RPG Meeting
October 21, 2014

Doug Murray
LTSA Scenario Results Update

- An error was found in how energy efficiency was accounted for in the load forecast of the High EE/DG Scenario
    - Forecast was redone adding 686 MWs of EE in 2018, increasing to 7,063 MW by 2029
    - Scenario rerun with increased EE
- Also ran a sensitivity to see how much solar would get built in 2018 under various solar capital cost assumptions

Q: Some of the costs are significantly lower. Are you still considering whether you'll rerun some of the analyses?
A: Not for the LTSA, but this would be more of an internal running on our part just to see what would happen if we run a model with all of the correct costs in it.
Q: Will you put some wording in the LTSA report about lower solar costs?
A: We had planned to do just that in a section of the report.

Sandeep Borkar
LTSA Update

- Current trends, high economic growth, stringent environment and global recession scenarios shortlisted for transmission analysis based on stakeholder feedback.
- Reliability cases were prepared per the LTSA scope.
- LTSA scenario assumptions lead to significant solar additions in the next decade (utility solar increases from 150 MW to about 10,000 MW)
- South/SC, we do site generation in Valley and that changes the pattern that you see. If you look today, you may see more needs than in the 2029 case assuming additional generation sites in the area.

Q: What peak capacity output are you assuming for solar?
A: On reliability chart/graph: purely based on profile from the URS. The reliability analysis uses 70% of the output from solar.

Q: What have you done for other seasons where solar is greatly reduced, but the load shape is different?

A: We looked at a March day with low loads. This is something we're aware of and want to keep an eye on.

Q: Slide 7. The first one is loads around LNG facility or the other line?
A: It's tied to that facility, but yes, it is the other line.

Q: How do you treat solar for winter peak?
A: I think we need to consider doing more winter peak analysis for a number of reasons. Winter peaks a bit later in the morning, so it's not like you have 0 solar, but you don't have much. Also need to consider that you've got areas of system that are winter peaking, think about future where you have more units that are seasonally mothballing. You plan your transmission system to be ok for summer peak then it'll be ok for winter peak. That assumption more and more is suspect because you have completely different generation mix.

RTP Update
Sandeep Borkar

- Reliability Analysis Summary
    - 2014 RTP studied 2015, 2017, 2019, and 2020 summer peak cases
    - N-1, G-1 + N-1 and X-1 + N-1 SCOPF studies were performed to identify reliability criteria violations.
    - Sensitivity cases analyzed
    - Sensitivity case analysis to be completed
- Economic Analysis Update
    - 2014 RTP economic analysis being run for years 2017 and 2020
    - N-1 secure case obtained after reliability analysis was used as a start case
- Next Steps
    - Preparing mitigation plans for 2015 violation
    - Finish running sensitivity analysis
    - Draft-RTP report sent out for TSP review and feedback
    - Complete economic analysis

Q: Is the total load that was used in reliability cases posted?
A: We posted the cases and I believe the loads that were used in the analysis were included in slides from previous RPG meetings.

2014 Draft RTP report was sent out for review and feedback to all the TPs. We encourage stakeholders to take this opportunity to provide feedback on the scope.

Q: Why is the draft RTP only sent to TPs for review? Why not other MPs? All of these affect the market and MPs should be able to take a look and ask questions before it is finalized.
A: It's been our practice to send to TPs so we can get the project descriptions correct. We don't want to describe a project and then have someone come back and say that's now how we would describe that project. The projects are posted on the MIS. If anyone has comments on any of the projects, we're certainly open to hearing those comments.

Q: Do you remember what reserve margins you used
A: 1375 MW of reserve in the case before its run. Would be a good discussion for 2015 RTP scope.

Q: Once projects make it into the RTP do they still go through RPG process?
A: Yes. Planning Guide Section 3, where it discusses all Tier 1, 2 and 3 projects in RTP, still need to go through RPG comment. ERCOT can use RTP as independent review for Tier 1 and Tier 2 projects.

2015 RTP Scope
Sandeep Borkar

- New TPL standards in effect
    - New off-peak will be studied as a base case along with summer peak cases
    - New contingency categories
    - Non-consequential load shedding no longer acceptable mitigation plan for some contingencies
    - Automatic tripping of elements where relay loadability limits are exceeded post-contingency
- Other Updates
    - Reserve margin will be used in reliability cases to address G-1+G-1 conditions
    - Dynamic ratings will be applied in reliability analysis
    - TPs will be requested to identify generic equipment type which may take longer to replace; studied as a first level contingency in N-1+N-1 test

2015 Draft RTP scope and process document was sent out for review and feedback. We encourage stakeholders to take this opportunity to provide feedback on the scope.

Q: Does this affect steady state?
A: SSWG has discussed additional ratings so you can put a trip rating in the PSSE. The plan is to make these assumptions, but if we see problems, we'll get back to the TSPs and ask more detailed questions from there.

Q: What about getting loadability settings from the TOs?
A: We make conservative assumptions, then if we see problems, we'll go and ask on a line-by-line basis.
Q: Is there a long-term goal to have those included in steady state cases?
A: SSWG had these discussions and that's the plan.

Q: Question about new categories
A: SSWG is updating their contingency list to take the new categories into account.

*NERC allows till 2020 "raise-the-bar" requirements

Q: When will these new requirements take effect?
A: The 2015 RTP is when we will first be studying these and planning projects with these new requirements.

Q: Will a cascading event be included in the scope? Is there a reference in criteria that defines cascading? Any plans to discuss what ERCOT considers a cascading event?
A: I think that's a requirement in standard, identify what you consider cascading criteria.

Q: Will the results of the short circuit studies be shared with both Transmission Owners (TOs) and Generation Owners (GO)s?
A: At this point, the plan was to just work with the TOs. We may have to review our process on the BES equipment which belongs to the GO.

Q: 90th percentile, high temperature profiles?
A: By weather zone, pick 90th per. temp and pick the rating that's associated with that temperature.

Q: You're intending to just use the 90/10 forecast for the load part of it?
A: No, the comment was simply for the dynamic ratings and what temperatures would be used to extract the dynamic rating. The load is a separate discussion and we'll get to that.

Q: Changes and criteria for planning---any change how ERCOT is going to run SCED? Are the contingencies in SCED going to change? That could affect a lot of people's expectation of risk.
A: No plan to change SCED or how operations run contingencies. The standard is about the planning horizon, but it brings up interesting discussion.

CPS/LCRA Transmission System Addition: ERCOT IR Update
Sun Wook

- ERCOT has completed the "need" analysis and confirmed the reliability need for the project
- Next steps: perform X-1+N-1 analysis for the base case, complete the initial screening and select options for further analysis, and perform detailed analysis for options selected.
- See Appendix for maps of 13 initial options

Prabhu Gnanam
Brady Area Project: ERCOT IR Update (Tier 2)

- Note on Slide 4: Katemcy is a 69 kV line, not 138 kV
- Base case: 2014 Dataset B for 2017 summer peak case, posted on May 15, 2014.
- Project options from submittals: 13 study cases were identified
- Common upgrades: most of the lines terminating at North Brady, City of Brady Tap and South Brady.
- Options were highlighted and discussed.
- ERCOT preferred option: Option 11 upgrades. Total cost estimate approx. $36 million.

Q: Can you identify what is the type of load growth that you're experiencing in the Brady area?
A: 2012 experienced 45 MW for the area, projected load for 2016 is around 60 MW for the area.

Q: Why was Alternative 9 not included?
A; Alternative 9 did not meet the N-1 -1 requirement.
Q: Did you do any assessment of what would be required to solve those contingencies?
A: We did for Options 4, 4a and 11; all the other options needed significantly higher reactive resource to resolve those contingencies.
Q: So 4, 4a and 11 work as long as you can add 20 Mvar of reactive support?
A: Yes

Prabhu Gnanam
CNP Jones Creek Project ERCOT IR Update (Tier 1)

- 721 MW load addition at Quintana substation
- Base case: 2018 reliability final case from the 2013 RTP
- Discussed Option A ($125 million), B ($80 million) and C ($78 million)
- Next steps: review additional feedback, prepare the final report, present ERCOT recommendation to TAC and ERCOT Board of Directors

Q: You're not weighing in on any of the 3 options? Just noting that they're good from a thermal perspective?
A: True

Q: Jones Creek, what is the Houston load in the case you have, after you adjust the load, is the Houston load higher or lower than the 26355 figure on the SE case?
A: Showed numbers on slide 4. Centerpoint load.
Q: So that's not the coastal load?
A: No, that's the Centerpoint load.
Q: In the previous 2013 SE case, the coastal load was 26,355 MW, now after your adjustment for this case was this load changed and how much did it change?
A: This is a 2013 RTP case.
Q; On the case you used for the Jones Creek Study, what's the Coast Load?
A: I'm hearing the number was 300 MW higher than the 2013 SSWG. I can look it up and provide the details.

Q: On the G-1, N-1 analysis on slide 4, which units are you taking out?
A:. loss of a single unit at STP substation, 1375 MW, or the loss of a single unit at WAP substation, 658 MW, or the loss of all steam turbines at AMOCO substation, 350 MW

Fred Huang
Valley Update

- Valley overview: 2014, 2015 and 2016. Frontera facility availability. Does not include the assessment beyond 2016.
- Study scope
  - Determine whether absence of Frontera will cause violations of ERCOT and NERC reliability planning requirements that would not occur if the facility were available.
  - Analyze whether all or a portion of Frontera facility might be needed until the reliability criteria can be met.
- Discussed study scenarios
- Conclusions
  - The system maintains acceptable performance under steady state conditions
  - TOs will need to maintain a high voltage profile in the Valley region during high demand periods
  - If the Frontera facility is not available, planned outages for major 345 kV lines and generation in the Valley region will be further limited and will require greater coordination by ERCOT.
  - Stability/supply issues could be mitigated if the Frontera facility were available in ERCOT during high demand periods that coincide with the outage of major transmission or generation elements.
  - Additional system upgrades will likely be required to reliably serve Valley load after 2016 if the Frontera facility is not available after 2016 summer.

Q: Can you remind us how you count hydro facilities in assessment studies?
A: Hydro units in the Valley region were turned off in this study.

Q: Did you include any block load cases from the LNG facility that's planned down there?
A: No.

Q: When you say Frontera units are not available, do you mean the plant is not available for planning purposes?
A: Yes - Frontera units are not available for ERCOT.

Q: Looking at Frontera, do those turbines have to be shut off before you can actually switch into and out of ERCOT? Cold switches or hot?
A: Yes, and it may take couple hours to complete the switch.

Q: In the Executive Summary that was sent out last night with the report, in the study findings, there was a statement at the end of the first paragraph—NERC reliability requirements….in effect 2016. Can you go into those details?
A: NERC TPL-001-4 has been approved to replace the existing TPL and will be effective in 2016.
Q: So the new requirement is that you'd be post-contingency stable under G-1, N-1 conditions, is that correct?

A: Yes
Q: Does the change allow for loss of load?
A: No loss of load for G-1+N-1. Allow loss of load for G-1+G-1 before 2020 but need to have a solution implemented by 2020.

Q: Study Scenarios for 2016 summer peak. Did you always assume that the new lines were in place or did you study scenarios where there was a potential delay in getting these lines energized?
A: Studied as in-service.

Q: In previous month's RPGs, there have been indications that there was a need for additional transmission improvements. Is that still ongoing or what is the status of future transmission improvements.
A: We continue to do the assessment for the Valley region, we are looking at 2016 and beyond.
Q: So this is just an update and you're still working on the study.
A: Yes and in this one, we're only looking at the Frontera impact.

Fred Huang
West Texas Export Capability

- Two reasons for assessment
  1. Assess the impact of series capacitors on the West Texas export capability
  2. Need to revise existing west-north transfer
- Discussed studies and results
- Propose retirement of the W-N-IROL/GTL
    - Post retirement: only allow up to 6 circuits on outage on the W-N interface

Q: How are those zones defined?
A: The zones were defined to assess if we observe any additional transfer limit within West Texas

Q: You said you had 8 capacitors planned. Are they planned or in-service?
A: Most constructed, but not in-service.

Slide8

Q: Is it really logical that we'd be running at that level (99.43%)?
A: This is the assumption to study the high wind output and transfer condition.

Q: Slide 8—200 MW export capability reduction. Same thing to say 200 MW constrained?
A: it is a 200 MW export capability reduction under high wind output condition if we by-pass all series capacitors in West Texas.

Q: Cost benefit analysis that was done assumes that all capacitors were in-service correct?
A: Yes
Q: Is that a good assumption for the cost benefit?
A: Part of it will depend on what we get from these studies and what comes out of the PUC discussions. We could be in a situation 6 months from now where maybe there are some series capacitors that get turned on, and then there's a possibility that doesn't happen. Right now, we're going to hold this assumption, but if it looks like it's not a good long-term assumption, then we'll revise the analysis.

Q: Did the analysis for the economic congestion impact look at the constraints due to system constraints or just due to voltage stability?
A: Economic congestion impact looked at the constraints due to system strength, thermal limit of the transmission grid with/without series capacitors in West Texas.

Q: It may be beneficial to look at a low load case to see what kind of impact it has on your results. Is there a point where you get 60%, 80%? At what point of wind penetration is there an issue?
A: The wind penetration is not directly limited by load level, but also depends on other factors, like system inertia and generation reserves for frequency response. ERCOT will closely monitor the system development and there is no hard limit on the wind penetration in the ERCOT system.

Q: That doesn't require any TAC approval or ROS right? That's ERCOT approval.
A: We'll share the result with the working group and then eventually we'll rely on Operations to determine next steps.

Q: Prabhu circulated some Category C&D study results. What is the status?
A: We are currently reviewing the comments and the next step is ERCOT will look at comments and see if we need to identify any projects based on categories C&D.

Q: Did the Jones Creek project include all generator outages?
A: We'll look at contingencies and generator outages and see if we see something new that needs to be updated. But we'll check all of our generator outages and make sure we've got everything.