August 17, 2016

MEMORANDUM

TO: Dr. Ian Mead
Assistant Administrator for Energy Analysis

Jim Diefenderfer
Director, Office of Electricity, Coal, Nuclear, and Renewables Analysis

FROM: Coal and Uranium Analysis Team

SUBJECT: Notes from the **Coal Fleet Aging Meeting** held on June 14, 2016

Attendees (36)

Name	Affiliation
Greg Adams	U.S. Energy Information Administration
Jose Benitez	National Energy Technology Laboratory
*Jay Ratafia-Brown	Leidos
Kara Callahan	On Location
*Ivan Clark	Leidos
*Eric Crews	Leidos
Jim Diefenderfer	U.S. Energy Information Administration
Brian Fisher	U.S. Environmental Protection Agency
*Sarah Forbes	Department of Energy
Kristin Gerdes	National Energy Technology Laboratory
*Matthew Greek	Basin Electric Power Cooperative
Don Hanson	Argonne Laboratory
Tom Hewson	Energy Ventures Analysis, Inc.
Thaddeus Huetteman	U.S. Energy Information Administration
*John Jacobs	Basin Electric Power Cooperative
Ayaka Jones	U.S. Energy Information Administration
*Jeffrey Jones	U.S. Energy Information Administration
*Serpil Kayin	U.S. Environmental Protection Agency
Diane Kearney	U.S. Energy Information Administration
*Augustine Kwon	U.S. Energy Information Administration
Laura Martin	U.S. Energy Information Administration
*Gavin McCollam	Basin Electric Power Cooperative
Chris Nichols	National Energy Technology Laboratory
*Mason Douglas Palmer	Leidos
Rick Roberts	Electric Power Research Institute
Sandy Sanders	On Location
Dave Schmalzer	Argonne Laboratory
*Michael Scott	U.S. Energy Information Administration
*Michele Somerday	First Energy
Ann Stasangi	Department of Energy
*Ken Walsh	Leidos
*Larry White	Mitsubishi Hitachi Power Systems
*Robert Wilson	First Energy
Frances Wood	On Location
Thomas Wos	Tristate Energy
Charles Zelek	National Energy Technology Laboratory

*Indicates attendance via WebEx.

Framing the question

This adjunct meeting of the AEO Coal Working Group (CWG) was held as a follow up to the previous *Future Operating and Maintenance Considerations for the Existing Fleet of Coal-fired Power Plants* workshop held on June 16, 2015. The purpose of the meeting was to guide next steps and priorities for tangible research initiatives or focused modeling efforts that (1) address issues associated with operating an aging coal fleet and (2) can be represented in the Electricity Market Module of EIA's National Energy Modeling System. Three participants were invited to provide presentations to help frame the discussion. These presentations are available on the CWG website for the meeting:

- Chris Nichols, National Energy Technology Laboratory (NETL), *Characteristics of the Coal Power Plant Fleet*
- Laura Martin, U.S. Energy Information Administration, *Current Electricity Market Module Methodology for Coal Power Plant Modeling*
- Tom Hewson, Energy Ventures Analysis (EVA), *Power Company Investment Decision Making*

The presentations were followed by discussions with participants to identify meaningful areas for further research that could be undertaken by EIA or other organizations to better inform modeling.

NETL presentation and discussion

NETL's interest in the status of the existing fleet lies partly in their R&D efforts for carbon capture and sequestration (CCS) retrofits. The viability of future retrofits rests partly on the strength of the remaining fleet.

There is a relationship between retiring units and the manner that the units are being operated. In other words, many retirements have been preceded by operation for some period of time in a sub-optimal utilization range.

NETL calculated that forced outage rates have gone up to 7% when plants are cycled compared to 3% for baseload operation. Cycling units more frequently increases the probability of catastrophic failures.

The duration of forced outages is something worth looking at.

NETL identified a lot of little problems that add up to bigger issues including boiler tube corrosion, waterwall web cracking, casing failures, and creep. 'Creep' refers to the operation of a plant within the design specifications of a metallurgical material – but at the edge of those specifications and at a medium to high frequency – that ultimately contributes to the material's failure. The combination of time, temperature, and stress applied to this material contributes to 'creep.' The more chrome there is in metals, the greater protection against creep.

Don Hanson's ESIM model uses a damage score assignment – as a proxy for the engineering cost and diminished performance -- to convert cycling activity into a decision to retire. When a plant reaches a certain number of accumulated points (e.g. 300), which are applied incrementally at every instance of suboptimal operation (e.g. cycling at sub-optimal levels), the plant retires. Minimum unit commitment was taken into account. Someone asked if the cycling profile was tied with other factors such as seasonal factors. While the answer is currently no, this could be an opportunity for altering the algorithm in the future. Three causes of coal plant cycling include more renewables, low gas prices, and a real or shadow price for carbon. Someone asked if it was possible to separate the effect of the damage function and the carbon policy, to which the answer was 'yes'. Renewable production tax credits are also a factor contributing to cycling of coal plants.

A report on cycling is due out from NETL in August.

Electricity Market Module (EMM) presentation and discussion:

The presentation included a general description of how the electricity market model works: Electricity demand is sent to the electricity model from the other models. Load curves are developed. The Electricity Capacity Planning Module (ECP) then solves one time for each year in order to determine generating unit builds in the following year. To make this decision the ECP looks out 30 years as capital costs must be recovered within that timeframe. The Electricity Fuel Dispatch Module (EFD) has a greater level of detail for the plants and calculates generation and fuel consumption levels. The EFD solves one year at a time but solves multiple iterations within a year as inputs from other models change. The Electricity Pricing Module (EPM) calculates retail electricity prices.

Fixed and variable O&M were updated via FERC Form 1 for AEO2014. Since many plants do not report on this form, a statistical analysis was performed to fill in the information gaps.

Annual capital additions for existing plants are modeled as fixed O&M expenditures that are above normal maintenance but not at the level of a retrofit. This is an area that is in need of updating. The 3% cost of capital adder applied to retrofits and new coal capacity to represent the added risk associated with a coal plant investment is not applied to the annual capital additions.

The addition of emission control equipment (retrofit) includes the overnight costs as well as the O&M. When a plant retrofits, it changes the plant type designation in the model. When this occurs, its O&M adder changes as well.

Every coal unit has an input maximum capacity factor based on historical data (five-year average) and a floor of 60%. If this input is below 75%, the plant's maximum capacity factor in future years is assumed to increase over the first few years of the projection period until it reaches 75%. Coal units with input capacity factors above 75% may operate up to their input capacity factor in any given year of the projection.

There is an annual capital cost adder based on the age and type of unit (coal, oil/gas steam, and nuclear). Once a plant reaches 30 years of age, a one-time age adder is assessed and then held constant over the remaining projection years as described in the presentation. Only a retrofit or age adder changes fixed O&M costs for a plant over the projection horizon. Otherwise, fixed O&M does not change.

The EMM does represent seasonal NOX.

The Clean Power Plan is modeled based on the 22 regions represented in the model. Most regions include multiple states. Via this aggregation, states are implicitly assumed to cooperate in meeting the requirements of the CPP.

The transmission costs modeled are the costs incurred to interconnect a plant to the grid. The full cost of maintaining the grid is not represented in the LP programs.

New construction is financed using 45% debt and 55% equity with a time horizon of 30 years. The exact rate depends on assumptions from the macroeconomic model.

Retrofits are modeled with a payback assumption of 20 years and the cost of capital is based upon the regulated costs of capital for that region whether or not the plant is an independent power producer (IPP). In general, the regulated discount rates are lower than deregulated discount rates.

If a coal plant is not needed to meet the reserve margin, the plant is losing money in a single year in the EFD, and the ECP agrees that it is not needed over the projection period, the plant is retired.

Annual demand is broken down into three seasons of three time slices each (nine total). The peak represents 1% of the hours in a season, intermediate load represents 49% of the hours, and baseload represents 50%.

One participant asked if the representation of nine load slices was new. The response was that this representation is not 'new' but also was not the original representation in the EFD. Within the past decade, test runs were made that indicated a reduction in time slices did not appreciably change the answer coming from the model. It was mentioned that the possibility exists that power generation has changed enough in recent years that the use of fewer load slices may no longer adequately represent the markets.

Coal units are not allowed to be used just for the peak load slice. Coal units can operate in 'load-following' or implicitly cycling modes to provide spinning reserves and not generate at full load in all time slices.

One participant commented that specific unit detail is important when discussing cycling. The EFD almost models unit by unit. In a few cases, several plants may be put together because they are identical in all relevant characteristics being modeled. The ECP commits individual units for power production but aggregates them in the 32 plant types for dispatching.

The plant groupings present in the model are based upon different configurations and combinations of retrofit equipment at a plant and were designed as such in an effort to model mercury emission reductions.

On Location, on behalf of EIA, is conducting a heat rate study, gathering more data to determine the relationship between heat rate and output level/operating mode so that NEMS can ultimately model alternate heat rates based on operation. The study will expand beyond an earlier report that was based on only 35 plants.

One participant commented that only a small change in heat rate should be attributable to cycling variations.

The model does allow heat rate to improve if an associated investment is made.

One participant commented that the cycling issue is really a cumulative process. The impacts of cycling may not be seen in the current year of operation but much later.

Tom Hewson/EVA presentation and associated comments:

EVA has moved away from a linear programming methodology and now uses the Aurora Economic Dispatch Model. Within that model, heat rates vary by utilization.

Power companies are looking at what is happening now and what is likely to occur in the future in assessing their risk when they conduct their Integrated Resource Planning (IRP) processes. IRPs look at what's going on with all assets – i.e. what is best in aggregate, taking into account the many financial, market, and regulatory constraints discussed in the presentation. Financial risk varies significantly by ownership types – IPP, regulated utility, rural/publicly owned.

Assessing cost and risk is some function of age, heat rate, technology, and the type of coal burned. In assessing payback, EVA looks at the remaining lifetime of the unit rather than assuming 30 years.

EVA has found that it had to limit some of the minimum capacity factors for plant units to account for ramping requirements. Curtailment of renewables and zero-cost transmission assumptions are also examples of how an economic model may not be sufficient to address the increase in intermittent generation.

There are at least 30 types of coal, each with its own associated costs in the EVA model.

The nuclear retirement impact on fuel markets is potentially huge.

EVA's model includes end-of-life assumptions and takes into consideration the impacts of intermittency on cycling. However, EVA's model does take the number of cold starts and stops into consideration within its modeling framework. Intermittency's impact on baseload units is expected to be a bigger issue for off-peak wind than solar.

Accurate modeling requires consideration of climate and regional issues. For instance, if a coal unit is not going to run in the summer time, it will not retrofit to meet the NOX seasonal limits. Units in the northern U.S. may opt to retire rather than run only seasonally.

One participant commented that EPRI studies have indicated that certain retrofit equipment can still operate effectively at levels lower than what is stated [by the manufacturer].

General discussion

(The following represents individual comments and discussion that occurred at the meeting and may or may not be the opinion of the entire group in attendance.):

One participant commented that electric generating companies do not use models to make decisions. They use models to inform and support decisions.

One participant expressed interest in looking at the nuclear industry's use of integrated lifetime modeling where a similar application might be used for coal.

One participant stated that though the costs are real, the cost of damage to a particular component is difficult to quantify, and every cycle has some impact.

Operating temperature has greater impact on the equipment than the frequency of cycling.

Some of the limits given for loads for NOX controls are not true. For example, an SCR whose stated capacity is 700 MW, has been shown to effectively operate at 500 MW with no impact on emissions reduction potential.

Some Wyoming coal plants are consistently run at 90% utilization. Every plant is different.

EPRI and Aptech Engineering have performed coal data work, but, in general, we do not have enough data to fully assess the costs associated with age/cycling.

One participant commented that the identification of starts and stops is important.

Starts and stops are more damaging to equipment than cycling

One participant advised that using another more detailed hourly dispatch model may provide insights for the characterization and modeling assumptions within EMM.

Given enough money and investment, degradation issue can be addressed and coal plants can continue operating.

When asked if companies' financial strength would affect decisions to put up the lump sum of money needed to continue operation of a plant, a few participants commented that they will invest regardless of the strength of their balance sheets as long as it's economic to invest.

One participant commented that EPA's assumption about heat rates is too optimistic, and it would cost the industry $7 billion to improve heat rate by 1.1%. Efficiency improvements were the low hanging fruit, and there is little additional room for improvement in this area.

The concept of the lumpy investment versus the gradual yearly cost is an important one to represent in the model. By modeling aging/cycling costs as a retrofit, EIA may better represent the costs and manner that plants incur those costs.

Because of cycling, it will cost more to keep a plant operating.

If a company has plans to retire a unit/plant in 8 -10 years, it will stop putting money into the unit/plant. For announced retirements, EIA should consider showing a degradation of investment levels.

Determination of when aging/cycling costs should be incurred is an important aspect of the modeling.

One participant suggested picking key time frames at which large annual costs could be incurred, much like the cost of adding a SCR. The plant might make such an investment or be forced to retire.

The year that an environmental regulation hits is an appropriate time for a plant to do an overall lifetime assessment -- including anticipated large costs for aging/cycling – to determine whether the plant should retire or not, and make the aging related investments.

An important consideration is the overlap in impacts. There could be the potential to overstate impacts where a cycling impact primarily impacts O&M but is also assumed to impact heat rate.

Cycling in the current year affects the heat rate in that year but the cumulative impact is really felt on O&M.

EPRI has conducted research in the area of cycling of fossil generation assets. The report "Descriptions of Past Research; Impacts of Cycling on Existing Assets summarizes the research done through 2012 by EPRI's Generation sector and is free to the public.

An attempt to characterize the data (heat rate, O&M, mode of cycling) and establish relationships among the data could be an important next step for EIA.

Some plants operate with high heat rates but are not expected to retire; older plants tend to have higher safety margins for operations.

The likelihood of catastrophic events – boiler or turbine failure – although detrimental to a plant have a lower probability. A catastrophic failure that is not represented in the EMM would have minimal impact on the overall projections. Therefore, EIA should concentrate its costing effort on the numerous smaller, but still expensive costs that are more likely to be incurred by a plant over time.

Because of low levels of cycling, some plants bypass certain plant functions, and this will have a long-term impact on plant costs.

One participant suggested that the period of time, e.g. 5 years, in which cycling occurs is an area of study. Unless a plant is really worn out and has not been properly maintained, the problems with cycling will not show up yet. Cycling will affect the reliability of the plant and cost of repairs more than the heat rate. Post-combustion controls and boiler type make a difference, and starts/stops have more of an impact than ramping up and down. 30% was noted as the absolute lowest operating range for a coal unit.

One participant recommended that EIA start with a simple assessment of existing data (heat rates, generation, O&M) and work with the existing structure of the model. Costs have not otherwise been accumulated in a manner to facilitate deep analysis of cycling/aging.

One participant expressed the importance of discerning the correlations between factors such as heat rate, capacity factors, and O&M costs within the data.

Another participant inquired as to whether the discussions on coal-fleet aging would apply generally to steam plants generally.

There are a few coal plants operating in the United States that were designed to cycle. Materials used as part of their design and construction enable those plants to withstand the demands of operating in a cycling mode. .

Natural gas combined cycle plants can have similar cycling issues and this shouldn't be ignored. They are also not designed to last as long as coal plants, and aging issues should be considered for them as well.

There could be a reduction in cost over time as experience is gained in dealing with aging/cycling related costs. The industry may learn to cycle its coal plants with fewer detrimental consequences over time.

Engineering consultants that have experience with creep issues and estimating remaining life for plants include Aptech Engineering, Structural Integrity Associates, and Thielsch Engineering.

Some EPRI research includes conditional based maintenance, continued online monitoring of equipment, and advanced pattern recognition that allows for quicker detection of degradation.

Germany has more experience with supercritical technology over the last 15 years.

A Leidos participant mentioned a previous study on O&M performed for EIA.