ASSUMPTIONS UNDERLYING THE LOAD FORECASTS UTILIZED IN ENTERGY'S AFC CALCULATIONS

April 1, 2011[1]

(1) Methodology

A. Native Load Forecast

Entergy uses various statistical methods, including regression methodologies, the neural network forecasting methods, similar day comparisons (models compare forecasted high and low temperatures to historical high and low temperatures), actual prior day native load, temperature and storm forecasts, and other extrapolation techniques to develop its native load forecasts, estimating the load and energy requirements for its native load for each hour over the remaining hours of the current day and for the following nine days.

Load forecasts for the time period beyond the first 10 days are obtained utilizing long-term hourly load projections. These projections are developed from econometric energy models, historic customer class load shapes, typical 10-year weather (temperature) patterns, major account feedback, expected wholesale contracts, and the impact of current and possible utility-sponsored energy efficiency programs. These forecasts reflect notable determinants in the econometric energy models including regional and national economic growth, demographic changes, customer adoption rates for energy efficiency practices and equipment, weather, prices, seasonality, and expected customer usage and behavior. The econometric models also include determinants such as known near-term load additions or deletions from large-volume industrial customers.

Economic driver data used in the econometric models for the time period beyond the first 10 days, both historical and forecasted, are obtained from Moody's Analytics. The data include both customized data for each operating company area and national drivers for a wide variety of variables.

Econometric sales forecasts for the residential class models are derived from separate usage per customer ("UPC") and customer count models, the outputs of which are multiplied together on a monthly basis to produce estimated total sales volumes. For the other classes, total usage is directly calculated by the models (i.e., monthly UPC can be calculated by dividing the output of those models by the outputs of the customer count models). The key drivers for the UPC/usage models are generally gross area economic output (similar to national gross domestic product) or real income, while customer count models are typically based on drivers such as population or households. The residential UPC and commercial usage models additionally incorporate end use variables such as appliance efficiencies and home size to account for the impact of changing end use characteristics through time. These models are generically known as Statistically Adjusted End Use (SAE) models.

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[1] Posted in accordance with NAESB Standard WEQ 001-17.6.5, adopted by FERC in Order 676-E

The Forecasted Native Peak Load includes and excludes the same loads included and excluded in the Actual Native Peak Load calculation.

B. System-Wide Load Forecast

The System Wide Load Forecast is derived by applying an escalation factor equal to the ratio between native actual peak load and the system actual peak load from the prior day to the native load forecasts for the current forecasted days.

(2) Weather Variables Used

Also underlying the native load forecast are: proprietary weather forecasts provided under commercial service contracts with Telvent DTN and ImpactWeather covering weather forecasts for the relevant geographic areas and publicly available temperature and weather outlooks, such as those released by the Weather Channel. The key weather variable underlying the short-term load forecasts for native load is temperature. Other weather variables, such as relative humidity, precipitation and wind, may be used by the forecasting analyst to adjust the output of the forecasting model. In some circumstances, such as following a major storm, anticipated customer restoration rates may be used to adjust the forecast.

For days beyond the next 10, temperature data is obtained from the National Weather Service (through weather vendor Telvent DTN) and converted to cooling and heating degree days for use in all models except for those instances where no dependence of sales to weather could be established. Actual data is used for the historical time periods and normal (defined as fifteen-year average ending December 2008) cooling and heating days are used for the forecasted periods.

Seven measuring points reflecting seven major cities within the Transmission Provider's native load footprint Jackson, MS; Little Rock, AR; New Orleans, Baton Rouge, and Lake Charles, LA; and Beaumont and Houston, TX which are included in the Weather variable. Weather data provided by Impact Weather, DTN Meterologix / Surface Systems Inc, and The Weather Channel for the seven cities are averaged based on their percentage of total native load, their respective percentages totaling to a System Average temperature.

(3) Actual Load Assumptions

Actual peak load data posted on OASIS is derived from metering data collected at points throughout the Transmission Provider’s transmission system to determine the load served by the Transmission Provider. The system-wide load is calculated as the sum of the generation plus or minus interchange. Native load is derived by subtracting the metering data associated with loads not served by the Transmission Provider under existing contracts with wholesale and retail power customers of the Transmission Provider, or the load the Transmission Provider plans and dispatches generation to serve from the system-wide actual load.

Existing contracts are not a consistently applied factor in native or system-wide actual load calculation, except to the extent that such contracts define native load customers. However, expiration of existing contracts or implementation of new contracts are anticipated in load calculations for the period prior to the change in the load impacting the historical load data used for the forecast, and during such period, a manual adjustment may be applied to the load forecast for the next day(s).

A. **Actual Native Load** is derived by summing the generation within the footprint of the Transmission Provider's transmission system with the interchange on company and system ties that measure the actual system-wide load from the previous day, and subtracting the load that was not served by the Transmission Provider under existing contracts with wholesale and retail power customers of the Transmission Provider, or the load the Transmission Provider planned and/or dispatched generation to serve.

B. **Actual System Load** includes all load on the Entergy Transmission System, including Native Load and the loads of embedded Balancing Authority Areas for which Entergy is contractually obligated to construct and maintain its Transmission System.

Entergy does not use the actual system-wide load calculation in its transmission capacity evaluation models. Rather, such capacity is evaluated by planning models in the various horizons that apply existing grandfathered agreements, and transmission services reservations and schedules to the Native Load Forecast posted on OASIS, and using the same metering points for the inclusion or exclusion of additional load as is used in the System Wide Load calculation posted on OASIS.

(4) Economic Assumptions

Economic assumptions are not a factor in the short – term forecast for days 1-10. The forecast for days 11 and beyond do incorporate an approximate 20 day window of the long term forecast, pulling in the load forecasted for the first year of the 15 year energy plan forecast into the "monthly energy plan" which includes the Transmission Provider's economic outlook for its service area.

These projections are developed from econometric energy models, historic customer class load shapes, typical 10-year weather (temperature) patterns, major account feedback, expected wholesale contracts, and the impact of current and possible utility-sponsored energy efficiency programs. These forecasts reflect notable determinants in the econometric energy models including regional and national economic growth, demographic changes, customer adoption rates for energy efficiency practices and equipment, weather, prices, seasonality, and expected customer usage and behavior. The econometric models also include determinants such as known near-term load additions or deletions from large-volume industrial customers.