EIPC Gas-Electric System Interface Study
Target 2 Sensitivity Descriptions and Modeling Assumptions – Round 2

Proposed Round 2 sensitivity cases are identified as green cells in the Excel spreadsheet entitled *"Combined Target 2 Sensitivity List"* dated July 3, 2014. The planned modeling approaches to defining the Round 2 sensitivities are described below for each proposed sensitivity case.

Sensitivity 2 (HGDS) and Sensitivity 2 (LGDS) – Remove incremental / decremental natural gas price changes from the High Gas Demand Scenario (HGDS) and Low Gas Demand Scenario (LGDS).

The preliminary results in the draft Target 2 report show a significant difference in electric sector gas demand among the three scenarios. See, for example, Figures 21 through 24 in the draft Target 2 report. Several variables change among the three scenarios: electric load forecast, natural gas prices, and resource mix are all materially different. Sensitivity 2 will apply the Reference Gas Demand Scenario (RGDS) fuel price forecast to the HGDS and LGDS to isolate the impact of this variable. No other changes will be made to the input factors.

Sensitivity 23 (RGDS) - High/Increased LNG exports

Sensitivity 23 analyzes the impact of including additional LNG export facilities along the Gulf of Mexico and the Pacific Northwest, and tripling LNG exports relative to the RGDS by 2023, consistent with the LNG export forecast in the AEO2014 Reference Case. AEO2014 forecasts total U.S. LNG exports will be 3.45 Bcf/d in 2018 and 6.9 Bcf/d in 2023, reflecting an average capacity factor for the LNG export terminals of 73%.[1] Six export terminals are assumed to be operating by 2022 with the first, Sabine Pass (2.2 Bcf/d capacity), starting operations in 2015, one year ahead of the RGDS forecast. In addition to Cove Point, MD (1.0 Bcf/d) in 2018 and Freeport, TX (1.4 Bcf/d) in 2017 in the RGDS, the other terminals included in this sensitivity are Lake Charles, LA (2.0 Bcf/d) in 2019, Cameron, LA (1.7 Bcf/d) in 2020, and Jordon Cove, OR (1.2 Bcf/d) in 2022.[2] GPCM models supply and demand across North America, and changes to levels of gas exports outside of the Study Region can affect gas flows and basis within it. For the peak day analysis in GPCM, all of the LNG export terminals are assumed to operate at full capacity, so the maximum capacity (rather than the annual average) will be assumed for each of the export terminals.

Sensitivity 31 (RGDS) – Very Cold Snap: 90/10 Electric and RCI gas demand

[1] The delivered price of the LNG exports is not relevant for GPCM modeling purposes.
[2] The LNG export terminals selected and the capacity of each facility is based on the FERC Summary of the Office of Fossil Energy Department of Energy Applications, March 24 2014, *Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower-48 States (as of March 24, 2014)*.

Sensitivity 31 envisions a Study Region-wide cold-weather event when all PPAs experience their respective 90/10 winter peak loads coincidently.[3] Electric load forecasts will be derived from each PPA's most recently published 90/10 load forecast, if available. If not available from public sources or directly from the PPA, LAI will use the non-coincident historic peak demand for each LDA observed from Winter 2013/14, and scale the historic peaks based on the load growth factor from the 50/50 forecast.

For LDC forecasts that include both a "Normal Day" condition and a "Design Day" condition, the "Design Day" forecast will be used to represent a 90/10 RCI forecast.[4] For customers where such a forecast is not available, deliveries on the Study Region-coincident peak RCI demand day from January 2014 will be escalated at the AEO2013 Reference Case growth rates used in the RGDS, applied by census region. If an LDC has a forecast in the public domain that does not include a "Design Day" condition, then the January 2014 demand will be used as the applicable basis, escalated at the growth rate included in the published forecast.

Natural gas prices will be the non-coincident peak spot delivered price observed in the winter 2013/14 for each Zone. (Note that these non-coincident spot delivered prices may be higher than those incorporated in Sensitivity 1, which used the spot prices on the date when the average of six pricing points representing the key pricing point for each PPA was the highest.)

<u>Sensitivity 33 (RGDS)</u> – Sensitivity 31 + High Forced Outage Rate for Coal and Oil Units

Sensitivity 33 is intended to mirror the extreme weather events in January 2014 when several PPAs experienced a higher-than-average forced outage rate (FOR) for their respective coal units, and, in some PPAs, for oil-fueled units as well. This sensitivity will test the ability of the gas system to compensate for unavailable coal and oil-fired capacity during extreme weather events. Electric and RCI loads from Sensitivity 31 will apply. We will also use the same fuel prices as for Sensitivity 31.

The forced outages will be modeled deterministically, with all coal and oil units derated by the maximum FOR percentage that was experienced by each PPA in January 2014 on the day when the total unavailable capacity was the greatest. Therefore the maximum FOR will be differentiated by PPA. For PPAs where the default FOR is greater than the maximum observed during January 2014, then the default FOR will apply. For modeling purposes, LAI will assume that the maximum coal and oil-fueled unit outages across the Study Region are coincident. In order to isolate the effect of higher FORs for oil and coal units, the FOR of gas-capable units will remain unchanged. LAI will adjust the FORs of the coal and oil resources, if needed, to avoid any load curtailment.

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[3] Since the "90/10" winter peak forecast represents an event with a 10% probability of occurrence, the probability of all six PPAs experiencing this event on the same day is considerably lower than 10%. The combined probability cannot be readily quantified.

[4] The "Normal Day" condition is used as the basis for the RGDS forecast.

Sensitivity 34 (RGDS) – Maximum Gas Demand on Electric Sector

Sensitivity 34 evaluates the capability of the gas pipeline infrastructure assuming maximum gas usage by all gas-fired generation in the Study Region. To induce maximum gas demand in the electric sector, LAI will make the simplifying assumption that the delivered price of natural gas is $0/MMBtu, thus ensuring that gas-capable units run flat out, or near flat out, over the forecast period. Non-fuel, variable O&M (VOM) costs applicable to gas-fired generators will remain unchanged relative to VOM costs used in the RGDS. We will also assume that the RCI demand is inelastic, and will therefore remain unchanged in this sensitivity.

Sensitivity 36 (RGDS) – Sensitivity 33 + Selected Nuclear Units Are Unavailable

During January 2014, certain PPAs experienced outages of nuclear units, in addition to coal and oil-fired units. The purpose of Sensitivity 36 is to test the gas system capability under the 90/10 winter conditions if selected nuclear units experience forced outages, in addition to the increased FOR on the coal and oil-fired units modeled in Sensitivity 33. Based on information provided by the PPAs, the following nuclear unit outages will be modeled:

- In TVA, Sequoyah #2 will be forced out of service during the winter peak day in 2018 and 2023.
- In IESO, one Bruce unit and two Pickering units will be forced out of service for the winter peak day in 2018, and one Bruce unit and one Darlington unit will be forced out of service during the winter peak day of 2023.
- In PJM, all of Byron and Quad Cities will be forced out of service during the winter peak days in 2018 and 2023.

RCI gas demand and fuel prices will remain unchanged. The capacity assumed to be unavailable will be adjusted, if necessary, to avoid any load curtailment.

Sensitivity 37 (RGDS) – Sensitivity 13 + Canaport Converted to LNG Export Facility

Sensitivity 37 evaluates the capacity of the gas pipeline infrastructure assuming that the existing Canaport LNG import terminal in New Brunswick is converted to an export facility by 2023. While Repsol has released a preliminary announcement of a plan to convert Canaport to an export facility, no information is public regarding the details of Repsol's export regime, liquefaction capability, system-wide improvements to ensure deliverability, or external commitments with LNG offtakers. Therefore, LAI will model an assumed Canaport export facility with a maximum daily liquefaction capability of 1.0 Bcf/d, similar to Cove Point.[5] All

[5] The 1.0 Bcf/d capacity for Cove Point is based on the listing of Applications Received by DOE/FE to Export Domestically Produced LNF from the Lower-48 States (as of March 24, 2014) and the Dominion Cove Point filed application with the Office of Fossil Energy of the Department of Energy: FE Docket No. 11-128-LNG.

new pipeline projects modeled in Sensitivity 13[6] will be included to facilitate gas delivery from Marcellus and Utica to Canaport. While reversal of flow on M&N to Canaport likely constitutes a straightforward engineering modification, upstream improvements on Tennessee and/or Algonquin to avoid denigration of RCIs' primary firm entitlements will be required. Additional pipeline reinforcements will be added on a generic basis up to 1.0 Bcd/d over and above the capacity that would be available absent the LNG export facility to ensure transport of sufficient gas quantities to the Joint Facilities System in northeast MA, for redelivery on M&N to Canaport. In light of the regulatory and commercial / market milestones associated with developing Canaport as an LNG export facility, this sensitivity will be run only for 2023.

[6] Sensitivity 13 is entitled *"Increased infrastructure to enable additional Marcellus/Utica natural gas flows into neighboring PPAs."* – As applied to the RGDS.