NGTDM CDR Review (Part 2): 07/21/15

Participants:

- Joe Benneche
- Andy Kydes
- Mike Cole
- Katie Dyl
- Angelina LaRose
- David Daniels
- Peter Whitman
- Robert Brooks (RBAC)
- Lauren Busch (Leidos)
- Sandy Sanders (OnLocation)
- Yelena Dandurova (Leidos)
- John Meyer (Leidos)

These notes represent one person's summary of the discussion which took place at the meeting and were not reviewed by the participants for accuracy.

The meeting was a follow-up to the discussion of 06/17/15, completing the review and comments about the NGTDM CDR. This meeting was primarily focused on questions and suggestions from Robert Brooks [RB] (of RBAC) about the proposed model structure.

Joe Benneche [JB] moderated the discussion, supported by a PowerPoint presentation (cdr_review.pptx) that summarized key conclusions from prior meetings and served as an introduction to [RB]'s observations. (*For convenience, references to specific slide numbers are identified as {PPT_#}*)

[JB] summarized the operation and requirements of the NGTDM, noting that NG consumption flows from the demand modules (residential, commercial, and industrial), and the model uses supply curves to return prices by sector and region, also estimating NG exports and imports. One of the expectations of the new model is that it will enhance the characterization of NG transactions with Canada and Mexico, as well as imports and exports of LNG. Pipeline capacity is a secondary concern, of interest primarily in that it affects prices, but is not considered a planning tool. {PPT_2}

[JB] briefly reviewed various modeling structures that had been conserved {PPT_3}: linear programming (LP) nonlinear programming (NLP), mixed complementary programming (MCP), & Agent-based. In competitive markets the various approaches provided similar results, absent non-market constraints. The question was how to optimize flows over a network in a manner that would provide confidence that the real world is represented. If regional growth is forecast, marginal prices can be representative, and agent-based systems will provide the same result as optimizing. Because of a lack of clear superiority, the modeling approach that is easiest to manage should be selected.

Andy Kydes [AK] noted that agents are not necessarily limited to refineries, but may also be individual industries or industrial sectors (such as chemical & allied products). Large players dominate the solution for different sectors.

[JB] countered that capacity planning decisions are based on market prices, which are not significantly affected by individual actors.

[AK] acknowledged that it may be appropriate to assume that everybody operates in a competitive market for modeling purposes.

Peter Whitman (?) [PW] noted that a competitive market assumption is fine, but violations of this assumption may distort results, for example, in cases of oligopoly.

David Daniels [DD] discussed non-competitive issues, and how they may impact model results. The existence of imperfect markets, regulation, and everybody operating in their best interests may yield different solutions than one resulting from the goal of maximizing global profit.

[JB] expressed a desire to minimize the use of minimum constraints in the modeling approach.

[RB] agreed with [JB] about the inability of individual consumers to impact the market price. He also tentatively agreed with the need to avoid minimums except with respect to negative delivery prices. He cited an example of Transco sending NG to the Northeast, negative price differential notwithstanding, due to the provisions of long-term contracts. Such situations would justify the use of minimum flow constraints in the model. This would depend on the level of aggregation in the model, but geographical distributions would, in general, need to be accommodated.

[AK] observed that some long term contracts contain clauses that adjust in response to price, and suppliers may wish to diversify contracts by including adjustment clauses to permit delivered price adjustments given regional market conditions.

[RB] suggested that this may be more of an issue in near-term forecasting, but as long-term contracts expire, they would be replaced with contracts that reflect a more current understanding of production/supply/demand trends. His view was that minimum constraints are more of a short-term issue, and could be removed from long-term forecasting.

[AK] claimed that pipeline O&M costs are already amortized, and supply contracts always have adjustment clauses. [RB] agreed, noting that market prices won't change based on transient contract terms, and longer term impacts are not critical.

[JB] expressed a need for a more detailed model, providing a greater level of regional granularity, perhaps, if necessary, at the state level in order to pick up market dynamics.

[RB] asked if he were considering regionality from the perspective of having common supply/demand data.

[JB] responded that he was considering sub-state supply issues, but there is no plan for sub-state demand, due to the lack of data; one exception may be in California, but reliable data still may be a problem. He expressed interest in considering a central node for each state.

[RB] indicated that he may have some suggestions, and proposed having an offline discussion at another time.

[AK] followed up, noting that in California, north/south pipeline capacity has been limited, and asked whether that had been corrected.

[RB] responded that this is no longer much of an issue, as NG can easily be brought from out of state to both halves of California, so transshipment is no longer important.

[PW] asked what level of sub-regional analysis is most appropriate for the proposed model. [RB] responded that North vs. South California would be fine, and that Texas should be also divided, though he made no specific recommendation.

[JB] addressed the general modeling approach that had been selected, concluding that an NLP with a quadratic objective function would best suit the modeling goals. {PPT_4} He also indicated that, with regard to the prices passed to the demand modules, there was an *a priori* decision to associate the NG spot price with the energy-intensive industries, and city gate prices with the residential and commercial sectors. He expected the model to run monthly, balanced separately, with no connection between months—almost a parallel model within a system when parts don't interconnect. {PPT_5}

[RB] asked how to accommodate seasonality effects on the demand side if there were none on the supply side.

[JB] indicated that it would be necessary to incorporate storage to mitigate seasonality. [PW] noted that storage is a limiting factor.

[RB] discussed the challenges of incorporating storage, noting that multi-period optimization suggests perfect foresight, which assumes demand forecasting has no uncertainty. There is a need to combine empirical and behavioral factors in the model, and to regard storage as a risk mitigating factor. He suggested projecting changes in storage capacity exogenously, based on historical trends. The difficulty is in the NE, where increasing gas production results in price drops because storage withdrawals compete with new production. Either storage should be tied to historical trends or it should be assumed that storage in the future will behave differently. He noted that if supply prices decline during the winter months, then storage assumptions may need to be revised.

[JB] explained that the model estimates what national storage will be per month, but there is no current regional distribution of flows into storage. It would be desirable too predict changes in storage over time, but it is necessary to conduct more data analysis. In the current model, storage is based on economics.

[PW] added that changes in NE production drives changes in historical storage patterns. [JB] agreed, noting that it was important to look at these trends to assess the dynamics of storage and develop suitable algorithms.

[AK] stated that if there were a price depression, too much storage would lead to a one-year mistake that wouldn't be repeated. If pipeline capacity can meet seasonal peaks, then storage is less important. Storage can be considered to be an alternative supply, with an incremental maintenance cost. Planning is based on worse-than-normal seasonal impacts, but now there is plentiful supply that was not there earlier.

[JB] asked whether storage customers are contractually required to take a certain volume of NG. [RB] responded that contracts have 'ratchets' that restrict customers in the use of storage, including limitations on inflows & outflows in order to maintain the system.

[JB] then discussed pipeline tariffs {PPT_6}, noting that supply curves will be based on historical differentials between spot prices and city gate prices, including: fuel charges, fixed charges, and variable tariffs. He suggested the development of a pair of variable tariff curves in order to accommodate bi-directional flows. Issues to be considered include whether prices in such a system would be symmetric (he assumed yes), and the treatment of depreciation, refurbishment, and additions to capacity & compression.

[AK] noted that, when considering pipeline expansion, stakeholders are provided with potential costs, but that such estimates are generally inaccurate.

[PW] suggested that dealing with pipeline rates that are constructed by segment would be challenging from a modeling perspective, and [JB] asked whether reservation fees are segment-specific.

[RB] stated that shippers make the market, not pipelines; pipelines sell capacity. Pipelines may create a secondary market through capacity release, but flows are reflective of price differentials cross the country. He noted that pipeline tariffs are captured in a database—there is good data in terms of price differentials, which can be used to build supply curves. Daily prices are available for a long time, and the model should reflect that higher pipeline utilization should lead to higher price differentials between upstream and downstream.

[JB] observed that it is difficult to aggregate smaller components to represent a larger aggregate system.

[RB] discussed how bi-directional flows and seasonality are important issues, recommending against using the same pricing arc, but rather to build separate segments with different cost curves. In contrast to the earlier assumption, he stated that bi-directional tariffs would not be symmetric. ([JB] indicated that, within each model period, flows would only be in one direction.) [RB] suggested, for example, looking at southbound flows as a different pipeline, and to consider the model as a series of linked segments where cost is imposed at the northern terminus.

[AK] asked whether costs are additive across segments, or is there a discounting process that should be incorporated. [RB] responded that costs are based on capacity utilization in each segment, and [JB] emphasized that the primary interest of the NGTDM is in the total cost of transportation.

[JB] then discussed modeling of pipeline expansion {PPT_7}, which was addressed in greater detail in the 6/17 meeting. He explained that new tariff curves are similar to curves for reservation fees, with an added hurdle rate for expanding capacity. The continuous build-as-you-go approach generally works with the growth of NG demand, but that the inclusion of LNG may cause disruptions and is therefore an important issue to resolve. He referred to the methodology used by the LFMM, using a look-ahead approach to obtain the NPV for capacity expansion. He cautioned that it was important not to overbuild, and that marginal shifts in capacity may be preferable, noting again that pipeline expansion is not a critical part of the model.

Sandy Sanders [SS] questioned the premise that pipeline expansion is not a significant issue, noting that anticipated peak load/duration curves will determine pipeline capacity and storage decisions. This information is important to the extent that it may be possible to defer investment decisions based on future expectations—thus, capacity will influence prices.

[RB] suggested that, given the performance constraints of this model, simpler is better. He approved of the use of hurdle rates and indicated that Mixed Integer Programming (MIP) (discussed in the 9/4/14 workshop) is not a practical approach. The model should permit pipeline expansion to occur if the hurdle rate is achieved, and capacity utilization can exceed 100% with a premium represented by the hurdle rate. This approach permits some flexibility as the hurdle rate may be adjusted to make it more or less difficult to effect "auto-expansion" of capacity.

[JB] inquired as to whether the reservation fees should be reexamined when capacity is added.

[RB] suggested revisiting both the reservation charge and the variable charge when adding capacity, since incremental costs are higher. Capacity will be added based on customer demands and commitments, both upstream and down. In general, he saw no problem with assuming that the marginal value of incremental capacity will be higher.

[JB] then moved on to the interaction between the electricity and NG models {PPT_10}. He noted similarities between the EMM and the NGTDM, and asked if the EMM could benefit from receiving monthly prices for NG rather than seasonal.

[SS] responded that the EMM doesn't need monthly prices as it is a seasonal model. He noted certain differences with the NGTDM, specifically that electric generating units are discrete and clearly identifiable by region, ownership, location, and demands by area; seasonal periods are broken up, and demands are expressed in capacity by the minute.

[RB] responded to a question about possible parallels with electricity generation/distribution, noting that the influence of the government on the marketplace is not insignificant, and that regulations change things a great deal. He further noted that with regard to fuel choice for generation, price competition between NG and coal would not be an effective metric, and further work would be necessary to provide an interface between the NGTDM and the integrated power module. [RB] expressed surprise by the AEO2015 forecasts of gas-powered generation, observing that the build-out of new NG capacity is not particularly high, and noting that the decrease in coal consumption is not matched by increases in NG. He concluded that this was the result of initiatives to increase the use of renewables at the expense of fossil fuels.

[JB] asked whether the NG model factors in electricity generating load shapes. [RB] replied that the model does not get to that level of time granularity; it may be possible to stress-test peak loads, but the model is not particularly equipped to handle hourly swings.

[JB] inquired about the significance of lease, plant, and pipeline fuel issues—whether they should be modeled in detail or could be safely represented by trends, and the consequences of the penetration of electric compression stations on pipeline fuel use. {PPT_12}

[RB] was unsure what the trends are, and was hesitant to offer opinions on the issue other than advising further research of the data and noting that pipeline companies are reluctant to replace NG compression systems with electric units, particularly when there is no scarcity of supply.

[JB] moved on to the treatment of imports and exports {PPT_11}, expressing a desire to have a more detailed representation of Canada and Mexico, but noting that the quality of data is an issue. The Mexican market is changing and it is difficult to anticipate how it will evolve. He asked how to best represent LNG exports in the domestic model.

[RB] indicated that his organization has a template model, where export licenses provide a crude estimate of LNG levels. They are currently developing a global gas model, where LNG import/export trends are based on industry consensus—an unsatisfying approach, but the best they can do with limited data. In this model, Canada and Mexico are represented at the same level of detail as the US, though Mexico represents a challenge for the collection of data. Because Mexico has no open market, pricing detail is inferred, using Henry Hub pricing as a reference. In response to a question about the potential growth in NG-powered generation for Mexico, [RB] observed that Mexican oil reserves are most likely to be developed before NG, suggesting that the penetration of these technologies would be limited.

[JB] directed a question about price-responsive supply and price drivers to [SS], focusing on a comment in the presentation {PPT_13 & PPT_14}.

[SS] in response, suggested that instead of looking at average demand for each moth, attention should be paid to typical daily variations in demand on a seasonal basis, as different sectors will change demand profiles over time.

[PW] noted that pricing matters in the electricity sector because of technology choice with respect to load duration, but that NG is not dependent on production technology.

[SS] argued that pricing is based on capacity utilization, so hourly variation is significant, and may justify keeping track of utilization within a season.

[JB] responded that prices are settled at the end of the day, not hourly.

[AK] concurred, noting that the reservation fee is the charge for a slice of capacity, and this charge can change based on how close the pipeline is to its limit, and depending on whether it is interruptible or core transmission—accordingly, hourly pricing is not a useful measure.

[SS] conceded that the use of daily prices would not affect the validity of the proposed approach.

[RB] suggested that the time scale should reflect the demands of the model, and that the model developers should look for correlations between prices and capacity over the time scale of interest, and the model should ultimately be calibrated to the appropriate time scale.

[JB] briefly discussed the use of average vs. marginal prices, the conditions under which markets equilibrate, and the particular requirements of the EMM. The meeting concluded with a request to consider the appropriate level of aggregation of the model's output, and a suggestion (from Mike Cole?) to have output data dumped into a database to maximize flexibility in future analyses.