the differences.

The CDR Report provides an estimate of the planning reserve margin in the summer and winter peak load seasons for the next ten years.[[1]](#footnote-1) At a high level, the planning reserve margin is calculated as the difference between generation capacity and firm peak load. This calculation does not itself provide information about expected reliability in future years because it does not fully account for forced generation outages, extreme temperatures, and the variability of wind and other renewable resources. To address those issues, a separate loss-of-load expectation study (LOLE Study) is performed to determine the expected level of reliability provided by a given planning reserve margin. Stakeholders may then compare the expected planning reserve margins in the CDR Report with the results of the LOLE Study to inform their respective activities related to the ERCOT Region.

The Transmission Planning Models provide information about whether electric grid infrastructure will be adequate to move electric power from generation resources to customers under a variety of possible future conditions. The Transmission Planning Models include expectations about three categories of electric grid components: the location and capacity of future resources (i.e., generation), a forecast of the customer demand by substation that will need to be served (i.e., load), and the specifications of the expected individual components that make up the transmission grid (i.e. system topology). The processes used to develop the Transmission Planning Models are defined in the Steady-State Working Group Procedure Manual, the ERCOT Protocols, and the ERCOT Planning Guide. The Transmission Planning Models are also developed in compliance with the reliability standards issued by the North American Electric Reliability Corporation (NERC). These models do not themselves provide information about expected future transmission reliability but rather are a starting point for transmission reliability studies performed by ERCOT and stakeholders using specialized power flow software.

Because the CDR Report and the Transmission Planning Models both include assumptions about future resources and loads, it is expected that the assumptions should be generally consistent, and to the extent they are different, the reasons for those differences should be known. The following table describes the generation and load assumption used in the CDR Report and Transmission Planning Models.

Comparisons of CDR Report and Transmission Planning Models

|  |  |  |
| --- | --- | --- |
|  | **CDR Report** | **Transmission Planning Models** |
| **SSWG Cases** | **RTP Reliability Cases** | **RTP Economic Cases** |
| **Purpose** | Provide an accounting of all resource types, including generation resources, load resources, ERS, DC ties, available mothballed capacity, switchable capacity, TDSP load management programs, etc., available at hour of peak system demand.  | Provide a range of power flow cases with a common reference point for ERCOT and Market Participants. | Provide power flow cases for use in developing the reliability portion of the ERCOT Regional Transmission Plan | Provide a power flow case for use in developing the economic assessment portion of the ERCOT Regional Transmission Plan |
| **Load Forecast Inputs** |  |  |  |  |
| **Preparer** | ERCOT | TSPs | ERCOT and TSPs | ERCOT |
| **Season** | Summer and Winter | * Four seasons for current year
* Summer peak for next 6 years
* Minimum load and high wind for a future year
 | Summer peak for future Years 1, 3, 5, and 6 | Full year hourly analysis for Future Years 3 and 6 |
| **Weather Assumptions** | Average weather(expect actual load to exceed forecast one out of two years) | Varies by TSP | Higher of:* Summed TSP forecasts in each weather zone; or
* ERCOT 90th percentile extreme weather forecast by weather zone (expect actual load to exceed forecast one out of ten years)
 | Average weather in each weather zone (expect actual load to exceed forecast one out of two years) |
| **Load Coincidence** | Coincident(single peak load hour for ERCOT Region) | Peak load by individual substation (non-coincident) | Peak load by individual substation for each weather zone (non-coincident), with exceptions made depending on the case. | Hourly 50/50 (average weather) coincident load forecast developed by weather zone |
| **Load Resource and other Demand Response Programs** | Included(shown as separate line item) | Not Included | Not included | Not Included |
| **Self-Serve Load** | Net to the grid(self-serve load minus self-serve generation) | Gross(no reduction for self-serve generation) | Gross(no reduction for self-serve generation) | Gross(no reduction for self-serve generation) |
| **Load Adjustments** | None | As needed on a case-by-case basis | Adjustments made outside of study region by weather zone | None |
| **Generation Inputs** |  |  |  |  |
| **Wind Generation** | Capacity contribution based on average of recent peak-season output (top 20 load hours) | 100% of capacity modeled. Units dispatched as per Appendix B of SSWG manual, Methodology for Calculating Wind Generation in the SSWG Cases, unless total load and reserve requirements are greater than available generation, then use Extraordinary Dispatch procedures, Section 4.3.3.1 of SSWG manual.  | 100% of capacity modeled. Units dispatched at varying levels, depending on the case | Units dispatched based on representative hourly patterns appropriate for weather assumptions |
| **Solar Generation** | Output levels based on average of recent peak-season output (top 20 load hours) | 100% of capacity modeled. Units dispatched based on review of historic seasonal output | 100% of capacity modeled. Units dispatched at 15th percentile output when load is at 90th percentile or higher; using AWS TruePower profiles[This does not look correct for solar output. Solar should be higher than 15th percentile output] | Units dispatched based on representative hourly patterns appropriate for weather assumptions; using AWS TruePower profiles |
| **DC-Ties** | Output levels based on average of recent peak-season output (top 20 load hours) | 100% of capacity modeled. Units dispatched based on review of historic seasonal operating levels | 100% of capacity modeled. Units dispatched based on review of historic seasonal operating levels | Units dispatched based on historical hourly patterns |
| **Hydro Generation** | Output levels based on average of recent peak-season output (top 20 load hours) |  Units modeled offline |  Units modeled offline | Units dispatched based on historical hourly patterns |
| **Requirements for Including Planned Generation** | * Signed interconnection agreement;
* Air permits (if needed); and
* Cooling water attestation
 |  | * Signed interconnection agreement;
* Air permits (if needed);
* Cooling water attestation; and
* Full financial commitment and notice to proceed given to TSP
 | * Signed interconnection agreement;
* Air permits (if needed);
* Cooling water attestation; and
* Full financial commitment and notice to proceed given to TSP
 |
| **Self-Serve Generation** | Net to grid during peak hours of recent peak season  | Full capacity available | Full capacity available | Full capacity available |
| **Switchable Units** | Capacity contracted to other region is not included | Capacity contracted to other region is considered unavailable | Capacity contracted to other region is considered unavailable | Capacity contracted to other region is considered unavailable |
| **Mothball Generation** | Capacity is included if unit owner states likelihood of return is greater than 50% | Capacity available if needed to allow model to solve as per Section 4.3.3.1 of SSWG manual, Extraordinary Dispatch procedures. | Mothball units not available[Discuss: previous RTP scopes have stated: “If needed to meet the load and reserve requirements, mothballed units will be placed in-service in the reliability analysis per the SSWG Procedure Manual Section 4.3.4.” | Mothball units not available |

CDR Report

The CDR Report is an accounting of expected loads and resources that provides a forecast of future year planning reserve margins. The analysis that allows the CDR Report to be informative is built into the LOLE Study that is used to determine the expected level of reliability provided by a given planning reserve margin.

In order for this comparison between the results of the CDR Report and LOLE Study to be meaningful, the assumptions used to develop the CDR Report must be consistent with those used in the LOLE Study. These assumptions include the assumed capacity contribution of variable resources such as wind and solar generation and the specific weather conditions used to develop the load forecast.[Discuss: not sure what is meant by these statements. The CDR assumptions are fairly stagnant, while the LOLE assumptions are by design variable.] While ERCOT currently uses average weather conditions to develop the load forecast in the CDR, this and other input assumptions can be varied without reducing the validity of the CDR Report as long as similar changes are made to the input assumptions included in the corresponding LOLE Study. Similarly, the full impact of resource outages, both planned and unplanned, on system reliability is included in the development of the LOLE Study. As such, the analysis in the CDR Report does not include any deration of available resources to reflect possible outages.

A LOLE Study includes multiple scenarios based on a range of possible weather conditions. Derived from historical weather patterns, these load scenarios are consistent with weather expectations ranging from mild to extreme, with appropriate probabilities of occurrence assigned to each weather scenario. Similarly, resource outages are included in the study based on historical operational data reflecting by unit maintenance schedules and forced outage probabilities. Variable generation units, such as wind, solar and hydro generation, are included in the study as hourly output based on weather patterns that are consistent with the load used for each specific scenario. In this way the net impact of weather on both load and variable generation is consistent with actual historical data.

Resource information in the CDR Report is derived from the Resource Asset Registration forms (RARFs) submitted by resource owners. Additional information regarding the expected output of renewable generation, the net output of self-serve generation (behind the fence), and the net import from DC-ties is calculated from operational data.[What about the other outputs? ERS, LaaRs, TDSP programs, etc.?] As the CDR Report consists of a simple accounting of resources and loads, with all input assumptions listed in Section 3.2.6 of the Protocols, stakeholders can adjust the calculations and results to reflect their own different assumptions. In this way, the specific assumptions in the CDR Report are less important than those in the Transmission Planning Models.[What is meant by this sentence? Is this someone’s opinion? PLWG should strive to keep this whitepaper factual without individual viewpoints.] The analysis conducted in the transmission planning process cannot be adjusted by stakeholders after completion to reflect different input assumptions.[Is this a true statement. If it is, why are stakeholders precluded from running their own transmission planning scenario analysis ?]

[This whole paragraph makes an assumption that transmission can solve a resource adequacy issue. What if there isn’t enough excess generation outside the load pocket to transport across the transmission lines to serve the load? You still have a resource adequacy issue that isn’t fixed by wire. The last sentence could have easily been stated as “Insufficient generation serving one or more locations in ERCOT will create a load pocket in which outage expectations are higher than the system as a whole. This same reliability issue can also occur if there isn’t excess generation outside a load pocket to transport to the load pocket.” I think we should say the CDR does not account for transmission, and many previous GATF meetings have debated whether or not the assumption of complete deliverability is reasonable for the CDR.

Transmission Planning Models

There are numerous future year Transmission Planning Models used by ERCOT and the Transmission Service Providers (TSPs) to assess transmission adequacy and reliability. ERCOT, the TSPs, along with many other involved stakeholders who submit model data representing their grid-connected equipment, develop sixteen steady-state planning cases representing the current and future years, three transient stability cases and a short-circuit case. The intent of all of these models is to allow planners to assess the capability of the transmission infrastructure to move power reliably from existing and planned resources to every load-serving substation in the system under reasonably likely future system conditions. Each of these models includes input assumptions, such as the customer demand levels assigned by bus (e.g., a load forecast), that have been selected to allow planners an opportunity to assess any system weaknesses.

Since it is not possible to model all possible future conditions, these cases are developed to reflect conditions that significantly stress the system, based on engineering assessment that reviewing these stressed conditions will lead to infrastructure that is sufficient for all other likely system conditions.[The previous paragraph stated the planners use “reasonably likely future system conditions,” but this paragraph says “significantly stress” the system. Discuss reconciling these two statements.” As an example, as the ERCOT grid experiences its maximum transmission usage on the hottest days of the summer, assessing system power-flows with peak system loads corresponding to extreme but reasonably possible hot weather conditions is likely to indicate many of the possible future system needs.

The Steady-State Working Group (SSWG) develops the primary base cases used to analyze future system capability. However, these SSWG cases are not designed for any specific transmission study. Rather, the SSWG cases are designed to provide transmission planners with a base model containing the possible future infrastructure and capabilities and limitations required for planners to develop study-specific planning cases. These studies begin with an engineering assessment of the model components and adjustments needed to reflect the appropriate assumptions for the specific study. For example, ERCOT planners adjust components in the SSWG cases to develop the models for the Regional Transmission Plan (RTP) assessment. Some of these adjustments are stipulated in ERCOT binding documents, while others are communicated to stakeholders through the annual RTP scope document. ERCOT develops RTP transmission models for both a reliability assessment and for an economic assessment of transmission projects.

Steady-State Working Group Base Cases

As stated in the SSWG Procedure Manual:

*“ROS Working Groups and ERCOT use SSWG base cases as the basis for other types of calculations and studies including, but not limited to:*

* *Internal planning studies and generation interconnection studies*
* *Voltage control and reactive planning studies*
* *Basis for Dynamics Working Group stability studies*
* *ERCOT transmission loss factor calculation*
* *Basis for ERCOT operating cases and FERC 715 filing”*

These 16 cases provide a range of load and system conditions and establish a common point of reference for the analysis of the transmission system. Perhaps most importantly, these cases represent the planned transmission topology and generation resources available for planning the transmission system in accordance with NERC Reliability Standards, the ERCOT Nodal Protocols and ERCOT Planning Guides. These cases represent a range of system conditions but not all possible system conditions, therefore, adjustments to load and generation are needed depending on the scope of the transmission analysis being performed.

The three fundamental categories of data needed to construct these power flow cases are expected generation, load, and system topology.  TSPs are responsible for ensuring that load information and topology information are provided for these cases, except for the high wind, low load case, for which the load information is provided by ERCOT Staff. Generation information is added by ERCOT staff based on information provided to ERCOT by Resource Entities via the Resource Asset Registration Form. In general, the SSWG cases are developed with all potential resources (including mothballed resources), allowing maximum flexibility to transmission planners to include or not include these units as appropriate for each study.

Each TSP provides load information according to anticipated load conditions as defined in the particular power flow case being constructed. The TSP provides loads so that planners can meet their obligation to plan adequate transmission infrastructure in accordance with the performance requirements of the ERCOT Planning Guides and the NERC Reliability Standards. Consistent with this approach each TSP provides load data relevant to the peak load conditions for the transmission facilities they own. The approach leads to a condition in which the total load in the case is higher than a corresponding ERCOT-wide coincident load forecast. That is, the ERCOT system serves a broad area in which one portion of the system will often be under peak load conditions while other portions are not. Therefore, the sum of each TSP’s individual load will be higher than the ERCOT-wide coincident load.

In most instances, the total load in future year SSWG planning cases is greater than the total generation available for dispatch. The factors that contribute to this circumstance include:

* the use of non-coincident load forecasts that exceed system-wide coincident peak forecasts, as discussed above;
* an increased amount of variable generation on the system, which is typically derated to reflect expected generation output at the time of peak conditions;[Discuss]
* Planning Guide requirements that only allow a planned resource to be included in the models if the resource has a signed interconnection agreement, air permits (if needed), adequate cooling water, and full collateral for any necessary transmission improvements; and
* reductions in the development time for planned generation, which then reduces the number of planned resources that meet the requirements for inclusion in the models.[Discuss]

In order for the planning models to solve, the amount of generation dispatched by resources must be equal to the sum of all the loads plus transmission losses. Because one primary purpose of the SSWG base cases is to communicate bus-level load expectations, it would not be appropriate to reduce loads to achieve a balance with available resources. As a result, SSWG base case developers use “extraordinary dispatch methods” for generation resources to balance load and generation. These methods include dispatching mothballed resources and increasing the dispatch of variable generation resources.

Because the loads in the SSWG cases are not ERCOT-wide coincident loads, transmission planners may need to adjust load and generation as appropriate for a given transmission planning study. Adjustments to an SSWG case may not be necessary for highly localized studies, such as an analysis of radial lines serving loads or portions of the system with net power flow into, as opposed to through, the area being studied. In other instances, adjustments to the SSWG case may be necessary to eliminate impacts of case development decisions such as extraordinary dispatch methods needed to make the initial SSWG case solve.

Regional Transmission Plan Cases

ERCOT develops two sets of cases as part of its annual Reliability Transmission Plan analysis: cases are developed to assess any transmission projects needed to meet the reliability criteria established in the NERC reliability standards, the ERCOT Protocols, and the ERCOT Planning Guide, and cases are developed to assess the economic benefits from proposed transmission projects.

The RTP Reliability Cases are created by ERCOT annually and are used to analyze steady-state system performance in regards to NERC and ERCOT reliability planning criteria. These cases are also used to evaluate transmission system upgrades when performance deficiencies are found.

The RTP Reliability Cases start from the SSWG base cases and are modified as specified in the Planning Guide and the annual RTP scope document. The RTP scope document is presented by ERCOT to the Regional Planning Group (RPG) each year to communicate any case-specific assumptions not stipulated in the Planning Guides and to solicit stakeholder comments on the process and assumptions to be used in the upcoming analysis.

The SSWG base cases are modified because some of the assumptions contained in the SSWG cases are not appropriate for the RTP studies. Planning Guide Section 6.1(1) states, in part, “These case models…provide *a starting point* for each required season and year” [emphasis added]. For example, the following adjustments to the SSWG base cases are typically made to create the RTP Reliability Cases:

* A transmission project is removed from the cases if it (1) is classified as a Tier 1, 2, or 3 project[[2]](#footnote-2), and (2) has not completed RPG Project Review.[[3]](#footnote-3)
* ERCOT compares its 90th percentile load forecast[[4]](#footnote-4) to the load forecast contained in the SSWG cases by weather zone and uses the higher of the two.
* If there is not enough to meet the load, the case is split into two or more regions (i.e., groups of weather zones) and loads outside the region being studied are scaled down to achieve balance with resources.
* The set of generation units matches the SSWG cases in accordance with Planning Guide Section 6.9. However, changes in generation dispatch assumptions are listed in the RTP scope document. These changes typically include modeling wind generation at a lower, more conservative output level, and turning off mothballed units in the area of study. Generation dispatch changes will be made during the course of the analysis in order to eliminate or minimize overloads on the system, similar to Security Constrained Economic Dispatch, which is performed in real-time. [Where is the statement above concerning wind generation modeling information documented? Previous RTP Scopes have often included provisions to dispatch wind at “SSWG base case output levels.” Likewise, previous RTP Scopes have been inconsistent in their treatment of mothballs. For example, the 2014 Scope says in one area: “If needed to meet the load and reserve requirements, mothballed units will be placed in-service in the reliability analysis per the SSWG Procedure Manual.” In another area of the 2014 Scope, under the section dealing with generation shortages it states: “Turn on mothballed units that are outside of the study area.” The 2015 Scope is vague concerning mothballed units. Finally, what is meant by “Generation dispatch changes will be made during the course of the analysis in order to eliminate or minimize overloads on the system, similar to Security Constrained Economic Dispatch, which is performed in real-time”? What does this mean and has it been previously documented anywhere?
* DC Ties are modeled according to their historical performance.
* Beginning in 2015, the RTP Reliability Cases include dynamic ratings for transmission lines corresponding to a 90th percentile temperature by weather zone. This change only applies to existing transmission lines that have dynamic ratings specified by the appropriate TSP.

Following completion of studies to assess needed reliability projects, ERCOT uses the RTP Economic Cases to evaluate expected future year transmission congestion and to plan any viable economic transmission upgrades. This economic analysis is conducted using hourly production cost simulation software, such as UPLAN. The economic analysis begins with the final transmission topology resulting from the RTP reliability analysis.

The generation set is the same as that of the RTP Reliability Cases but may be updated to include any generation units that achieved Planning Guide Section 6.9 requirements after the RTP Reliability Cases were created. The grid simulation software uses unit-specific cost and operational information, such as heat rates, startup costs, minimum up-times and down-times, to simulate Reliability Unit Commitment and Security Constrained Economic Dispatch. Wind, solar, and hydro-electric units are modeled with 8760-hour output profiles reflecting weather conditions consistent with modeled hourly loads.

The RTP Economic Cases use the 8760-hour average weather (or 50/50) load forecast developed as part of the ERCOT Long-Term Hourly Peak Demand and Energy Forecast. Transmission projects evaluated as part of the economic analysis must achieve sufficient system cost savings to offset their cost of construction and operation in order to be endorsed. As such, it is important that the model output represent expected cost savings. Using a 90/10 forecast, similar to the RTP reliability cases, would mean that indicated cost savings would likely only be achieve in one out of every ten years and thus would overstate the value of any future project. Separate from this effort, ERCOT and stakeholders are currently analyzing a possible future change in methodology that would employ multiple load forecasts with a probability weighting factor.

PLWG Review and Conclusions

The PLWG reviewed the load and generation assumption methodologies used in the CDR Report and the ERCOT Transmission Planning Models and noted the following key drivers for different methodologies:

* The CDR Report is used to calculate a planning reserve margin that can be compared to the results of an LOLE Study. The LOLE Study is based on a probabilistic analysis. This analysis considers the probability that load will be higher than 50/50 load conditions, as well as probabilities of generation unavailability and wind generation output being higher or lower than the assumed Effective Load Carrying Capability (ELCC). Even though a 90/10 load forecast is not explicitly analyzed, higher than average load conditions, such as 90th percentile load, are inherently incorporated in the stochastic simulation.
* The CDR Report is not used as the basis for recommending construction of new facilities but rather provides guidance to policy makers and the market regarding the need for additional resources in ERCOT. Transmission Planning Models, however, are used as the basis for recommending construction of new transmission projects.
* All of the assumptions used to develop the CDR Report are included in the protocols. To the extent that policy makers and market participants use the CDR Report in their decision making processes, they can perform their own analysis by adjusting the variables. For example, if a market participant does not think that a certain planned generation plant will get constructed, they can remove it from their reserve margin analysis and use that information in their decision making. [Discuss the basis for the previous sentence. Market participant decisions can affect ratepayers. The difference between various market participant decisions is not that they have vastly different effects on consumers; instead, the risk of the decisions on consumers is vastly different. A TSP decision to build new transmission places the risk of an incorrect decision on consumers. A generation developer’s incorrect decision to build places the risk on the developer, not consumers.]
* The CDR Report evaluates system-peak conditions and takes into account system-wide market forces. For example, the CDR Report includes various demand response programs that would be expected to activate under system-wide scarcity conditions. Conversely, the Transmission Planning Models are used to plan transmission projects, which are typically, but not always, local or regional in nature. Certain system-wide phenomena, such as demand response, may not activate when local or regional loads are peaking if the system is not at or near its peak.[Discuss: NRG does not believe transmission plans should totally ignore load resources, especially those that receive compensation and which have performance metrics. Generation resources providing responsive reserve, for example, which are paid the same dollars as Loads providing responsive, are included in the transmission plan, but the load resources are not. Both resources, however, are included in the CDR.]
* The SSWG base cases provide a starting point for transmission planners throughout the ERCOT Region to use in their analyses. It is important to have a generic model that every entity can begin with, but the load and generation assumptions may be modified as appropriate for a given study.
* The RTP Reliability Cases are used by ERCOT to model critical system conditions to plan reliability projects in a deterministic analysis. The ultimate outcome of this analysis is the construction of a grid that will be used by operators to manage reliability. Uncertainties about future grid conditions can lead to reliability problems, so planners must perform their studies with some conservatism. However, the assumptions used in these models should be reasonable.[NRG would like to discuss the current rationale for determining a “reliability” project. Numerous projects have been deemed “reliability projects” because there wasn’t enough generation to dispatch around a constraint. And in most of these cases there wasn’t enough generation ANYWHERE on the system, so how does transmission fix that?]
* The RTP Economic Cases are used by ERCOT to model forecasted congestion on the ERCOT System in order to plan economic transmission projects. Since economic projects are based on an assumption of expected savings, it is not appropriate for the model assumptions to be too conservative or the calculated savings may overstate the real savings of a project.

In light of these key drivers, the PLWG determined that some differences in the assumption methodologies between the CDR Report and Transmission Planning Models are appropriate. However, the PLWG also identified several assumptions that do not warrant different methodologies. While there may be no “right or wrong” methodology in many cases, the fact that differences exist may cause confusion. The PLWG concludes that changes to achieve consistency between the CDR Report and Transmission Planning Models may be appropriate for the following assumption methodologies:

1. The CDR Report methodology for inclusion of planned generation resources in the capacity calculation is different than the criteria used for the Transmission Planning Models. The criteria for the Transmission Planning Models can be found in Planning Guide Section 6.9 and was recently changed to include a requirement for planned generation resources to provide financial commitment to their interconnection TSP, along with a notice to proceed. This change was made to provide more certainty that planned generation resources included in the models will actually be constructed. [Discuss: When did PLWG collectively come up with a strong opinion on this? For a very localized transmission project, the PG 6.9 methodology may be, and I stress may be, fine. However, for larger “power transfer” projects, the PG 6.9 methodology may not be appropriate.]
2. The SSWG base cases and the RTP Reliability Cases should adopt the methodology for hydro-electric unit dispatch that the CDR Report uses for calculating hydro-electric unit capacity. This change would have very little impact on the Transmission Planning Models and would result in more consistency between the processes. If a planner would like to study a scenario with zero output from hydro-electric units this can be run as a one-off scenario. This change would require a change to the SSWG Procedure Manual and would also be reflected in the annual RTP scope document.
3. The SSWG base cases and the RTP Reliability Cases should adopt the methodology for DC tie import/ export levels that is used in the CDR Report. The SSWG base cases, RTP Reliability Cases, and CDR Report all use historic information to determine DC tie import/ export levels, but the methodologies are not consistent. Using the same methodology will improve consistency and reduce confusion. This change would require modifications to the SSWG Procedure Manual and would also be reflected in the annual RTP scope document.
4. It is appropriate for the SSWG base cases and the RTP Reliability Cases to model more conservative (lower) levels of wind generation output. However, when modeled wind generation output levels are increased as an extraordinary dispatch measure, the wind generation output level should be set consistent with the CDR Report methodology. Using the same methodology will improve consistency and reduce confusion. This change would require modifications to the SSWG Procedure Manual and would be reflected in the annual RTP scope document.
5. As more solar is developed on the ERCOT System, PLWG recommends that the consistency between the CDR Report and the Planning Models be reviewed.

NRG also would like PLWG to consider the following issues for this list, especially for RTP projects that are not local in nature.

* The load forecasts used in the CDR and the load forecasts used in previous RTP cases are often tens of thousands of MWs different, with the RTP loads being unreasonably high. The reason for this is the “higher of” methodology used in the RTPs and the use of non-coincident peaks in the RTP. NRG believes there has to be more consistency between the load forecasts used in the CDR and the RTP cases.
* Load resources receive full credit to meeting the CDR’s reserve margin, and these load resources receive compensation for their services. They should be included in both the CDR and RTP cases.
* RTP cases have recently been modeled with a resource planning reserve margin of zero. This is not realistic and transmission plans should not be so overly stressed that there is no generation left to dispatch around constraints. To include a planning reserve margin in an RTP case, provisions would have to be made to assume a forced outage rate for generation.
* RTP cases have recently been modeled to assume that every generation unit on the system, over 500 of them, can run at 100% availability and at their high limits during the peak hour. This assumption, when discussing the CDR’s “planning” reserve margin is appropriate. However, a transmission plan that is based on every unit on the grid being available is unrealistic.
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Appendix 1

Example Transmission Service Provider Load Forecasting Methodologies

LCRA

LCRA TSC receives load forecast information, consistent with loads reported in the ERCOT Annual Load Data Request (ALDR), from Load Serving Entities to use in developing a load profile for the SSWG power flow cases. This load forecast data contains the forecasted non-coincident summer and winter peak load on the low side of the substation power transformer for each delivery point. LCRA TSC derives a factor, the coincidence factor, to apply to each load in order to establish a load profile that is coincident with LCRA TSC’s system peak then adds transformer losses so that the loads provided for the SSWG power flow cases are representative of the load connected to the LCRA TSC transmission system.  The coincidence factor is derived from the previous year’s meter data for each delivery point.  LCRA TSC also analyzes the previous year’s meter data for each delivery point to determine an appropriate power factor to establish the real and reactive power component for each load modeled in the SSWG summer and winter peak power flow cases.  LCRA TSC determines the load profile for the SSWG DSA seasonal peak and seasonal minimum power flow cases by scaling the summer peak load forecast by load factor ratios based on an analysis of five years of historical meter data. The appropriate load factor ratio is then applied to the LCRA TSC system peak coincident load profile for each delivery point, transformer losses are added and an appropriate power factor applied to prepare the load profile for use in the SSWG seasonal peak and minimum power flow cases.

AEP

AEP tries to match our total load value to the value of the load during each operating company’s peak (TCC and TNC, individually). Our intent for the SSWG peak load (i.e. summer) cases is to represent a load scenario where the local transmission system is most stressed. We do this by taking the NCP loads, provided in the ALDR, and applying a factor that consists of the company’s CP load value divided by the total of the company’s NCPs. This factor is not applied to industrial loads which are kept constant throughout the cases. This factor is also not applied to “self-serve” loads, which are forecasted separately.  This philosophy results in the SSWG cases having a combined total AEP company load that is higher than AEP’s portion of the ERCOT CP load, but less than the combined total of the NCP at each load point.

CenterPoint

* Load data is based on ALDR submittal
* No non-member entities (i.e. electric cooperatives, municipal utilities, etc.)
* For CenterPoint Energy, loads fall into three classifications
	+ Distribution loads
	+ Transmission level customer loads
	+ Self-serve loads
* Distribution Load Forecast
	+ 102 degree F average temp across all CenterPoint Energy distribution substations
	+ CenterPoint Energy’s energy efficiency programs are incorporated
	+ DGs modeled explicitly if above 1 MW capability, shown as negative load based on historical operation
	+ Input
		- Area Service Centers provide residential and small commercial
		- Key Accounts provides large distribution customer
		- Projections for each substation are adjusted based on historical trends or similarly-situated customer demands
		- Substation adjustments can be positive, negative or zero
	+ New loads added to previous actual summer peak loads to produce forecast by substation
* Transmission level customer loads
	+ Do not vary considerably from year to year
	+ Existing large customers accounting for 80-90% of transmission level customer loads
		- Contacted by Transmission Accounts regarding their forecasted load and future load increases
		- Forecast load based on review of billing data of previous year’s peak during summer weekday afternoon hours
		- Future load increases are included once construction of new facilities has begun
	+ Existing small customers accounting for 10-20% of transmission level customer loads
		- Forecast load based on review of billing data of previous year’s peak during summer weekday afternoon hours
		- Future load increases are included once construction of new facilities has begun
	+ Future customers
		- Only included in model once they…
			* Sign letter agreement with CenterPoint Energy
			* Provide payment for service extension
			* Provide security for upgrades
			* Use customer provided load estimate
* Self-serve facilities
	+ Self-serve load and generation are modeled
	+ Modeling is based on actual net injection to the transmission grid and resource capability
	+ Self-serve load is off-set by self-serve generation
	+ Net load for self-serve customers is based on review of billing data of previous year’s peak during summer weekday afternoon hours
* Oncor

Oncor develops their ALDR based on substation bank peak load projections provided by their Distribution Planning Department and Industrial/Commercial load projections provided by the customer or customer representative. Oncor also develops load projections by weather zone. Load projections are considered an average (50/50 or 50th percentile). The Oncor weather zone load projections are adjusted to exclude system losses and then used to develop a “Target” for the SSWG base case loads. Non-conforming/non-scalable loads are determined and using an in-house program the remaining loads are adjusted based on the ALDR so that the target is met. If applicable, loads are also adjusted to include I2X transformer losses. Loads are applied to the appropriate PSS/E busses for use in the SSWG base cases. These loads are submitted during the SSWG case build process and adjusted if necessary during the SSWG case update process.

1. Protocol Section 3.2.6 contains additional detail about the calculation of the planning reserve margin. [↑](#footnote-ref-1)
2. The Tiers of RPG Project Review are defined in Protocol Section 3.11.4. [↑](#footnote-ref-2)
3. Planning Guide Section 3.1.4.1(1). [↑](#footnote-ref-3)
4. ERCOT uses a 90th percentile or 90/10 forecast (as opposed to a 50/50 forecast based on average weather conditions) in order to achieve a transmission system that is sufficient to meet future loads 9 out of 10 years. The ERCOT 90/10 load forecast is developed using the ERCOT Long-Term Hourly Peak Demand and Energy Forecast with a 90th percentile temperature assumption. [↑](#footnote-ref-4)