A Systematic Approach to Better Understanding Integration Costs

Preprint

Gregory B. Stark
National Renewable Energy Laboratory

Presented at the Energy Policy Research Conference
Denver, Colorado
September 10–11, 2015

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Conference Paper
NREL/CP-5D00-64930
September 2015

Contract No. DE-AC36-08GO28308

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Available electronically at SciTech Connect http:/www.osti.gov/scitech

Available for a processing fee to U.S. Department of Energy and its contractors, in paper, from:

U.S. Department of Energy
Office of Scientific and Technical Information
P.O. Box 62
Oak Ridge, TN 37831-0062
OSTI http://www.osti.gov
Phone: 865.576.8401
Fax: 865.576.5728
Email: reports@osti.gov

Available for sale to the public, in paper, from:

U.S. Department of Commerce
National Technical Information Service
5301 Shawnee Road
Alexandria, VA 22312
NTIS http://www.ntis.gov
Phone: 800.553.6847 or 703.605.6000
Fax: 703.605.6900
Email: orders@ntis.gov

Cover Photos by Dennis Schroeder: (left to right) NREL 26173, NREL 18302, NREL 19758, NREL 29642, NREL 19795.

NREL prints on paper that contains recycled content.

A Systematic Approach to Better Understanding Integration Costs

Gregory B. Stark, P.E., National Renewable Energy Laboratory

When someone mentions integration costs, thoughts of the costs of integrating renewable generation into an existing system come to mind. We think about how variability and uncertainty can increase power system cycling costs as increasing amounts of wind or solar generation are incorporated into the generation mix. However, seldom do we think about what happens to system costs when new baseload generation is added to an existing system or when generation self-schedules. What happens when a highly flexible combined-cycle plant is added? Do system costs go up, or do they go down? Are other, non-cycling, maintenance costs impacted? In this paper we investigate six technologies and operating practices—including VG, baseload generation, generation mix, gas prices, self-scheduling, and fast-start generation—and how changes in these areas can impact a system's operating costs.[1]

Introduction

The paper begins by providing a working definition of integration costs and four components of variable costs. Next, it describes the study approach and how a production cost modeling-based method was used to determine the cost effects, and, as a part of the study approach section, it describes the test system and data used for the comparisons. Then, it presents the research findings, and, in closing, suggests three areas for future work.

Integration Costs Definition

For this project, integration costs were defined as the change in production costs associated with a system's ability to accommodate the variability and uncertainty of the net load. The two sources of variability and uncertainty considered were load and variable generation (VG), and four components of production costs were investigated: cycling costs, non-cycling variable operations and maintenance costs (VO&M), fuel costs, and reserves provisioning costs. Capital costs and other fixed costs were not included in the study.

Study Approach

The study used a production cost modeling approach similar to that used in Phase 2 of the Western Wind and Solar Integration Study (Lew et al. 2013), in which security-constrained unit commitment and dispatch models were developed, and differences in production costs were used to estimate cost impacts.

The test system used was a modified version of the Illinois Institute of Technology's (IIT's) Institute of Electrical and Electronics Engineers 118-bus model (IIT 2013) overlaid with

[1] This article provides a synopsis of recent integration costs research commissioned by the U.S. Department of Energy and performed by the National Renewable Energy Laboratory in collaboration with an industry-based technical review committee (Stark 2015).

projected operating loads from the Western Electricity Coordinating Council (WECC 2011) for Sacramento Municipal Utility District, Public Service Colorado, and Puget Sound Energy. The system differed from the IIT system in two ways: (1) generator and transmission capacities were doubled, and (2) combined-cycle (CC) units replaced some coal units. These modifications and geographic regions were selected in consultation with the technical review committee (TRC) so that the test system would provide a reasonable approximation of an actual interconnection yet be small enough to allow the research team to investigate a large number of scenarios.

The study year for the work was future year 2020 with WECC-provided load and NREL-provided wind and solar power estimates (actual year 2006 data were statistically scaled). Generator sizes ranged from 40-MW oil-fired combustion turbines (CTs) to 840-MW coal-fired steam plants, and the average generator size was 237 MW. The peak load, which occurred in late July, was 11,765 MW, and the average load was 7,324 MW.

The reference simulation, to which the other simulations were compared, had a nominal generation mix of 40% coal, 47% gas, 11% hydropower, and 2% VG on an annual energy-provided basis.

New Generation Impacts

The goal of the new generation research was to better understand how adding generation to an existing system affected costs. Two types of new generation were investigated: the addition of increasing levels of VG (wind and photovoltaic solar in an approximate 3:1 ratio) and the addition of either a flexible or an inflexible 840-MW coal plant.[2] The simulations differed only in the type and amount of new generation.

In the study, two kinds of maintenance-related costs were investigated: cycling costs and VO&M costs. Both types of new generation increased cycling costs; however, VG decreased VO&M costs, whereas new baseload increased system-wide VO&M costs. Specifics of the cost effects are provided below.

As expected, adding VG increased system-wide cycling costs significantly (see Figure 1),[3] increasing these costs by $1.12/MWh of VG added in the 10% VG simulation and by $1.47/MWh for the 40% VG simulation.[4] Likewise, new baseload also increased cycling costs, with costs increasing by $0.57/MWh of new, flexible baseload and by $0.31/MWh of new, inflexible baseload.[5]

[2] The flexible coal plant operated between 50% and 100% of its rated capacity, whereas the inflexible coal plant was limited to operating between 90% and 100% of its rated capacity.
[3] Non-fuel costs are the sum of the cycling and VO&M costs. Total costs are the sum of the non-fuel and fuel costs.
[4] For simulations that included new generation, costs were normalized per unit of new energy provided by new generation, which helped facilitate direct comparisons among the new generation scenarios.
[5] Although somewhat counterintuitive, the cycling costs in the flexible coal scenario were higher than in the inflexible coal scenario. The dispatch optimization was able to use the flexibility of the flexible baseload unit to displace other, more expensive costs. Although cycling costs increased, the overall generation costs decreased.

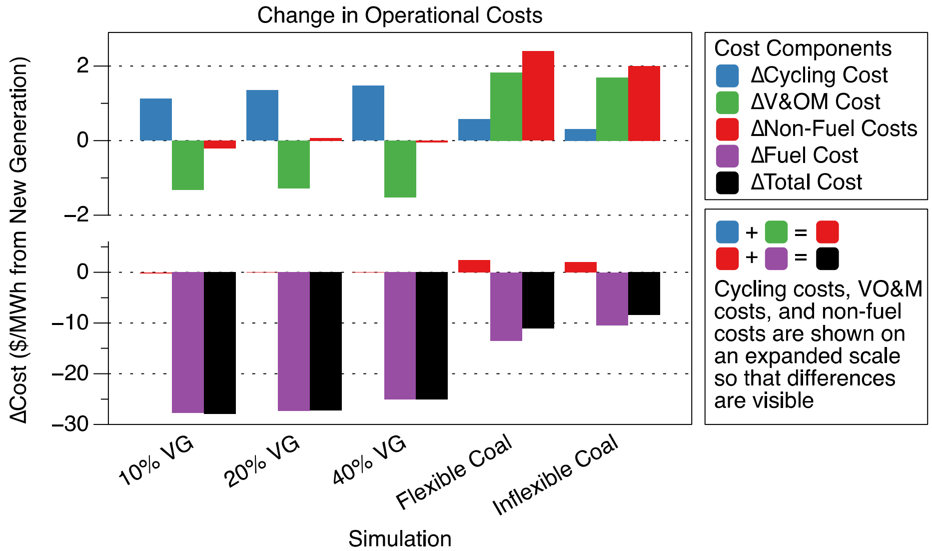

Figure 1. Breakout of incremental operating costs for new generation simulations

Although both types of new generation increased cycling costs, the VG also displaced system-wide VO&M costs, effectively offsetting the increased cycling costs. In contrast, the addition of new baseload actually increased overall VO&M costs by displacing the gas-fired generation that is less expensive to maintain.[6] The net effect was that the system-wide non-fuel incremental costs of adding VG were small (ranging from a $0.21/MWh cost savings to a $0.07/MWh cost increase), whereas adding new baseload generation increased the overall non-fuel system costs moderately ($2.40/MWh for the flexible coal scenario and $2.00/MWh in the inflexible coal simulation).

Table 1 provides a breakout of how adding new generation affected the cycling costs of the individual generator types. Interestingly, the largest impact to the cycling costs of the coal-fired generation occurred when a new baseload plant was added. The average cycling costs more than doubled,[7] and the effects of adding VG did not reach similar levels until the VG penetration reached 40%.

Table 1. Increases (Decreases) in Cycling Costs per MWh of New Generation Added ($/MWh)

Type	10% VG	20% VG	40% VG	Flexible Coal	Inflexible Coal
Coal	0.14	0.12	0.26	0.30	0.30
CC	0.49	0.52	0.30	0.15	(0.10)
CT Gas	0.43	0.57	0.75	0.08	0.09
Total	1.12	1.35	1.47	0.57	0.31

[6] Both the cycling costs and VO&M costs used in the study were derived from APTECH's *Power Plant Cycling Costs* report (Kumar et al. 2012). This report was jointly commissioned by WECC and NREL.
[7] The reference cycling costs for coal, CC, and CT generation are $0.26/MWh, $0.47/MWh, and $6.34/MWh (Stark 2015).

Also of interest is how the CC costs varied with VG penetration. Although CC cycling costs increased for all three levels of VG penetration, the largest cost impacts were at the low and medium penetrations. At the highest VG penetration, CC costs were less affected, because coal was called upon to provide increased amounts of load following,[8] and cycling cost increases were shifted to coal-fired and CT gas generation.

Overall System Impacts

This section reports how changes in the generation mix and system parameters (e.g., generator start times and natural gas prices) affected production costs. The results are grouped into two sections: (1) generation mix effects, in which three identically sized systems with various generation mixes were compared; and (2) operational parameter effects, in which systems that are otherwise identical except for an operation parameter change (e.g., fuel price) or dispatch scheme (e.g., self-scheduling) were studied.

Generation Mix Effects

The goal of the generation mix research was to better understand how differences in generation mix affect costs. Three generation mixes were investigated: (1) a low-coal/high-gas mix (15% coal by annual energy delivered), (2) the reference scenario (40% coal), and (3) a high-coal/low-gas mix (65% coal). The effect of generation mix on production costs is shown in Figure 2. Both cycling costs and VO&M costs increased with coal penetration, with the combined costs (i.e., the non-fuel costs) increasing from $1.54/MWh in the low-coal system to $2.04/MWh in the reference-coal system and $2.59/MWh in the high-coal system, an increase of $1.05/MWh (68%).

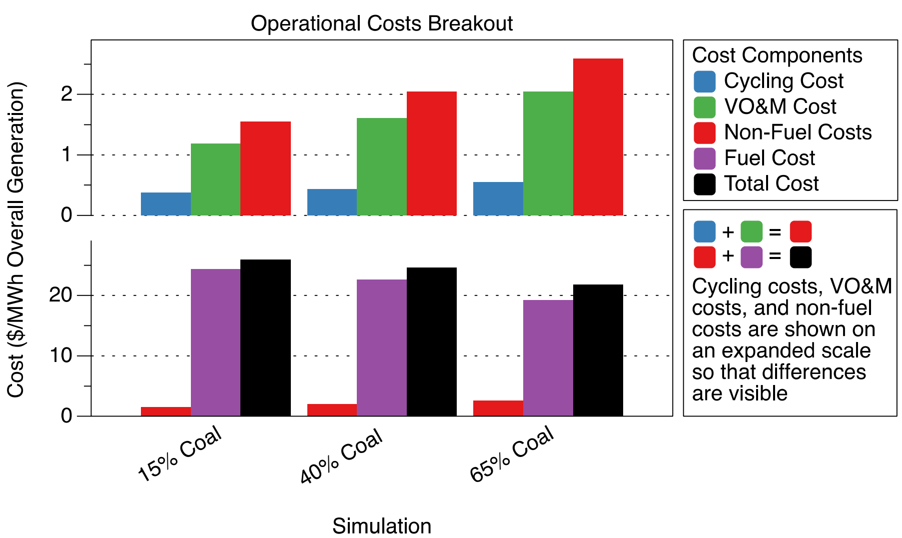

Figure 2. Operational costs for generation mix simulations

As coal penetration increased, both fuel costs and overall operating costs were reduced, with overall costs decreasing from $25.95/MWh in the low-coal system to $24.64 at reference

[8] At the lower variable generation penetrations, VG primarily displaced CC generation; however, as the amount of VG increased, it increasingly displaced baseload coal (Stark 2015).

penetrations and \$21.83/MWh at high penetrations, a reduction of \$4.12/MWh (16%). The combined effect was that cycling and V&OM cost increases reduced overall operational cost savings by almost 20% when compared to costs in the low-coal system.

Table 2. Generation Mix Simulations: Average Cycling Costs by Generator Type ($/MWh Delivered)

Type	15% Coal	40% Coal (Reference)	65% Coal
Coal	0.22	0.26	0.29
CC	0.30	0.47	1.08
CT Gas	4.51	6.34	7.67
Wt. Avg.	0.37	0.43	0.55

In absolute cost terms, generation mix most affected the CT cycling costs, and these costs increased by \$3.15/MWh (70%) as the coal penetration increased from 15% to 65%. CC costs also increased markedly with increasing coal penetration, with costs more than tripling (a \$0.78/MWh impact) compared to costs in the 15% coal scenario.

Operational Parameter and Self-Scheduling Effects

This research investigated how natural gas prices,[9] generator flexibility,[10] and self-scheduling[11] affected costs. All systems studied in this section were identical except for changes in operational parameters or dispatch schemes, and the effects of these factors on production costs are shown in Figure 3.

[9] A reference gas price of \$4.50/MMBtu was used in all simulations except for the high and low gas price sensitivities. Gas prices of \$2.50/MMBtu and \$6.50/MMBtu were used in the low and high gas price simulations.
[10] Coal and combined-cycle start times were 4 hours and 1 hour in the fast-start generation simulation compared to 24 hours and 4 hours in the other scenarios.
[11] Two levels of self-scheduling were investigated: one in which 50% of the coal by capacity self-committed and another in which 50% of the coal was dispatched at full capacity.

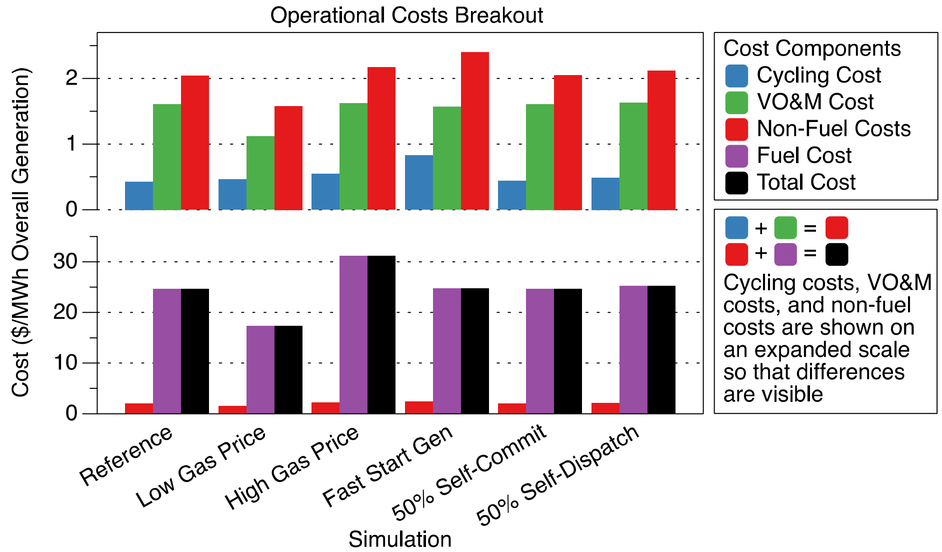

Figure 3. Operational costs for various operating schemes

The largest impact on non-fuel costs was in the fast-start generation simulation, in which increased cycling costs were traded for reduced fuel use. In the fast-start generation case, stopping and starting a fast-start machine was less expensive than leaving it running at minimum generation levels during low-load time periods. The high gas price simulation showed a similar trend—i.e., it was less expensive to shut down and restart gas-fired generation than to reduce its output.

Although it did not have the largest impact, the cost effects related to self-dispatching were perhaps the most interesting. In a simulation that contained effectively no VG (<2%) and differed from the reference simulation only in how the coal plants were dispatched (50% of the coal fleet was dispatched at rated capacity[12]), cycling costs increased 12% ($0.06/MWh) and overall generation costs increased 3% ($0.67/MWh). Self-dispatched generation also caused shifts in the types of generators that provided load following (see Table 3), increasing CC cycling costs by $0.14/MWh (30%).

Table 3. Operating Scheme Effects: Average Cycling Costs by Generator Type

Type	Reference	Low Gas Price	High Gas Price	Fast Start Generation	50% Self-Commit	50% Self-Dispatch
Coal	0.26	0.56	0.25	0.22	0.25	0.25
CC	0.47	0.28	0.69	1.03	0.49	0.61
CT Gas	6.34	5.68	7.60	99.98	6.62	2.54
Wt. Avg.	0.43	0.46	0.55	0.83	0.44	0.49

Finally, the operation scheme that had the largest impact on cycling cost was the deployment of fast-start generation (see Table 3). The improved ramp rates and shortened start times of the CC machines allowed this class of generation to displace most of the CT fleet—leaving the turbines

[12] Discussions with the project's TRC revealed that self-dispatching rates for baseload plants are believed to be as high as 80% in some regions of the United States. The 50% value selected by the TRC was considered conservative.

to run for very short periods of time. Although the cycling costs of the CC and CT[13] fleet did increase in the fast-start generation scenario, the cost increases were borne by the same class of generation that was added to the system, and the increased cycling costs were traded for lower, overall generation costs.[14]

VG and Gas Forecast Errors

The last set of experiments investigated how day-ahead gas orders differed from actual gas use as the amount of VG increased.[15] Gas order errors have the potential to create both gas delivery and contracting issues,[16] and the goal of this research was to better understand how increases in variable generation penetration affects gas order errors. Errors were found to increase with VG penetration and are shown in Table 4.

Table 4. Errors in Natural Gas Orders

Error Magnitude	2% VG	10% VG	20% VG	40% VG
<10% Error	100.0%	86.6%	73.4%	52.6%
10%–20% Error	0.0%	11.2%	18.9%	28.8%
20%–30% Error	0.0%	1.6%	5.8%	12.1%
> 30% Error	0.0%	0.5%	1.9%	6.6%

The order errors increased markedly as VG penetration increased—to the point at which 48% of the gas orders were off by more than 10% at the highest VG penetration level. Given the magnitude of the errors, further study is suggested.

Conclusions

Although integration cost results will always be somewhat system specific, the research team believes that the study approach and model runs provide a useful body of work for ongoing analysis. The overall findings are summarized below, followed by suggestions for future work.

With respect to the cost impacts of adding new generation to an existing system, both new VG and baseload were found to increase cycling costs. However, cycling cost increases were offset by reductions in VO&M costs in the VG scenarios, with the overall non-fuel cost impacts ranging from a decrease of $0.21/MWh to an increase of $0.07/MWh. In contrast, new baseload non-fuel operating costs increased between $2.00/MWh and $2.40/MWh, further driving up system-wide non-fuel operating costs and shifting cycling costs to other generators.

[13] Although the cycling costs of the CTs increased tremendously in the fast-start generation scenario, the CTs were used so infrequently that the cost increase had a negligible impact on overall system costs.
[14] Adding fast-start capability to the CC fleet did increase cycling costs; however, the generators primarily impacted by the change were the new fast-start CC plants. This differed from the self-dispatch scenario, in which reducing the flexibility of self-dispatched coal plants reduced the cycling costs of the self-dispatched plants but caused the cycling costs of other classes of generation to increase (i.e., the self-dispatched plants shifted part of their operating costs to other generators).
[15] Perfect load forecasts were used because load forecasts were not available. Consequently, all forecast errors were attributed to wind and solar, likely putting more of a burden on wind and solar forecasts than is realistic.
[16] Gas shortages can create obvious issues, with the potential for generators to be starved for fuel. However, gas excesses can also create problems, such as having to pay for gas that was not needed.

In terms of cost impacts related to generation mix, both cycling and system-wide VO&M costs were found to increase with coal penetration. As the amount of energy from coal increased from 15% to 65%, cycling costs increased from \$0.37/MWh to \$0.55/MWh, an increase of \$.18/MWh (49%).

Differences in operating parameters and dispatch schemes were also found to affect cycling costs. At high natural gas prices, cycling became cheaper than using fuel at minimum generation settings, and plants were shut down and restarted during times of low load, thereby saving fuel costs but increasing cycling costs (cycling costs were \$0.46/MWh at a \$2.50/MMBtu gas price but increased to \$0.55/MMBtu at a \$6.50/MMBtu gas price). In the dispatch group of experiments, one of the more interesting results was the effect of self-scheduling. Even at a rather modest self-dispatching rate of 50%, CC cycling costs increased 30% (\$0.14/MWh) and overall generation costs increased 3% (\$0.67/MWh), with the cost increases incurred by generators that did not self-schedule.

Finally, in the gas order error investigation, gas order errors were found to increase with increasing VG penetration. At the highest penetration level in the study (40% VG), day-ahead gas use estimates were found to be in error by more than 10% almost 50% of the time.

Future Work

Based on the above findings, we suggest three areas for future work: (1) an assessment of how differing types of integration costs affect both the system and its various generator classes, (2) further investigation into how dispatch schemes impact operational costs at high VG penetration levels, and (3) the development of a better understanding of the effect of gas order errors on system operations.

Increases in cycling costs can happen for very different reasons. In some cases, such as fast-start generation, increased cycling costs were traded for fuel-use reductions, with the overall system costs decreasing because the fuel cost savings were greater than the cycling cost increases. The new, fast-start generation carried most of the cost (and maintenance) increases. In other situations, such as self-scheduling, reducing the coal fleet's flexibility increased overall costs and increased the cycling costs of other generator classes. Further investigation is suggested to better understand the nature of cycling costs impacts.

Self-dispatching negatively impacted integration costs even at moderate self-dispatching levels (50%) and in the effective absence (<2%) of VG. Additional work is suggested to develop a better understanding of the interrelationship between dispatch schemes and VG penetration.

Finally, the finding that gas order errors increased markedly with increasing VG penetration, especially given the recent reports (July 10, 2015) of gas shortages in California,[17] suggests that a better understanding of the relationship between VG penetration and natural gas use is needed.

[17] In July 2015, as the western United States baked under triple-digit heat, the California Independent System Operator issued the first Flex Alert in two years, citing natural gas capacity issues in southern California. See http://www.argusmedia.com/News/Article?id=1069150&sector=POWER&region=ALLREGION for more information.

References

IIT. 2013. "Index of Data Illinois Institute of Technology." Accessed January 2013: motor.ece.iit.edu/data/.

Kumar, N., P. Besuner, S. Lefton, D. Agan, and D. Hilleman. 2012. *Power Plant Cycling Costs.* (Technical Report). NREL/SR-5500-55433. Work performed by Intertek-APTECH, Sunnyvale, California. Golden, CO: NREL. Accessed January 2013: www.nrel.gov/docs/fy12osti/55433.pdf.

Lew, D., G. Brinkman, E. Ibanez, A. Florita, M. Heaney, B. Hodge, M. Hummon, and G. Stark. 2013. *The Western Wind and Solar Integration Study Phase 2*. (Technical Report). NREL/TP-5500-55588. Golden, CO: NREL.

Stark, G. 2015. *A Systematic Approach to Better Understanding Integration Costs.* NREL/TP-5D00-64502. (Technical Report). Golden, CO: NREL.

WECC. 2011. *Assumptions Matrix for the 2020 TEPPC Dataset.* Accessed January 2013: www.wecc.biz/library/StudyReport/Documents/Assumptions%20Matrix%20for%20the%202020%20TEPPC%20Dataset.pdf.