July 22, 2013

MEMORANDUM

TO: John Conti
Assistant Administrator for Energy Analysis

Alan Beamon
Director, Office of Electricity, Coal, Nuclear, and Renewables Analysis

FROM: Coal and Uranium Analysis Team

SUBJECT: AEO2014 Coal Working Group Meeting I Summary

Attendees (41)

Name	Affiliation
Greg Adams (Moderator)	US DOE: EIA
Vlad Dorjets	
Bob Eynon	
Karen Freedman	
Tyler Hodge	
Paul Holtberg	
Elias Johnson	
Ayaka Jones	
Diane Kearney	
Mike Leff	
Mike Mellish	
Carrie Milton	
Nick Paduano	
Margaret Cook	US DOE: HQ
Dave Schoberlein	US DOE: HQ
Sikander Khan	US DOE: FE/HQ
Jose Benitez	US DOE: FE/NETL
Christopher Nichols	US DOE: FE/NETL
Gavin Pickenpaugh	US DOE: FE/NETL
Erich Eschmann	US EPA
Brian Fisher	US EPA
Cortney Higgins	US OMB
Greg Moxness	US DOL: MSHA
Maria Distasio	US DOL: MSHA
Carl Lundgren	US DOL: MSHA
Paul Pierce	US DOI: USGS
Leslie Coleman	National Mining Association
Paul Georgia	National Mining Association
Jeremy Richardson	Union of Concerned Scientists
Glenn Stoner	Colorado Springs Utilities
Carolyn Evans	Norfolk Southern Corporation
Natalie Biggs	Wood Mackenzie
Greg Marmon	Wood Mackenzie
Salem Esber	PA Consulting Group
Jamie Heller	Hellerworx, Inc.
Charlie Mann	Energy Investors Advisors, LLC
John Scmitter	KEP LLC
Seth Schwartz	Energy Ventures Analysis, Inc.
James Staudt	Andover Technology Partners
Boddu Venkatesh	ICF International
Jack Ried	Seminole Electric Cooperative, Inc.

Comments on the Carbon Adder and Regional Haze

Several participants sought clarification of questions pertaining to the 3 percent adder to the cost of capital for coal capacity additions and retrofits, including the applicability of the adder to emission control retrofits, how the adder affects the cost of capital, the basis for the 3% value, and the impact of the adder. EIA staff clarified that the adder does apply to retrofits associated with MATS compliance but does not apply to carbon capture retrofit equipment. Staff also confirmed that the adder would increase the overall cost of capital on a hypothetical basis from 12 percent to 15 percent in the model, and that the original concept was derived from the "Carbon Principles" put forth by the financial community several years ago. Staff also noted that the 3 percent value is roughly equivalent – when levelized – to about $15 per ton of carbon dioxide, which generally corresponds to values many utility planners appear to be assuming in their planning decisions. Staff referred participants to the No Greenhouse Gas Concern case that removes this additional cost and the model projects more retrofits of FGD scrubbers, less dry sorbent injection (DSI), and additional coal plants.

One participant noted that EIA might consider dropping the 3 percent adjustment in future years once EIA begins modeling the proposed performance standards for coal plants. **EIA will follow up on this issue during the review of AEO2015 assumptions once more is known about the EPA NSPS regulations.**

Another participant asked if the model includes assumptions regarding the western region BART/regional haze regulations. Staff responded that while the regulations are not explicitly covered, any planned retrofits at affected plants associated with regional haze are included to the extent they are reported to EIA on their survey forms.

Comments on Planned Capacity Additions

Staff confirmed that the planned coal units for AEO2014 have been reported to EIA as under construction and are the same as in AEO2013. Several participants commented on the status of specific planned capacity additions.

- <u>Two Elk Power Plant</u>: One participant suggested excluding this plant since it has been 'under construction' for ten years, and that although the plant has acquired its air permit, the company is required to satisfy very minor construction requirements in order to maintain it. Staff mentioned that EIA did contact the owner of this proposed plant last year, and the owners continued to regard the plant as 'under construction' at that time. **The plant will be included in AEO2014.**
- <u>Spiritwood Plant</u>: One participant noted that the latest start date for this plant is 2014 with a capacity of 99 MW, rather than the 62 MW assumed by EIA. Staff responded that the plant appears to have secured a purchase power agreement for 62 MW. The participant replied that since the plant is a cogeneration plant, if EIA is only accounting for the electricity portion of the capacity, then the 62 MW capacity value could be correct. **Staff will attempt to verify the contracted value.**
- <u>Taylorville</u>: One participant noted that this plant was recently cancelled by Tenaska. **Staff will follow up to verify this outcome.**
- <u>Medicine Bow</u>: Staff inquired about the size of the Medicine Bow coal-to-liquids (CTL) facility of 350 MW. One participant questioned whether the plant planned to sell electricity to the grid, to which staff responded that the capacity should include both electricity sold to the grid but also electricity for self-use. **Staff will attempt to verify the share to be sold to the grid.**

One participant noted that other CTL facilities should not be forced into the model despite the numerous press releases regarding such facilities.

Illinois Basin Coal Projections (vs. Northern Appalachia)

Several participants raised concerns about EIA's projections for production from the Illinois Basin being too low based on their expectation of low prices for the commodity relative to coal from other regions and ample reserves, even as overall coal demand grows relatively little through 2040. Participants noted that plants in the Southeast have recently increased their purchases of Illinois Basin coal and that the region's production could be expected to accommodate an additional 30 million tons per year of sustained production within the next 5-10 years.

The participant then asked if there were limiting factors incorporated into the model with respect to Illinois coal. Staff responded that the model is not modeling chlorine or sulfur restrictions for Illinois Basin, but noted the possibility that some of the model's transportation rates could be inadvertently prohibiting Illinois Basin growth. **Though the staff is not currently aware of any specific limiting factors, they will review the model to identify any potential problems.**

Concerns were also raised about the general ability of production from Northern Appalachia to increase by the amounts in forecast in the AEO2013 projections. One participant wondered where the growth in Northern Appalachian coal could be attributed and stated that the Pittsburgh seam is fundamentally different in its cost structure, and it might even have difficulty sustaining its current levels of production. The participant stated that the productivity trends are not consistent with the production trends in the AEO2013 for Northern Appalachia and Illinois Basin. Another participant noted potential limits with regards to the geology and the adequacy of the resource base. The participant also commented that the effects of depletion has been outpacing technology trends have been moving in opposite directions in some basins including the Powder River Basin, and that longwalls in the Illinois Basin have resulted in improvements.

Staff commented that the model may be opting for Northern Appalachian coal as opposed to the Illinois Basin, and the two potential problems may be related. Staff mentioned that we do have a relatively negative outlook for productivity in the Northern Appalachian region though not as pessimistic as Central Appalachia, and for Eastern Interior (Illinois Basin), we have the most optimistic assumptions. **Staff will closely review our transportation rates and productivity assumptions for these two regions.**

Staff also acknowledged the large increase in longwalls in Illinois and wondered if anyone had any thoughts regarding the use of longwalls in other states in the Illinois Basin. One participant stated that the need for large contiguous blocks of coals means that this is a technology that will mainly be used in Illinois. Another participant concurred stating it is very unlikely that western Kentucky or Indiana will use longwalls, and that the depth of cover (overburden) is really the biggest issue as well as the size of the reserve. The participant also mentioned that the limited use of longwalls in these other states has less to do with seam thickness and that this does not mean other technologies will not be employed.

Aging Coal Fleet Performance and Replacement

One participant raised a concern regarding high coal capacity factors with a coal fleet whose average age is 60 years. The participant acknowledged that EIA models higher O&M costs for its aging coal fleet but wondered if more new replacement capacity may be required to meet future demand. In response, another participant disagreed stating that there is no real reason that older units cannot support higher capacity factors, but that another problem may be the interaction of coal plants with a larger renewable portfolio – in particular wind. The participant explained that since wind runs harder in the off-peak periods, coal may expect to be displaced at those times. Staff commented that currently EIA staff is looking at updating the spinning reserves methodology in order to handle the intermittency issues.

Metallurgical Coal

One participant suggested that even though it has labor and other cost issues to contend with, Australia is geographically and geologically better-suited to supply international coking coal markets than the United States and thought that U.S. coking coal exports should decline over the projection rather than holding steady as Central Appalachia's coking coal reserves have high production costs. Staff commented that a lot of Northern Appalachian coking coal is currently exported, and asked for comments regarding the quality of coal as a consideration since many coking coal consumers regard U.S. coal quality very favorably. No feedback was provided on this question.

One participant responded by stating that it was very important to make some sort of assumption regarding the future exchange rate even if it is an assumption that does not change, acknowledging that EIA would probably need to use some sort of official projection of exchange rates if one existed. Staff stated that exchange rates are not currently considered in our modeling of international coal trade, and that exchange rate projections are probably not available from the NEMS macroeconomic model.

Side Cases

Staff highlighted that EIA's side cases in the AEO2013 include greenhouse gas cases and mentioned that we see the carbon capture technology preferred for natural gas plants before coal plants in these cases. One participant asked if EIA is still assuming that pulverized coal plants with carbon capture technology are cheaper than IGCC plants with carbon capture to which staff replied affirmatively. Staff also responded to an inquiry regarding nuclear capital costs stating that nuclear costs are assumed to be about $5400/kW. The participant stated that these costs are based on brownfield sites and asked if staff regard these costs to be appropriate in the $25 carbon price case. Staff replied that we still think these costs are valid assumptions.