FAQs

1. What is the reasoning for using state-level forecasts that would be allocated to the LRZ-level in the forecasting process?
   
   – Modeling at the LSE is not feasible from a financial or time standpoint. This would require the collection of proprietary data (for both electricity usage and for the various drivers such as population, income, employment, and manufacturing output) at the LSE and the construction of over 100 models based on that information. Thus, the decision to forecast based on publicly available historical information was made.
   
   – The use of allocation factors is driven by the use of publicly available data. The various drivers are available on a statewide basis, but not on a LRZ basis. This necessitates a statewide approach which is then allocated to LRZ-level forecasts.

2. What is the process for the allocation from state level to LRZ considering that an LRZ may include more than one state or a state is split between LRZs?
   
   – The allocation method is based on the fraction of each state’s load that is in a specific LRZ. This fraction may or may not be projected to change over time.
   
   – The LRZ forecast is then built up from the individual state components. So if a particular LRZ had 70% of state X’s load, 25% of state Y’s load, and 60% of state Z’s load, the LRZ load would be =0.7X+0.25Y+0.6Z.

3. On what weather assumptions will the forecast be based?
   
   – The forecast will use NOAA/NCDC’s latest 30-year (1981-2010) normal weather. A single weather station will be used for each state.
The weather stations were chosen based on proximity to the population center for the particular state, subject to complete data availability.

4. **What sources will be used for projections of forecast drivers?**
   - Projections of macroeconomic variables and population will come from a third party vendor (IHS Global Insight). Electricity and natural gas prices are also derived from the third party vendor. Weather variables will be based on normal values.

5. **How many years of historical data will be used in the forecast?**
   - This will be determined by data availability as well as model fit. While some data series go back to 1970 (or earlier), others only go back to 1990. Thus, the earliest year used in any forecast is 1990.
   - In order to find a good fit, the full data series is not used in some states.
   - The number of years varies from state to state.

6. **What considerations are there for those utilities that serve load in more than one state?**
   - The allocation factors will be based on the portion of each LRZ’s load that is in a given state. These allocation factors will have to account for multi-state utilities. While we would appreciate any direction that can be provided, historical state by state load breakdowns for multi-state utilities are available through EIA filings (forms 826 and 861).
7. How will the forecast process address local phenomena, such as strong/weak regional growth or the addition of a large load to a specific LSE?

– The macroeconomic projections vary across the individual states, with states experiencing stronger growth having more robust projections.

– In reality, all loads are individual discrete events. Most are too small to be noticeable individually, but in aggregate can have a significant impact. In general, this type of growth in small loads occurs gradually, resulting in a smooth or steady growth over time. Large individual loads tend to have a noticeable impact by themselves. Thus, the addition of a large load causes a jump in the total load. This results in load growth in a series of steps instead of being smooth and steady.

– The issue of whether an econometric model will capture a large load addition depends on whether the forecast of the drivers capture it. If the economic forecast projects a significant increase from one year to the next (as would occur with a large new load), the econometric model will project a corresponding step change.

– Even if an econometric approach does not capture the lumpiness of load growth for an individual locality, if the overall economic projections are appropriate in the long-run, it will be appropriate in the long-run. The econometric model will produce a smoother trajectory but will capture the load growth over time.

– As you forecast for a larger region, the impact of an individual large load is less significant than it is for a smaller area. Furthermore, while one LSE in a state or LRZ may experience a large new load in a particular year, others in the same region may not. An econometric approach for the larger region is entirely appropriate.
8. **How does the independent forecast account for demand response, behind the meter generation (distributed generation), and energy efficiency?**

   – No adjustments were made to the historical data because no demand response, behind the meter generation, or energy efficiency programs were exercised through the MISO market.

   – Individual LSE efforts in this area are not publicly known.

   – Forecasts are presented both before and after DSM adjustments, with the adjustments based on individual state requirements.

9. **Why was only one model used to forecast both energy and demand rather than develop two models one for energy and the other for demand?**

   – The data needed to build econometric peak models at the state level is not publicly available. LRZ level peak models are not realistic because demand data at the LRZ level do not go back far enough to get a reasonable model formulation.

10. **How is the energy forecast converted to a peak demand forecast?**

    – Conversion factors will be used to translate annual electricity sales forecasts at the Midcontinent Independent System Operator’s (MISO) local resource zone (LRZ) level to summer and winter non-coincident peak demands. These conversion factors are based on normal weather conditions at the time of peak demand and are determined from historical relationships between average hourly load for the year, summer/winter peak levels for the year, and weather conditions at the time of the peak demand.

11. **How are transmission and distribution losses modeled in the forecast and are transmission losses included in the forecast?**
The forecast was done at the customer (retail) level and then an amount representing distribution losses was added to it to bring to up to substation metered level. The distribution losses were estimated by comparing LBA data provided by MISO which is at the substation level to EIA data which is at the customer level, the difference being distribution losses.

Transmission losses are not included in the final forecast which is at the substation metered level. SUFG does not have data which will provide an estimate of the transmission losses between the generators and the substations.

12. **Why are growth rates only available for the variables in the state econometric models?**

   - The driver forecasts were purchased from IHS Global Insight and are proprietary.

13. **Why are the weather stations used in the state econometric models different than the weather stations used in energy forecast to peak demand forecast?**

   - The weather stations used for the state energy models were chosen based on proximity to the population center of the state because they are intended to represent the state as a whole. The weather stations used for the peak forecasts were chosen to be representative of the LRZs and in some cases this meant a different station than what was used in the state model.

14. **Why are allocation factors and load forecasts for Indiana and Kentucky and North Dakota and Montana aggregated?**

   - MISO asked us to combine the Indiana and Kentucky and North Dakota and Montana results because there was concern that certain information could be backed out of the Kentucky or Montana forecasts because they only have one utility in MISO.
15. Why did you only use a single weather station for developing the state econometric models?

   – A single weather station was used due to lack of time to properly investigate the possible use of multiple stations in some states as some stakeholders requested. This is something that will be considered again in Year 2 of the project. While SUFG is not convinced that multiple stations will improve the models because heating and cooling degree days are likely to be highly correlated across stations at the annual level, the use of multiple weather stations will be examined.

16. What type of forecast model are you using to forecast load in MISO, and why?

   – We are using econometric models at the state level. While end use approaches are valid and may provide greater insight into issues like energy efficiency, they are significantly more data and resource intensive. More basic approaches, like time series, are generally inaccurate. Econometric models provide greater accuracy than time series while still being feasible from a time and data requirement standpoint.

17. How did you determine the MISO Coincident forecast?

   – The LRZ coincident peaks were calculated by multiplying a coincident factor by their non-coincident peaks. The summer coincident factors were provided by MISO and based on data from 2005-2012. SUFG calculated winter coincident factors based on data from 2010-2012. Coincident factors are the ratio of the coincident peak to the non-coincident peak.

18. Why does the sum of the nine LRZ forecasts not equal the MISO forecast?
The arithmetic sum of the nine LRZ forecast does represent the MISO forecast on an energy basis, but does not on a peak demand basis. The MISO peak demand basis is for the system-wide (coincident) peak, while the LRZ peak demands are for the individual (non-coincident) peaks. Since the LRZs do not experience their individual peak demands at the same time (referred to as load diversity), their load at the time when the MISO coincident peak occurs will usually be lower than their non-coincident peak demand. Thus, the sum of the LRZ non-coincident peak demands is greater than the MISO coincident peak demand.

19. **Why is the independent load forecast for Indiana not the same as the forecast that you produce for the IURC?**

There are many reasons why the independent load forecast for the Indiana and the forecast produced for the IURC will be different. The general reasons are differences in data sources and modeling approaches. The independent load forecast is done at the aggregate retail level on an annual basis for the entire state using econometric models. The IURC forecast is built up from class level forecasts (residential, commercial, industrial, and other) using both econometric and end-use models and data provided by the utilities themselves.

The IURC forecast has a lot more detail behind it than the independent load forecast. For instance, the industrial sector is modeled at the level of individual manufacturing sectors (such as primary metals or automobiles) and the commercial sector is modeled by building type. The level of detail is often dictated by the geographic scope of the region analyzed, with more detail for smaller regions (like an individual utility) and less detail for a larger region, such as the LRZ or MISO system level (or the census division level for EIA’s modeling). This is because individual events or factors have a more significant impact at the smaller scale.
20. **Why are there load forecast values for 2013 and why are the annual growth rates negative for the initial year?**

- Annual retail sales at the state level are not available from EIA (expected availability is November 2014). Therefore, the state econometric models were used to “forecast” the 2013 values (as well as the 2014 numbers) to provide continuity between the historical data and the forecast period (2015 to 2024). SUFG will incorporate the 2013 actual values in the econometric model formulations for next year’s process.

- The negative growth for some states in the first year is a function of the values of the economic drivers from IHS Global Insight and the assumption of normal weather in the forecast years. If there is little or no growth in the variables that cause sales to increase (have a positive coefficient in the model) or strong growth in variables that cause sales to increase (have a negative coefficient), like electricity price, one can get stagnant or declining sales. The weather normal assumption can cause these results when the last year of actual sales saw more extreme weather (higher CDD or HDD) than normal.

21. **Is it an “apples” to “apples” comparison of uncertainty that is calculated in the 2015-2024 Independent Load Forecast and Load Forecast Uncertainty that is used in the MISO Loss of Load Expectation study?**

- No. The load forecast uncertainty in the Independent Load Forecast is determined by the variance of the error term in the econometric formulations. In essence, the error term represents the difference between the historical value and the value that the model comes up with given the historical values of the drivers. The load forecast uncertainty in the MISO Loss of Load Expectation study is driven by the variability of historical demand itself.
The econometric model will indicate a lower level of uncertainty because it does not incorporate uncertainty from the model drivers. For instance, the model does not capture weather uncertainty since HDD and CDD are assumed to be at their historical norms.