Impacts of Wind and Solar on Fossil-Fueled Generators

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D. Lew and G. Brinkman
National Renewable Energy Laboratory

N. Kumar, P. Besuner, D. Agan, and S. Lefton
Intertek APTECH

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Impacts of Wind and Solar on Fossil-Fueled Generators

D. Lew, *Member, IEEE*, G. Brinkman, N. Kumar, P. Besuner, D. Agan, and S. Lefton

***Abstract*—High penetrations of wind and solar power will impact the operations of the remaining generators on the power system. Regional integration studies have shown that wind and solar may cause fossil-fueled generators to cycle on and off and ramp down to part load more frequently and potentially more rapidly. Increased cycling, deeper load following, and rapid ramping may result in wear and tear impacts on fossil-fueled generators that lead to increased capital and maintenance costs, increased equivalent forced outage rates, and degraded performance over time. Heat rates and emissions from fossil-fueled generators may be higher during cycling and ramping than during steady-state operation. Many wind and solar integration studies have not taken these increased cost and emissions impacts into account because data have not been available. This analysis considers the cost and emissions impacts of cycling and ramping of fossil-fueled generation to refine assessments of wind and solar impacts on the power system.**

***Index Terms*—carbon dioxide, coal, cycling, emissions, gas, load following, nitrogen oxide, ramping, solar, sulfur dioxide, wear and tear, wind.**

I. Introduction

REGIONAL integration studies have assessed the impacts of variable generation (VG) such as wind and solar on the power system [1-4]. These studies typically include production simulation modeling of the power system with various levels of VG and examine the impact of variability and uncertainty on the balance of plant. VG displaces the marginal generation on the system, subject to operating and transmission constraints, such as minimum generation levels, ramp rates, and transmission congestion. VG can cause the dispatchable generation to run at lower partial load and cycle on and off more frequently [1].

When fossil-fueled generators cycle on and off or ramp down to minimum generation, the thermal cycling of the components can lead to fatigue, creep and fatigue-creep interaction which results in increased maintenance and repair [5]. This "wear and tear" cost depends on plant design, operation, maintenance, and repair history. Determining the wear and tear cost therefore requires significant investigation and analysis. This type of analysis is typically commissioned by the plant owner to better understand implications of operations of the plant, and these results are proprietary information for the plant owner. As such, this cost has not been included in most integration studies.

Cycling and ramping of fossil-fueled generators also affect emissions and may result in higher emissions rates than steady-state operation. Recent studies have found conflicting results regarding the impact of cycling and ramping on emissions rates [6-7]. Heat rates (CO_2 emissions rates) typically degrade at partial load. NO_X and SO_2 rates are also affected by loading. Startup emissions of CO_2, NO_X, and SO_2 may be significantly higher than steady-state emissions rates. Up-ramps in power output may also result in higher than steady-state emissions.

Phase 1 of the Western Wind and Solar Integration Study (WWSIS) examined the operational impacts of large penetrations of VG in the Western Interconnection of the U.S. [1] At that time, there was little information regarding the detailed wear and tear costs and emissions impacts of cycling and ramping of fossil-fueled units. Phase 2 of the WWSIS focuses on determining wear and tear costs and incremental emissions impacts and using these new data in the security-constrained unit commitment and economic dispatch process. In this paper, we investigate the wear and tear costs and incremental emissions resulting from the cycling and ramping of fossil-fueled generators. These data are for use in production simulation modeling to determine the impacts of wind and solar on the power system. We also consider the impacts of the incremental emissions on Phase 1 WWSIS results to determine a worst-case scenario of emissions impacts.

II. Wear and Tear Costs

The WWSIS found that VG displaced coal and gas generation, depending on the relative prices of coal and gas fuels. On average, for each 3 MW of VG production, 1 MW of dispatchable generation is backed down, and 2 MW are decommitted. Fig. 1 shows the tendency of wind to release reserves from other resources. Increased wind results in the ramping down and cycling off of dispatchable generation.

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D. Lew is with the National Renewable Energy Laboratory, Golden, CO 80401 USA (e-mail: debra.lew@nrel.gov).

G. Brinkman is with the National Renewable Energy Laboratory, Golden, CO 80401 USA (e-mail: greg.brinkman@nrel.gov).

N. Kumar is with Intertek-APTECH, Sunnyvale, CA 94086 USA (e-mail: nikhil.kumar@intertek.com).

P. Besuner is with Intertek-APTECH, Sunnyvale, CA 94086 USA. nadreckl2@yahoo.com).

D. Agan is with Intertek-APTECH, Sunnyvale, CA 94086 USA (e-mail: dwight.agan@intertek.com).

S. Lefton is with Intertek-APTECH, Sunnyvale, CA 94086 USA (e-mail: steve.lefton@intertek.com).

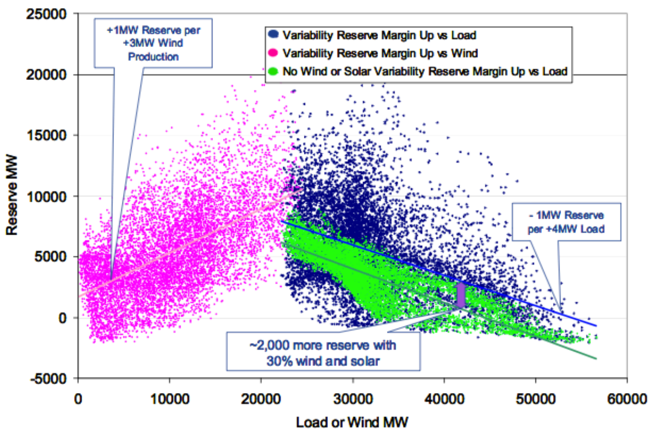

Fig. 1. Impact of wind and load on reserves, showing that, on average, 3 MW of wind production release 1 MW of reserves (pink), and 4 MW of load reduction releases 1 MW of reserves (blue) [1].

A. Methodology

To determine the impacts of cycling and ramping on fossil-fueled plants, in-depth cycling studies have been conducted for specific power plants. Bottom-up, component-level studies use real-time monitoring data, prior engineering assessments of critical components, and a survey of plant personnel. Top-down studies use lightly screened annual maintenance, capital and forced outage costs, unit composite damage accumulation models and statistical regression methods. The top-down analysis can capture major direct effects and even operator error and other indirect effects to estimate cycling costs. The bottom-up accounting techniques can break down costs into component specific costs. The methodology is depicted in Fig. 2.

These studies, which were conducted over several decades for approximately 400 power plants, were used to develop a database of wear and tear costs. These costs are specific to each plant and its operation, and these data are proprietary. It would be prohibitively expensive to conduct these detailed studies for every fossil-fueled power plant in the Western Interconnection. However, by disaggregating the database into types and sizes of plants, generic, non-proprietary data can be extracted to determine wear and tear costs that can be used in a production simulation model.

The cycling cost database was screened to include newer studies with more robust methodologies and results and only plants operating in North America. The sample of plants reflects the variation of cycling costs for each group. However, there are variations—such as past operation, manufacturer, and unit design—that affect cycling costs but are not disclosed here. These plants were divided into the following categories:

- Large coal-fired subcritical steam (300–900 MW)
- Small coal-fired subcritical steam (35–299 MW)
- Large coal-fired supercritical steam (500–1300 MW)
- Gas-fired combined-cycle (combustion turbine/steam turbine and heat recovery steam generator, or CC)
- Gas-fired simple-cycle large-frame combustion turbine (CT)
- Gas-fired, simple-cycle aero-derivative combustion turbine
- Gas-fired steam (50–700 MW).

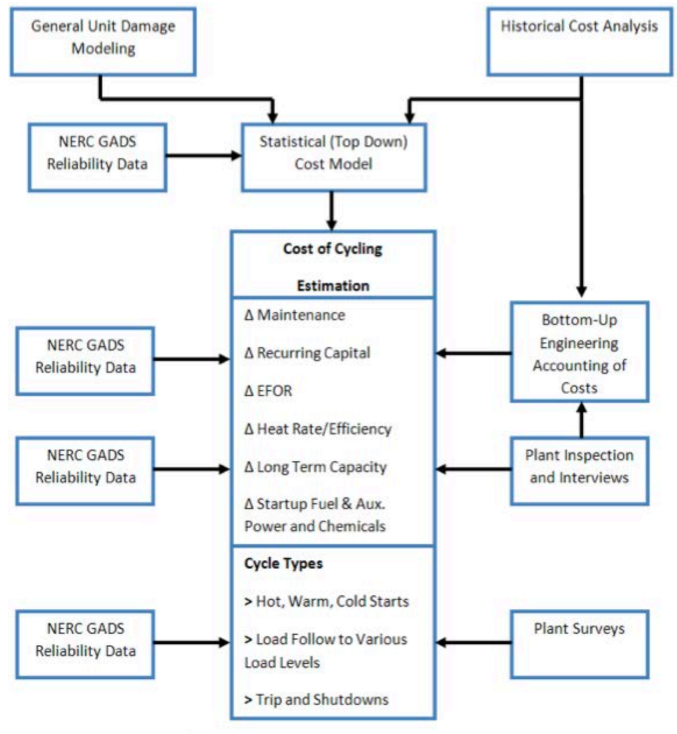

Fig. 2. Cost of cycling methodology. Top-down and bottom-up approaches are used to determine various impacts from on/off cycling and ramping of fossil-fired units.

In this analysis, the following wear and tear impacts were considered:

- Cost of a cold start
- Cost of a warm start
- Cost of a hot start
- Variable operations and maintenance (VOM) cost for baseload operation
- Increased equivalent forced outage rate (EFOR) because of cold start
- Increased EFOR because of warm start
- Increased EFOR because of hot start
- Long-term heat rate degradation
- Cost of ramping from gross dependable capacity (GDC) to less than 80% GDC and back up to GDC (i.e., load following)
- Cost of ramping at a fast ramp rate from GDC to less than 80% GDC and back up to GDC

The definitions of cold, warm, and hot starts vary, depending on the plant category. The cost of wear and tear because of startups includes:

- Maintenance and capital expenditures
- Operational heat rate impacts
- Startup auxiliary power and chemicals
- Startup fuel and manpower.

All costs are in 2011 U.S. dollars.

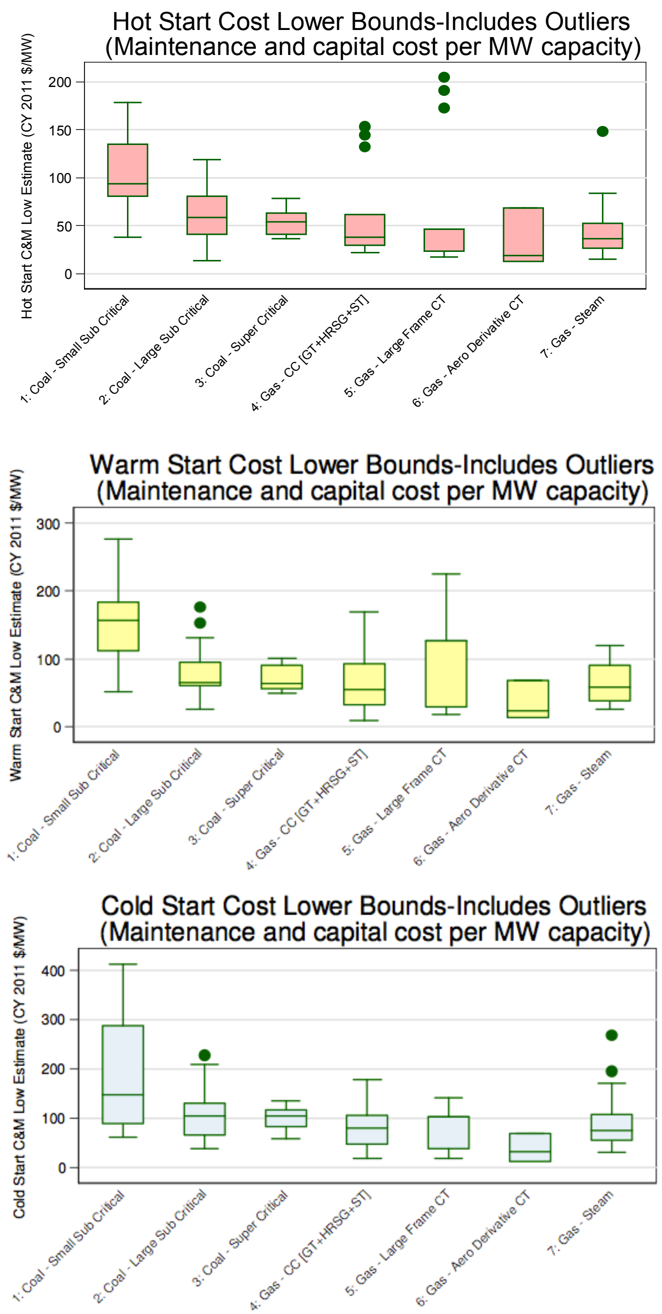

Fig. 3. Hot (top), warm (middle) and cold (bottom) startup lower bound costs. The range shows the 25th to 75th percentile, with the median shown within that range. Certain extrema are depicted by the whiskers in the plots. Outliers (dots) are included in these distributions.

For each plant, a best estimate of cycling costs was determined by a best fit for annual costs and regression constraints. There is some uncertainty in this regression because of the limited sample size, the noise inherent in variations of annual cost and cycling characteristics and the standard and heuristic numerical procedures. Therefore, upper and lower bounds were defined to describe the uncertainty range. These were determined by re-running the regression analysis while forcing the cycling cost estimates to deviate from the best estimate. The range of solutions was assessed visually and by "goodness of fit" statistics. The upper and lower bounds were set where the deviation from the best fit cannot be explained solely by randomness in the sample. A lower bound and an upper bound were determined for each plant. The lower bound data are shown in this paper. The upper bound data are confidential and not shown in this paper but are used in Phase 2 of the WWSIS.

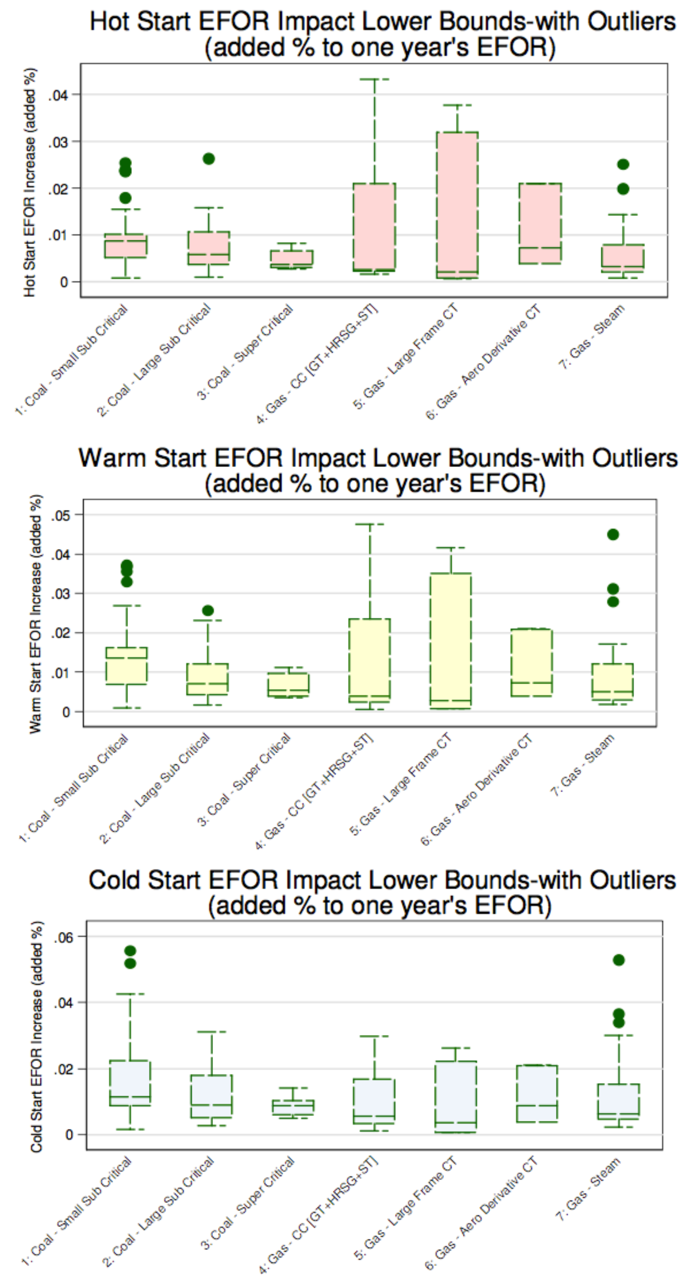

Fig. 4. Hot (top), warm (middle) and cold (bottom) EFOR lower bound impacts. The range shows the 25th to 75th percentile, with the median shown within that range. Certain extrema are depicted by the whiskers in the plots. Outliers (dots) are included in these distributions.

It is important to note that the costs and EFOR impacts in this paper are typical lower bounds. There are large variations between individual units of each type and many factors—including design, vintage, age, past operation, and operations and maintenance history—that would lead to a specific plant deviating from these costs. However, to model a large number of generators, such as across the Western Electricity Coordinating Council, careful application of the range of wear and tear impacts (from lower to upper bounds) in the optimization of unit commitment and economic dispatch can provide meaningful results as to wind and solar impacts.

B. Startup Costs

Fig. 3 reports the typical lower bound costs for hot, warm and cold starts for each category of plant. Generally, the median cold startup cost is about 1.5 to 3 times the hot startup cost. The gas aero-derivative CTs have relatively the same cost for hot, warm, and cold starts. These units were designed to cycle, and every start is essentially cold. Most of the small and especially the large coal-fired units were designed for baseload operation and have higher cycling costs. Some of the highest costs occur in some small coal units that have been cycled and ramped extensively.

C. EFOR Impacts

Fig. 4 shows the increased EFOR for hot, warm, and cold starts for each category of plant. A small subcritical coal plant that is well-represented by lower bounds (e.g., it was designed for flexibility) would have a median lower bound EFOR of 0.0086% per hot start. If that plant began the year with an EFOR of 2% and added 10 hot starts to its usual operation in the year, the EFOR at the end of the year would increase to approximately 2.086%.

There is an inherent tradeoff between higher capital and maintenance expenditures and lower EFOR. This analysis does not delve into the mechanism of this tradeoff but rather reports on actual units with specific capital and maintenance expenditures and specific EFOR. Further research on this issue is needed.

D. Ramping Costs

Fig. 5 shows the cost for a typical ramp, or load-follow. This is defined based on unit type, but typically, any ramp from 100% GDC to less than 80% GDC and back up to 100% would incur this approximate cost.

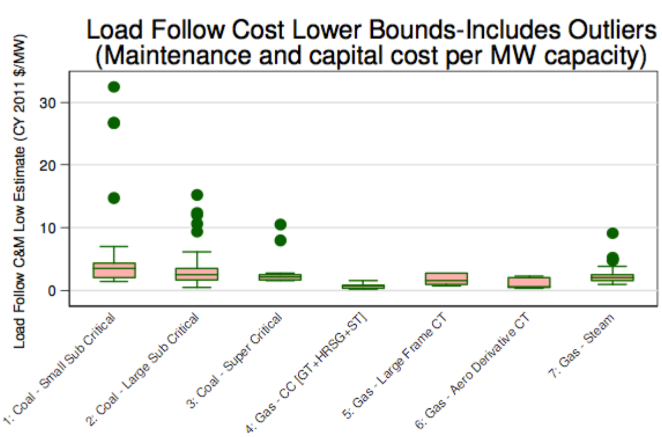

Fig. 5. Lower bound ramping costs. The range shows the 25th to 75th percentile, with the median shown within that range. Certain extrema are depicted by the whiskers in the plots. Outliers (dots) are included in these distributions.

Additional work is examining faster ramp rates. Some units have costs because of faster ramp rates; other units may be incapable of ramping faster than typical ramp rates. Generally, increasing ramp rates by a factor of 1.1 to 2 results in higher ramping costs by a factor of 1 up to 8, depending on plant type.

E. Baseload VOM Costs

The baseload VOM cost was included to ensure there was no double-counting. Instead, the sum of the costs of startups and VOM cost should equal the total VOM cost of that unit. Baseload VOM costs include wear and tear because of baseload operation, chemicals, and other consumables used during operations. Fig. 6 shows the baseload VOM costs.

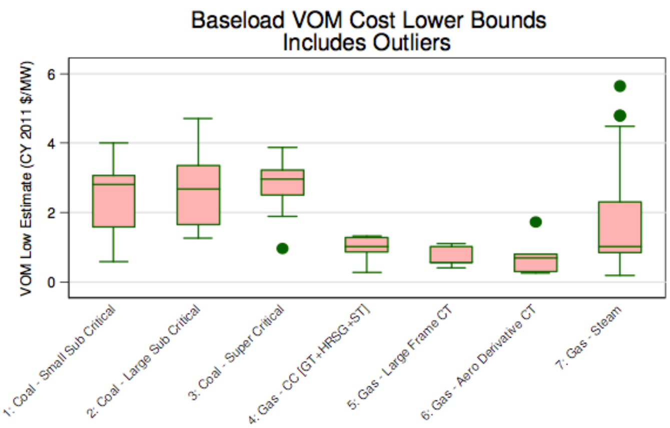

Fig. 6. Lower bound baseload VOM costs. The range shows the 25th to 75th percentile, with the median shown within that range. Certain extrema are depicted by the whiskers in the plots. Outliers (dots) are included in these distributions.

Additional work is underway to determine the wear and tear costs and EFOR impacts for those units that are "best in class". These units, which are taken from the full database, include units in Europe and elsewhere that have low costs for cycling and ramping. They show the potential of units that are designed for flexibility.

III. Emissions

To determine the impacts of cycling and ramping on emissions, measured emissions from nearly every fossil-fueled plant in the US were analyzed. The dataset for this analysis comes from the U.S. Environmental Protection Agency's continuous emissions monitors (CEMs), which are required on all sulfur-emitting units and all units larger than 25 MW in capacity.[1] The monitors report hourly NO_X, SO_2, CO_2, fuel input, and generation. Data from all of 2008 were used because that was the most recent year that the Environmental Protection Agency had released full datasets for bulk download that had been through quality controls. Any missing and substituted data were eliminated from this analysis. In 2008, 94% of generation from combustion electric generating

[1] http://www.epa.gov/airmarkets/emissions/continuous-factsheet.html

units came from units with CEMs.[2] This emissions analysis considers slightly different categories of generation from Section II on Wear and Tear Costs:

- Coal-fired
- Gas-fired combined cycle
- Gas-fired combustion turbine (CT)
- Gas-fired steam.

This paper reports on the emissions analysis for NO_X, SO_2, and CO_2 for part-load operation and startups. Emissions because of ramping were also investigated but found to be much less significant so are not reported here.

A. Methodology

1) Heat Rates:

Emissions and heat rate curves were fit for every unit using hourly data points for heat input, NO_X and SO_2. Heat input was fit with generation as the independent variable, while NO_X and SO_2 emissions were fit with heat input as the independent variable. A nonparametric local linear fit with tri-cube weighting was used so that no predefined functional form was set to the units. Hours immediately following startups were not considered in the fit.

Fig. 7 shows an example of fitted heat rate curve versus generation for a typical unit. While some severe hourly data outliers are apparent, they are usually not numerous enough to destroy the overall fit. Most units have good fits for all types of emissions. The units with correlation coefficients below 0.7 between the actual emissions and predicted emissions (based on the local linear fit to generation) were not included in the analysis.

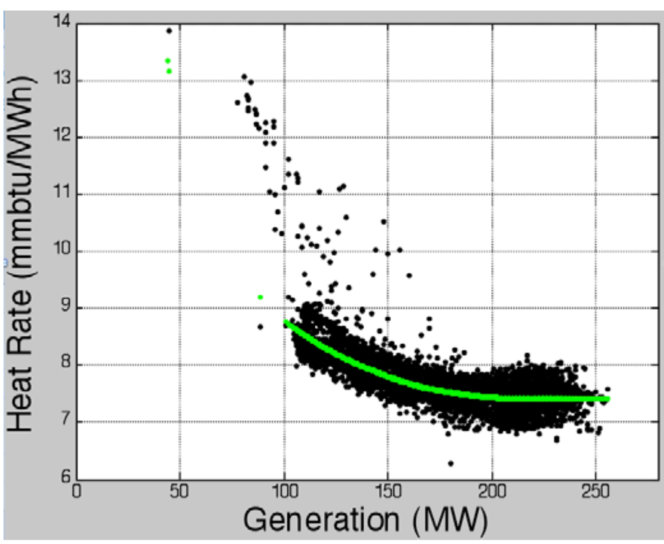

Fig. 7. Typical heat rate curve for gas CC unit from measured CEMs dataset. The green line shows local linear fit. Residuals are defined as the difference between the measured emissions and the fit.

Nearly all units had good heat rate fits. Some coal and gas CTs had poor NO_X fits, and about two-thirds of the sulfur-controlled coal units had poor SO_2 fits. The latter may be because that sulfur controls may be run for only part of the year.

2) Startups:

When fossil-fueled units startup, they often emit pollutants at a higher rate until they reach the minimum generation level for efficiency and pollution-control equipment to work properly. In this analysis, the difference between the actual emissions for each pollutant and the predicted emissions (based on the local linear fit described above) was summed for each hour between startup and the hour that unit reached its minimum generation level. Minimum generation levels were defined as the level at which that specific unit was operating at or above 95% of hours that the unit was online (not including the hour of startup or the hour immediately following startup). Emissions were also counted as startup emissions if the unit was emitting pollutants prior to startup. This is common at coal units as the boiler comes up to temperature. All startup emissions for each unit were summed and divided by the number of starts to estimate the average emissions per startup.

Fig. 8 shows an example of startup emissions. This unit was started at hour 1764 and reached its minimum generation level at hour 1767, after which actual and predicted NO_X match quite well. The emissions between the actual and predicted curves prior to hour 1767 are counted as startup emissions.

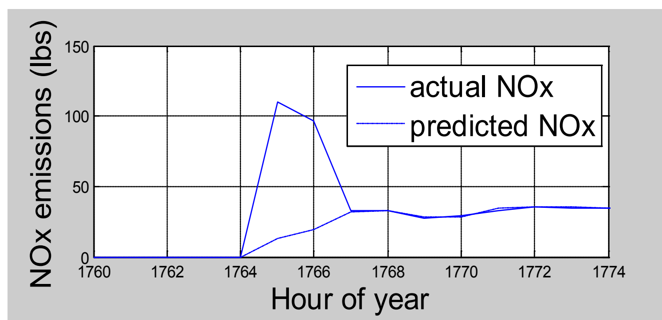

Fig. 8. Example of startup NO_X emissions. Actual NO_X measurements are shown by the solid blue line, and predicted NO_X from the local linear fit is shown by the dashed blue line. Startup NO_X emissions are defined as the difference between the actual NO_X and predicted NO_X.

B. Emissions Results

All results presented are generation-weighted averages, so units that produce large amounts of electricity have more influence than units that do not produce much electricity.

1) Part-Load Emissions:

Fig. 9 shows the average heat rate curves. These can be converted to CO_2 per megawatt-hour based on the carbon content of the fuel used. CC units are the most efficient at full-load and part-load, but CCs and CTs have the most significant penalties for operating at 50% compared to 100% of maximum generation. Coal, CTs, and gas steam units have similar heat rates when operating at full load, but at 50% the coal and gas steam units have heat rates only 6% higher than full load. CTs are much less efficient at part-load.

[2] Total generation from combustion sources based on EIA-923 form data. Combustion sources were assumed to be all sources that did not use nuclear, geothermal, water, sun, or wind for the fuel code.

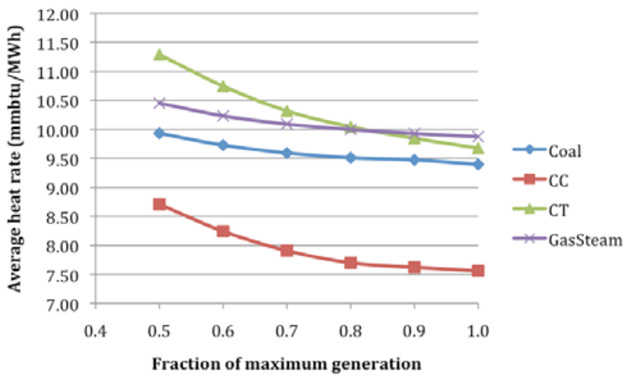

Fig. 9. Average heat rate curves for coal, gas CCs, gas CTs, and gas steam units in the U.S.

Fig. 10 shows the average NO_X emissions as a function of load for the different unit types. There is approximately an order of magnitude difference between steam units (coal and gas) and gas CCs and CTs. However, part-load operation leads to a penalty for the CCs and CTs but is a benefit for the steam units. For example, coal units operating at 50% emit 3% less NO_X per megawatt-hour compared with full-load operation. Gas CCs emit 29% more NO_X per megawatt-hour at 50% load compared with full-load. Most of the NO_X from all units is created from nitrogen in the combustion air ("thermal" NO_X) as opposed to in the fuel, so flame temperature is a strong driver of NO_X emissions. The type of NO_X control technology had modest impacts on the part-load performance. Dry low- NO_X burner systems tend to have part-load (at and above 50% load) performance that is better than that of other technologies.

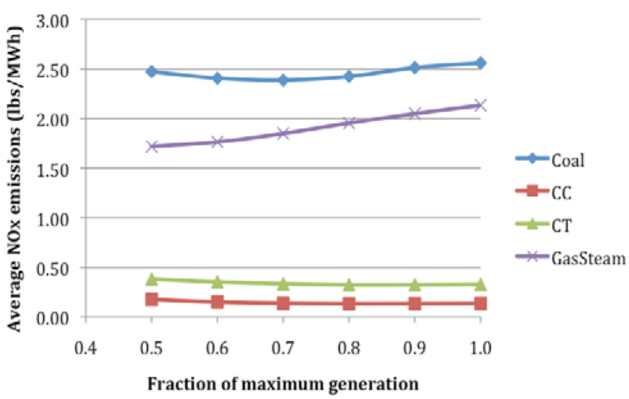

Fig. 10. Average NO_X curves for each generation type.

SO_2 emissions come primarily from coal plants, as natural gas has very little sulfur in it. Fig. 11 shows the SO_2 curves for coal units with and without SO_2 controls. These results should be viewed with some caution, because more than half of the controlled units were eliminated from the analysis because of poor fits. The poor fits were primarily because the units were regularly operated without the SO_2 controls, making curve-fitting difficult. The shape of the SO_2 curve for units without controls is almost identical to the heat rate curve because the amount of SO_2 released is entirely a function of how much fuel is burned (and, therefore, how much sulfur is in that fuel). For controlled units, part-load operation leads to a 20% reduction in emissions per megawatt-hour.

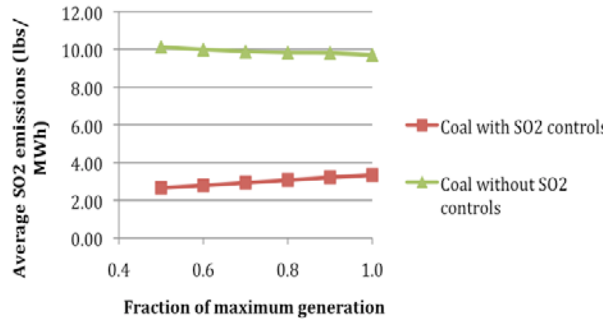

Fig. 11. Average SO_2 curves for coal units with and without SO_2 controls.

2) Startup Emissions:

Starting an offline unit also leads to extra fuel use and emissions. Most coal units are started using oil or gas, so the heat input penalty and the CO_2 emissions penalty might not be identical, depending on the carbon content of the startup fuel.

Table I shows the startup penalties for different types of units and different emissions. They are expressed in million British thermal units or pounds per megawatt of unit capacity. For example, a coal unit emits 2.51 lbs/MW capacity of excess NO_X during startup. This is equivalent to operating the unit at full-load for 0.98 hours. Although coal units emit the most NO_X during startups, CCs and CTs emit more as a fraction of full-load emissions. Starts were not segregated among cold, warm, and hot starts, as many units did not have enough data to justify the split.

TABLE I
STARTUP EMISSIONS PER MEGAWATT CAPACITY.

	Heat Input (MMBTU/MW)	NO_X (lbs/MW)	SO_2 (lbs/MW)
Coal (all)	11.4	2.51	3.90
Gas CC	2.4	0.83	n/a
Gas CT	3.8	0.59	n/a
Gas Steam	9.3	-0.03	n/a

IV. APPLICATION TO THE WESTERN WIND AND SOLAR INTEGRATION STUDY

Wind and solar generation may increase the cycling and ramping of fossil-fueled generation, resulting in higher emissions than if these fossil-fueled units were run at steady state. To understand these impacts in more detail, the NO_X emissions from Phase 1 of the WWSIS [1] were re-analyzed.

Two cases were considered:

1) Each unit had an average emissions rate for each hour of the year.

2) Emissions were a function of plant output level and additional emissions because of startups were included.

In both cases, the no-wind and high renewables scenarios (30% wind energy and 5% solar energy in the study footprint) were analyzed to look at the emissions reduction because of wind and solar.

In Case 1, no startup or part-load emissions were considered. Each unit had a constant emissions rate equal to the average full-load emissions rate for each unit type (coal, CC, CT, and gas steam). The re-analysis did not consider unit-specific emissions rates; it simply assumed each unit was an average unit of its type.

In Case 2, startup and part-load emissions assumed that emissions rates were variable (as specified by Fig. 10) and startup penalties (Table I) were also included.

In the case that considered cycling impacts, startups caused a 2.0% reduction in the expected emission benefit of wind. Part-load NO_X inefficiencies led to a 0.3% reduction in the expected emission benefit. In the case that did not consider cycling impacts, wind production displaced 0.439 lbs of NO_X per megawatt-hour. Once cycling was considered, the model projected that wind would displace 0.429 lbs/MWh (2.3% less than when cycling and part-load were not considered). This is not a specific projection for the Western Electricity Coordinating Council. It is an example of how cycling might impact the emissions benefits of wind in a generic system with hourly generation based on the WWSIS results.

V. Conclusions

Increased cycling on and off and ramping down to partial load of fossil-fueled generators have impacts on the costs and performance of those units. In this paper, aggregated results of top-down and bottom-up analyses for hundreds of plants have been synthesized and reported in a generic fashion to protect confidentiality while providing usable data for production simulation modeling. Startup costs, EFOR impacts, baseload VOM costs, and ramping costs are reported. The largest impacts are from on/off cycling, especially cold starts and small subcritical coal units. Generally speaking, ramping costs are relatively small, especially when units are ramped at normal ramp rates.

There are many different methodologies for estimating emissions benefits of VG and they can be complex to implement in the real world. An accurate methodology will calculate the emission rate of generators used to supply marginal production and also consider impacts of variable and uncertain generation on unit commitment decisions and impacts of operating the generators differently (e.g., cycling and ramping). The analysis described in this paper will help characterize the emissions impacts of cycling and ramping, which will be necessary to model the complete emissions impacts of VG. The results of this work show that the impacts of generator cycling and part-loading can be significant (e.g., for CC generators); however, these impacts are modest compared with the overall benefits of replacing fossil-fueled generation with variable renewable generation.

A re-analysis of the WWSIS generation profiles shows that startups and part-load emissions impacts reduce the NO_X benefits of wind by less than 3%. This number could vary depending on the generating fleet and the variable generators that are being considered.

Future work will model the Western Interconnection with varying levels and types of renewable penetrations. A production cost model will be used to optimize unit commitment and economic dispatch with these new wear and tear and emissions impacts included. This will likely reduce the cycling and ramping of the fossil-fueled units from that in previous work where these costs and impacts were not considered to this degree. This should result in a deeper level of understanding of the real impacts of wind and solar power on the power system, other generators, and emissions.

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VII. Biographies

Debra Lew (M'08) graduated with an MS and PhD in Applied Physics from Stanford University, CA, and with BS degrees in Physics and Electrical Engineering from the Massachusetts Institute of Technology, MA. Debra presently works as a Senior Engineer in the Transmission and Grid Integration Group at the National Renewable Energy Laboratory, where she focuses on integration of variable generation into the power system.

Greg Brinkman is an energy analysis Engineer in the Strategic Energy Analysis Center at the National Renewable Energy Laboratory, where he is a lead production simulation modeler He graduated with a PhD in mechanical engineering from the University of Colorado at Boulder, an MPP in environmental policy from the University of Maryland and a BS in electrical engineering from Purdue University.

Nikhil Kumar graduated with a MS in Industrial and Systems Engineering from North Carolina State University and is currently pursuing his Graduate Certificate in Management Science and Engineering at Stanford University, CA. Nikhil currently works as a lead analyst - Utility Economics and Smart Grid in Intertek APTECH's Power Group.

Philip Besuner consults to Intertek APTECH on a variety of component and system reliability and other statistical and engineering issues. He has an MS degree in engineering mechanics and more than 45 years of experience focused mainly on mechanical and electrical failure modes, fracture mechanics, and related reliability topics.

Dwight Agan is a senior project manager for Intertek APTECH. He is a mechanical engineer (BS and MS in Mechanical Engineering from Stanford University) with 25 years' experience executing and leading energy, environmental and business projects. He is the project manager for Intertek's major endeavors for PJM and the National Renewable Energy

Laboratory/Western Electricity Coordinating Council to integrate new renewable portfolios.

Steve Lefton is the director of Power Plant Projects at Intertek APTECH and is the original developer of the Cost of Cycling Analysis and COSTCOM which is a real time cost calculation code for power plants. He has been the principal investigator of all APTECH's and Intertek's analysis of some 400+ cost of cycling studies in USA/Europe/Australia and has successfully testified to many Public Utilities Commissions and in court as to their validity.