Joint Utilities Integrated Resource Plan (IRP) Stakeholder Education – Questions & Responses

Load Forecasting – Matt Rice

- Great recession – how has the great recession of 2008 changed trends and findings from load forecasting? **Response:** Historically, utilities would see year over year increases in load year. Vectren's load has flattened, which is a combination of the recession, utility sponsored DSM programs, and efficiency trends. We are not seeing a whole lot of load growth.
- Demographics – how do demographics impact load? **Response:** One example is household formation -this was disrupted following the great recession. Students moved back in with their parents after college instead of buying their own homes. The result was increased electricity usage at their parents' house, but a fewer number of households formed, which is a driver of load.
- Weather – is there a "true" weather forecast or how is weather constructed for the forecast? **Response:** Weather is accounted for in a couple of different ways. Heating Degree Days (HDD) and Cooling Degree Days (CDD) are related to historical usage. Historical weather is assumed to continue in the future. Utilities typically consider average weather from the last 10-30 years. In the demand forecast, Vectren has 10 years of peak producing weather in that model. Vectren keeps that average in the model and uses that to drive the demand forecast.
- How could some of the load forecasting drivers be more standardized across the utilities? Do they or can they at least come from the same sources? **Response:** I highlighted the common drivers although some utilities may not use all of them, such as the economy, weather, etc. Some of the sources likely are the same, Vectren relies on the EIA information provided by Itron.
- With respect to Matt Rice, for customer-owned generation in terms of load forecasting, what do you evaluate? Do you remove the generation from your forecast? **Response:** Many utilities include customer-owned generation and remove that from the load forecast. Vectren is working with Itron to look at the payback period and customer adoption rates, which will then be subtracted from the load.
- Slide 22, which load forecasting model was the most accurate going back in time? **Response:** One load forecasting model is not necessarily more accurate than another. Each model structure has a specific purpose and utilities may use different structures for different customer classes. Utility forecasters choose what they feel is most appropriate.

Resources – Scott Park

Resource Questions:

- When considering customer-owned generation in load forecasts, do you reduce expected load by the amount of generation that is anticipated from the customer-owned facilities? Or how precisely do you consider customer-owned generation? **Response**: This is a utility specific question and can be addressed further at the respective stakeholder meetings. Generally speaking, existing customer owned generation is factored into the load forecast and results in a net reduction in load. Proposed customer generation may be modeled as additional impacts to load forecasts or as selectable resources.

- Are the costs shown in today's presentation going to be used by all utilities in their 2016 IRPs? i.e. Capital cost of different resources on slides 33 and 34. **Response**: No, the data presented on slides 33 and 34 was just for illustrative purposes.
- How specifically can you measure the attractiveness and cost-effectiveness of utility scale battery installations versus other supply side options? **Response:** Batteries are evaluated like other resources in terms of performance characteristics, initial costs as well as ongoing operational costs. Utilities may consider grid energy storage benefits of batteries such as frequency response or renewables integration in addition to generation and load operational flexibility.
- How are T&D costs incorporated in the IRP process? **Response:** Transmission and Distribution (T & D) costs are incorporated in avoided costs in Demand Side Management (DSM) program analysis, which are included in the IRP. Utilities may incorporate transmission expansion plans and descriptions of smart grid technology and other system impacts as well.
- Are there inherent biases in resource planning that lead to the selection of certain resources over others? **Response:** There are no inherent biases in the resource planning process. Each resource is evaluated based on customer needs, economics, and each utility's respective operating characteristics.
- Do utilities remove/not consider wind and solar to be a form of a baseload, intermediate, or peaking resource? **Response:** No, the terms "baseload, intermediate, or peaking resource" are a way of grouping resources of similar capacity factors for discussion purposes. IRP modeling considers much more detailed resource specific data and selects resources throughout the 8,760 hours of each year based upon the resource characteristics and economics as appropriate.
- In regard to combined heat and power (CHP), it was generally a reduction to the load forecast rather than a supply-side resource. Would like clarification on if the utilities consider CHP to be a supply-side resource or not? **Response:** This is a utility specific question and can be addressed further at the respective stakeholder meetings. Generally speaking, CHP has been considered a supply side resource.

<u>Energy Efficiency (EE) Questions:</u>

- What do you see as consumer barriers to adopting EE? i.e. knowledge, income, etc. **Response:** This is a utility specific question and can be addressed further at the respective stakeholder meetings.
- What are the utilities' goals to increase outreach/awareness of EE to the most impacted customers? **Response:** This is a utility specific question and can be addressed further at the respective stakeholder meetings
- Shouldn't EE be fully included in IRP modeling and screened for economics in the IRP, rather than externally? **Response:** This is a utility specific question and can be addressed further at the respective stakeholder meetings

- As far as new EE measures and EE programs, how are they incorporated into the IRP analysis? **Response:** This is a utility specific question and can be addressed further at the respective stakeholder meetings.
- Is EE potential bundled by measure from the technical potential analysis based on similar costs, load shapes, or both AND then put into the model to select optimized resources? If no, why? **Response:** Each utility has bundled EE measures in a different way and this topic can be addressed further at the respective stakeholder meetings.

Scenarios & Sensitivities – Ted Leffler

- How much does it cost to run one scenario model? **Response**: The cost of running one scenario model will vary from utility to utility. The utilities have different vendors, some utilities may do run the model in-house, some may have the same vendor run the model, but the utilities have different pricing structures in their contracts.
- Base Case definition, p. 43 – when does a final federal rule such as the Clean Power Plan become part of the "Base Case" as existing law/policy? **Response:** The definition of a "Base Case Scenario" came directly from the 2015 IURC Director's Report. "The base case [scenario] should describe the utility's best judgment (with input from stakeholders) as to what the world might look like in 20 years if the status quo would continue without any unduly speculative and significant changes to resources or laws / policies affecting customer use and resources." The decision to incorporate different environmental regulations within the IRP process is utility-specific and may not happen at the same time.
- What is the definition of THE successful scenario? Return on investment (ROI)? Cost to customer? **Response:** It is up to the individual utilities and their IRP process to determine the most appropriate scenarios for consideration. Utilities are looking for the preferred resource plan for a specific scenario, so there may not be one right answer. The metric inputs for the resource plans are developed when the utility sets objectives for the IRP process. Therefore, what is labeled as "successful" or "preferred" may be different for each scenario or future world.
- How could the sources for assumptions and processes become more standardized across the utilities? **Response:** Each utility has unique characteristics, consultants/vendors, and software modeling systems, which would make standardization extremely difficult.
- Are utilities looking at a Regional Carbon Trading Scenario especially since this is a collaborative effort? **Response:** The assumptions about how the future will look and assumptions around environmental regulations (Carbon Trading, Carbon Tax, no Carbon rules) will be developed by each utility.

Regional Transmission Organizations (RTOs) 101 – Paul Kelly and Bill Sedoris

- What is unforced capacity? **Response:** MISO defines "unforced capacity" as the amount of capacity in MW assigned to a Planning Resource after accounting for its forced outage rate or historic availability. Unforced capacity is the summation of the capacity availability of a resource when the resource is available to serve or is in a planned maintenance outage. A resource's capacity availability is reflective of the duration and number of times it has been placed into a force outage. The North American Electric Reliability Corporation (NERC) defines a forced outage as:

    1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons.
    2. The condition in which the equipment is unavailable due to unanticipated failure.

  In MISO, the exact calculation of Unforced Capacity is dependent on the type of generating resource technology being evaluated. These calculations can be found in the MISO Resource Adequacy Business Practice Manual (BPM) BPM-011-r15, Appendix H – Unforced Capacity (UCAP) Calculation for Planning Resources. MISO's BPMs are available at: https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx
- How often is the information exchanged and updated? And how much is confidential? **Response:** The frequency of data exchange between a utility and MISO is contingent on the kind of data being exchanged. For example in MISO, both load forecasts and resource capabilities are provided on an annual and daily basis. Transmission topology is provided annually and changes are updated as needed. As a general rule, the RTOs do not release information on a company basis. Information is typically provided in aggregate within the zone or the entire footprint. Information, such as retirement plans or expansion plans, are kept confidential until all analysis is complete and the final determination has been made.
- Can supply-side resources located in the PJM footprint, with physical power flows into MISO, be used to meet MISO capacity requirements? **Response:** Resources located outside of MISO can be used as a capacity resource provided that the resource meets the requirements of the RTO and appropriate transmission is in place (physically deliverable to the market). These resources typically must be pseudo-tied into the receiving market, which means that sending a company's (RTOs) generation resource is telemetered into the receiving company's area and dispatched as if it was within the receiving area's footprint. The resources cannot be counted in both the PJM and MISO footprint.
- PJM and ISO New England both use downward sloping demand curves in their capacity auction, but MISO uses a vertical demand curve. Is there any movement to move MISO to a downward sloping demand curve? **Response:** While there have been discussions within the MISO stakeholder process on the vertical demand curve over the last few years, it does not appear that there are any plans at this time to move toward the vertical demand curve for the MISO capacity construct as a whole. However, with the

introduction of the new MISO Competitive Retail Solution Task Team (CRSTT), this issue may be resurrected for those retail choice states within MISO.

Within a pure competitive environment, the vertical demand curve provides the price-reserve margin values that the load would be willing to pay for. However, within the current MISO construct, price signals coming out of the auction are not reflective of the value of capacity. The impacts of self-scheduling (participating in the auction with a zero load bid and/or zero unit offer price) and the Fixed Resource Adequacy Plan (FRAP) dilute the true value of capacity. With the majority of the MISO footprint under a State or other regulatory construct, the use for a vertical demand curve is not appropriate.

Resource Modeling – Ismael Martinez

- Does the IRP Process allow for numerous model runs? How many?
  Response: Yes the IRP process allows for numerous model runs and there is no technical limit to the number of model runs that could be executed. The number of model runs completed is constrained by time and other factors. Model runs are used to establish optimal plans under each scenario. In addition, a utility may establish pre-defined portfolios (for example, early plant retirement portfolios, or portfolios with added renewable sources) and analyze those portfolios under various pricing scenarios. In addition, portfolios may be evaluated under a variety of sensitivities. If a company utilizes three scenarios, and creates optimal plans under each scenario, which are then analyzed under the other scenarios, that would equal nine model runs. Adding sensitivities or locking in specific resource decisions would require additional runs.
- On slide 75 – how will or do utilities equitably distribute emissions, do the utilities populate that scenario into the modeling?
  Response: Emission limitations may be added as a constraint for specific resources. Generally these constraints reflect known or anticipated annual or seasonal limits based on state or federal law. For example, a fossil unit may have a seasonal nitrogen oxide (NOx) limitation which may restrict its output during certain months.
- At what point – and how – are other plant additions from other RTO members considered? Where are assumptions drawn?
  Response: Utilities plan to meet their own load requirements. The impact of other RTO members adding capacity may be reflected in future RTO reserve margin requirements as well as in projected future capacity and energy market pricing assumptions.
- What is the criteria that utilities use to define the preferred plan?
  Response: How a utility establishes its preferred plan is dependent on the goals of the utility and its stakeholders. A number of factors may influence the development of the preferred plan including costs, economic development considerations, and risk mitigation.