The Role for Baseload Generators in Optimized Electric Power Systems

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Overview

Existing fossil-fuel and nuclear baseload electric power generators are struggling under current market conditions. And as a result there is little appetite for investments in new advanced fossil or nuclear technologies. One needs to consider whether this situation is desireable or whether it will likely be costly over the medium- to long-run. The causes of coal and nuclear retirements are both financial and physical. These units were not designed for load-following and cycling [EPRI]. Load-following and cycling may result in inadequate revenue to cover costs going forward and likely results in increased operating and maintenance costs, and eventually major equipment failures. This presentation shows results from an electric power system model which simulates the near- and long-term consequences of merit order dispatch and resulting replacement investments. The model can represent the impacts of projected expansion of wind, solar, and natual gas combined cycle (NGCC) generation on the operation and eventual replacement of baseload units. We then converge the model for a least-cost present-value solution to meet electicity demand while achieving a hypothetical constraint on cumulative CO_2 emissions. We learn that too rapid retirements of existing baseload capacity is non-optimal; it leads to large investments in NGCC, a delay in the adoption of advanced baseload technologies (which are part of the long-run generation mix), and higher gas prices.

Methods

For this analysis we use the Electricty Supply and Investment Model (ESIM). ESIM contains a unit inventory of existing coal-fired power plants greater than 50 MW. In addition there are 30 other generation technology categories including seven new or retrofitted coal-based technologies and two advanced natural gas technologies with carbon capture (i.e. CCS). Two types of storage batteries are included to support variable/intermittent wind and solar generation and to reduce load following by coal and nuclear units under merit order dispatch. Capital and O&M costs by technology are taken from published 2017 EIA data used in NEMS.

The ESIM model monitors how each unit is used over time (i.e., capacity factors). Some units with higher operating costs get pushed down the loading order and eventually retire as wind, solar, and NGCC capacities increase. A shortfall in total capacity is then made up by further expansion of wind, solar, and NGCC. This process accelerates retirements of coal and nuclear units.

We run ESIM in conjuction with a reduced-form gas supply model which we have calibrated to a set of EIA Annual Energy Outlook (AEO2016) sensitivity scenarios. Changes in the supply and demand for gas allows us to simulate resulting gas price impacts.

Both the ESIM and EIA NEMS model include unit dispatch in four seasons for each year. In addition to seasonality, ESIM distinguishes between weekday and weekend electricity load. It is common for older coal units to be put on standby or to power down on weekends. Weekend cycling of coal units is a major contributor to cumulative cycling damage and accelerated unit retirement. After reviewing the literature, Argonne engineers have derived a criterion for the amount of cumulative cycling exposure that an older coal unit could tolerated before it is expected to retire and be replaced.

To get national results for generation, fuel use, and emissions we run seven US regions with the ESIM model. These regions are based on those used in the recent Stanford Energy Modeling Forum study (EMF32). Projections are made over a 50-year horizon to allow for the uptake of advanced low-carbon technologies. We also do a backcasting run stating in year 2010 to compare simulations with history and to set initial conditions for unit cycling that has already accumulated.

Results

Typical results for the discounted present value cost of market-based cycling relative to the discounted present value cost of optimized investments are shown in the Figure below.

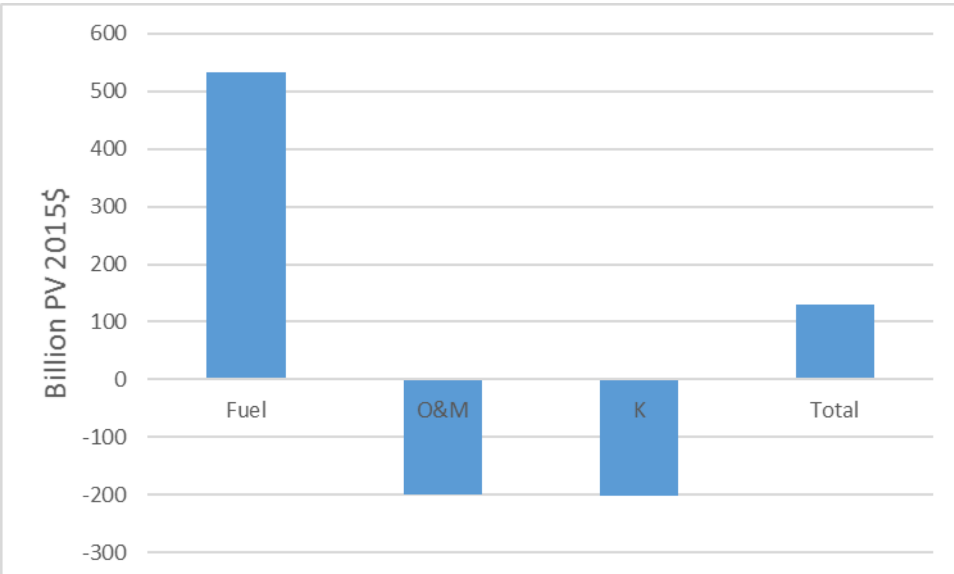

Figure 1: PV Cost Comparison at 5% Real Discount Rate: High Baseload Cycling Case minus Optimized Cost Case

The optimized scenario case involves lower investment rates in Wind, Solar, and NGCC capacity, which reduces retirements of coal and nuclear units. Hence there is less NGCC capacity built allowing earlier adoption of advanced low-carbon baseload technologies. The increased CO_2 emissions from the extended life of existing coal plants is offset by the earlier penetration of advanced low-carbon technologies.

Conclusions

The model simulations that we are doing indicate a need to re-examine the consequences of variable cost dispatch (i.e., short-run marginal cost dispatch) such as over-dependence on natural gas deliverability, risks associated with wind and solar intermittency, the accumulation and lock-in of gas combined cycle capacity, and the possibility of slowing down the adoption of advanced fossil-energy and nuclear baseload technologies. In this work we show that power system present value costs increase over the long-run horizon when power plant dispatch is only based on variable costs.

References

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