August 12, 2013

MEMORANDUM FOR:	JOHN CONTI ASSISTANT ADMINISTRATOR FOR ENERGY ANALYSIS
FROM:	ANGELINA LAROSE TEAM LEAD NATURAL GAS MARKETS TEAM JOHN STAUB TEAM LEAD EXPLORATION AND PRODUCTION ANALYSIS TEAM EXPLORATION AND PRODUCTION and NATURAL GAS MARKETS TEAMS
SUBJECT:	First AEO2014 Oil and Gas Working Group Meeting Summary (presented on July 25, 2013)

Attendees:

Anas Alhajji (NGP)*
Samuel Andrus (IHS)*
Emil Attanasi (USGS)*
Andre Barbe (Rice University)
David J. Barden (self)
Joseph Benneche (EIA)
Terry Boss (Global Energy Group)*
Geoffrey Brand (API)*
Phil Budzik (EIA)
Ron Charpentier (USGS)*
Troy Cook (EIA)*
Yelena Dandurova (SAIC)*
Joseph DiPietro (NETL)*
Michelle Foss (Univ. of Texas, Houston)*
Phani Gadde (Wood Mackenzie)*
Ron Gecan (CBO)
Matthew Gilstrap (INTEK)
Paul Holtberg (EIA)
Ozge Kaplan (EPA)*
Robert King (EIA)
Steven Koptis (Douglas-Westwood)*
Angelina Larose (EIA)
Geoffrey Lyon (DOE)

Phyllis Martin (Phyllis Martin Energy)
Shashank Mohan (Rhodium Group)*
Stuart Mueller (CAPP)*
Chris Nichols (self)*
Olayinka Ogunsola (DOE)
OnLocation*
Bill Pepper (ICF)*
Jack Perrin (EIA)
Gavin Pickenpaugh (NETL)*
Suryan Rajan (IHS)*
Donald Remson (NETL)*
Darryl Rogers (IHS)*
Deborah Rogers (Energy Policy Forum)*
Michael Schaal (EIA)
Ben Schlesinger (BSA)
David Shin (API)*
Michael Scott (EIA)
John Staub (EIA)
John Steelman (NRDC)*
Doug Tierney (EnCana)*
Peri Ulrey (NGSA)
Dana Van Wagener (EIA)
Anthony Yuen (Citigroup)*
Charles Zelek (NETL)

*Attendance via WebEX

Presenters: Joseph Benneche (NGTDM)
Dana Van Wagener (OGSM, EUR)
Phil Budzik (Alaska, CO_2 EOR)
Michael Scott (Drilling Costs)

Presentation:

The presentation provided an overview of the primary assumption changes under consideration for *AEO2014* in the Oil and Gas Supply Module (OGSM) and the Natural Gas Transmission and Distribution Module (NGTDM).

For natural gas modeling the following were presented:

- Benchmarking natural gas prices to average regional historical hub prices
- Endogenously setting U.S. natural gas exports to Canada
- Assumption reassessments for Mexico natural gas consumption and production
- Assumption reevaluations of U.S. and Canada LNG exports
- Distributor tariffs and Canada supply equations reestimates
- Addition of natural gas use by trains and ships in NEMS

For oil and gas supply modeling the following were presented:

- Update of USGS assessments of North Slope shale oil technically recoverable resources (TRR)
- Perspective of North Slope shale oil activities to-date and production constraints
- Lower 48 offshore leasing availability and offshore deepwater projects
- Update of Outer Continental Shelf (OCS) undiscovered TRR
- CO_2 Enhanced Oil Recovery (CO_2 EOR) projects and availability assumptions
- Electricity Market Module (EMM) CO_2 supply interface with the Oil and Gas Supply module (OGSM)
- Onshore Lower 48 dry shale gas and tight oil production
- Modified drilling cost equations
- Estimated Ultimate Recovery (EUR) from continuous plays
- Guarding against conservative biases (blind spots)
- County-level EUR analysis
- Side cases and Issues and Focus articles for AEO2014
- Modeling oil and gas tax legislation changes

Questions and answers regarding the NGTDM:

1) Are you modeling natural gas use in trains and trucks as cited by Administrator Sieminski this morning?
   <u>EIA response</u>: Yes, for AEO2014, EIA will add a representation of train and ship use of natural gas; we previously have included trucks and cars.

2) Are you able to track large (unregulated) contracts (1 year contracts)?
   <u>EIA response</u>: EIA recognizes that a large portion of natural gas is sold through long-term contracts. However, marginal prices drive the marginal demand that is used in the NEMS, a supply/demand equilibrium model.

3) What is the amount of gas sold through contracts?
   <u>EIA response</u>: EIA doesn't track the amount of natural gas sold through long-term contracts.

4) Is the EIA change in modeling Canadian LNG exports correct? (EIA question)
   <u>Working group attendee response</u>: EIA’s treatment of Canadian natural gas is correct, including its treatment of LNG and stranded Canadian gas.

5) As recently written in the paper, how do you deal with international competition, i.e. Siberian gas to China.
   <u>EIA response</u>: LNG build decisions are not necessary made from a holistic world natural gas market viewpoint. Builds will depend on representative Asian and European natural gas prices, as compared to a FOB U.S. LNG price. The EIA representative Asian and European price model includes production, the size of the global LNG market and regional production/consumption.

6) How does EIA model LNG international competition?
EIA response: Both international supply and demand estimates, as well as, costs differentials are needed to model international LNG changes. For AEO2014, EIA is updating data for its profile of world LNG based on recent LNG investments and decisions by major producing and consuming nations, as well as with data from EIA's recent International Energy Outlook supply and demand projections.

7) At what natural gas price does exporting LNG from U.S. LNG export terminals become uneconomical?
EIA response: EIA assumes that when a project is built, it will run at capacity for the projection period. EIA does not assume a price point that would prohibit exports from a facility that has been built in the model. Natural gas prices are just one input variable needed to estimate domestic LNG export investments. LNG exports are modeled based on economics over the cost recovery period of the project.
Working Group response: Unless the market implodes, once a facility is built, it will be running at capacity.

8) How are LNG facilities modeled?
EIA response: Last year, LNG facilities builds were modeled endogenously. For AEO2013, North American LNG facility builds were also limited to one per year. For AEO2014, EIA is relaxing this constraint for build rates, allowing Alaska and Canada to operate as separate entities. Additionally, this year, EIA will also assume trains 3 and 4 of Sabine Pass will be built based on contracts in place. Additionally, EIA will exogenously set Canadian LNG export terminals based on the IEO projections.

9) How will prices of international LNG be modeled?
EIA response: EIA models representative European and Asian natural gas prices that change in relation to the oil price as more "flexible" LNG enters the market. NEMS, although it is mainly domestic, represents these international prices. EIA is in the process of enhancing its international model to provide more dynamic world cases for consideration.

10) Is all the gas (going for LNG) dry or is it about 20% ethane?
EIA response: The implicit model assumption is that we are only exporting dry gas as LNG as we are really only modeling the domestic market for dry natural gas within the Natural Gas Transmission and Distribution Module. While we are estimating the levels and value to the producers of natural gas plant liquids within the upstream model, the processing and marketing of the component products is handled separately within NEMS and therefore as a distinctly separate market from dry natural gas.

Questions and answers regarding the OGSM:

1) How are crude oil prices determined?
EIA RESPONSE: Domestic oil prices are estimated based on a supply/demand equilibrium, and are linked to the three exogenously estimated global oil price paths.

2) How does the model treat the non-homogeneities of world oil prices?
EIA response: The model uses a reduced representation of world oil prices to account for crude type and location. The level of detail is determined by the model's ability to mimic the market dynamics to world oil price differences.

3) Is there an effort to change the Reserve Report survey form to obtain county-level data such as in North Dakota?
EIA response: No changes to the EIA 23 survey. However, EIA is in the process of increasing the fidelity of production data to better estimate the potential of the play. Currently, the model characterizes plays within a state into just 3 EURs - the top 15%, the bottom 15% and the 70% middle. For AEO2014 we plan to use 1 EUR for each county of a play.

4) Is there a published analysis showing the relationship of oil-in-place to technically recoverable?
EIA Response: EIA has published several oil estimate articles and reports such as the recent publication "Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States" summarized at *http://www.eia.gov/analysis/studies/worldshalegas*/.

5) What is the level of production well information EIA is using to project future production?
EIA response: EIA use publicly available drilling databases, company surveys and evaluates the well performance by vintage, county level, changes in well length and number of frac stages.

6) Has EIA written a white paper on EUR analysis?
EIA response: The Annual Energy Outlook 2012 included two "Issues and Focus" articles on EUR analysis (http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf).

7) EIA question: EIA is considering moving away from distinguishing between "shale gas" versus "tight gas" labeling for low permeability plays because many low permeability plays are a mix of rock types. The important feature of the play is the production method which indicates the permeability.
Stakeholder response: No problems raised.

8) How is EIA handling the uncertainties of the 3-D shape of the formations and the physical boundary in estimating technically recovery oil?
EIA response: EIA attempts to remove as much uncertainty as possible in the drilling information as it relates to defined formations. This includes the uncertainty in the

boundaries of the adjacent/overlying formations. For example, the Bakken-Three Forks is often labeled as merely "Bakken" rather than separating out the Three Forks formation.

9) Are people drilling horizontally into deeper layers?
EIA response: Yes and no. Drilling strategies vary as drilling knowledge is gained for a play. It's about moving to the most profitable layers. Some drilling plays evolve into deeper drilling, while others move into shallower ones. We see testing of the Three Forks benches, but industry is at early stage.

10) How does EIA put out its modeling assumptions and get discussions going?
EIA response: EIA publishes its assumptions annually at http://www.eia.gov/forecasts/aeo/assumptions/, where it splits out the information by each NEMS module. For the oil and gas assumptions, we hold two working group meetings and we reach out to the oil and gas industry and discuss these assumptions with the companies involved. EIA recognizes the need to maintain confidentiality and understands the limits of the companies' comments. All discussions are tied to well productivity. For example, the Buda formation, which underlies the Eagle Ford formation, has a just few scattered wells. And in the Monterey formation, estimates based on the oil-in-place method have not materialized. The evolving understanding is that the oil may have moved out of the Monterey due to faulting.

11) The independent oil companies are driving the shale and tight oil drilling. Are there enough driven producers to keep it going?
EIA response: EIA continues to monitor exploration and production drilling activity and investigates the trends in terms of activity, cost, and annual production. If the industry continues to have success, it is expected that the industry will grow as market opportunities dictate. Single no single well is guaranteed to produce economically, the drilling decision is an educated one, based on a monetized assessment of risk versus reward. For example, an operator in the Bakken drilled two wells, one went horizontally to the west of the surface location and produced at 1000 barrels of oil per day (bopd), while the other went horizontally to the east and produced less than 100 bopd. The maturity of the play will include both the use of tighter well spacing in known "sweet spots" and the expansion of exploration and production into less productive areas.

12) How does EIA estimate the near-term future of these plays?
EIA response: Near-term forecasts are informed by drilling activity trends, drilling efficiency trends, backcasting using near-term exploration and production history and analyst knowledge of play activity.

13) Is there a side case for the Bakken?
EIA response: There are side cases on resource assumptions that include EUR and well spacing changes to the Bakken and all of the other low permeability plays.

14) When will you know if production will drop due to a decline of drilling?
EIA response: In 2008 as gas prices dropped, drilling counts started to head down. Total decreases in oil and gas production will occur when the economics of the investment result in insufficient drilling to replace the net production declines of existing wells. Those economic conditions are affected by the geology, technology, and economy. EIA monitors all three of these factors and adjusts the model to reflect measured changes.

15) Why are the EURs of wells in Bradford County, PA better than those in SW Pennsylvania?
EIA response: It depends if you are looking at just gas or both gas and liquids. Current production data from these two areas are used to estimate the well EURs. As time passes, these estimates will improve as more production data is provided and the EURs will change over time, perhaps showing different comparative performances.

16) Does EIA see a big overall production difference over time?
EIA response: No, production appears to continue provided the economics are favorable. We have not identified any step change due to technology or resource discoveries.

17) Do you see any proxies for estimating field production?
EIA response: We do look for proxies to improve our estimating capabilities. Currently, we are switching to county-level modeling where we may see production changes more quickly.

18) Any evidence of restimulation of wells?
EIA response: Yes, we have seen restimulation of wells, which appear to mostly recover oil sooner, increasing the net present value of the well.

19) Is EIA modeling deep Bypassed Residual Zone and its effect on CO_2 demand?
EIA response: Although a potential resource, at this time, too little is known about Residual Zone Oil to permit its modeling in OGSM.

20) How is CO2 Enhance Oil Recovery (EOR) analysis coordinated between EIA, NETL and other groups?
EIA response: There is ongoing interaction with group in and outside of the government on CO2 EOR. EIA proposed organizing a workshop in September or October, which would bring in outside speakers (such as NETL, USGS, industry) and facilitate a discussion of the potential of industrial and electric power generation capture of CO2, and the amount of additional oil that could be produced.

21) Does Alaska versus Lower 48 well costs depend on productivity?
EIA response: Productivity, prices and costs determine the return on investment. The oil and gas project must also be risk rated to effectively determine its competitiveness.

22) What is the distance of the Great Bear tight oil well test area from TAPS?
EIA response: One well is off the Dalton highway, the play ranges up to approximately 100 miles from the Dalton Highway on both sides.

23) EIA made a great case for zero oil from the Alaska shale by 2040. Is the shale on state land?
EIA response: Yes, to date, all the Alaskan shale leases granted are on state land.

24) What coordination is done with BOEM on technically recoverable resource estimates used in NEMS?
EIA Response: BOEM provides EIA with the underlying field-size distribution for their resource assessment. EIA subtracts the number of fields that have been discovered since the latest assessment data cutoff (the BOEM 2011 assessment used data as of 1/1/2009). Also, the list of announced discoveries is provided to the BOEM for comment.

25) When will you update your estimates?
EIA response: TRRs will be updated by the end of August 2013. CO_2 numbers have not been updated. However, EMM and the CO_2 environmental role has been incorporated into NEMS to provide additional industrial CO_2 for EOR if cost effective.

26) Why are drilling costs modeled on American Petroleum Institute's (API) 2007 Joint Association Survey (JAS) data?
EIA response: More recent JAS data appear to represent less of the industry, cost more and API has altered their product to make it less useful from a modeling perspective. The 2007 drilling cost data, while not ideal, is the most comprehensive we have and is sufficient to develop cost terms that reflect the dominant cost drivers to drilling oil and gas wells.

27) Does this cost equation make sense in light of the wide cost variations in the data?
EIA response: Yes, the cost equation is an estimate of the drilling and completion cost by location, depth, and well type. The model uses the drilling cost, along with other well costs, to rank order the net present value of the investment in all potential wells. This method enables total drilling activity to be estimated by region and year. The new equation merely aligns the cost terms to real world cost drivers. A statistical approach would not provide a "better" cost estimate for the model. The rank ordering of the potential wells creates the distribution of wells needed to emulate drilling decisions. The model is attempting to emulate a market behavior not estimate the cost of a particular project.

28) Is EIA doing the same for offshore drilling costs?
EIA response: We will not change the drilling cost equation for the offshore in AEO2014.

29) Is the drilling cost problem variability?
EIA response: The model is not trying to model the variability of costs but the behavior of the industry in determining where, when and how much to drill. There is no added value to modeling D&C cost variability since the variability of other cost components not available such as the variability in the costing of risk among different drilling companies. EIA does run sensitivity cases based on cost.

30) Do you see a change in costs due to rig activity?
EIA response: We analyze the rig activity effect and only see correlation when rig counts start approaching historical highs. We are also assessing rig type switching effects on drilling cost. Historically, the dominant well cost indicator is oil price. Other cost drivers include technology adoption and learning.

31) What about marginal wells cost credit?
EIA response: There are two enhanced oil recovery credits: one sunset at $30 per barrel, and the other is the 45Q gas enhanced oil to cover CCS cost.