Update of Reliability and Cost Impacts of Flexible Generation on Fossil-fueled Generators for Western Electricity Coordinating Council

WESTERN ELECTRICITY COORDINATING COUNCIL
Attn: Tyler Butikofer, P.E.
Staff Engineer
155 North 400 West, Suite 200
Salt Lake City, UT 84103
TButikofer@wecc.org

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COMPILED BY
Nikhil Kumar
Nikhil.Kumar@intertek.com
(+1) 408-745-7000

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Issuing Office

Intertek AIM
3510 Bassett Street
Santa Clara, CA 95054
408-745-7000

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1 | Introduction

The addition of variable generation (VG) places new constraints and costs on conventional generation of power in utility systems, particularly due to an increase in the variability and uncertainty associated with VG. There is a need to include the change in reliability and cost of operating fossil-fueled power plants with operating patterns that include increased generator flexibility.

Fossil-fueled power plants operated in flexible mode are likely to have increased wear and tear on the equipment and/or reliability impacts that do not necessarily occur if the plants were run in baseload operation mode. This is particularly true for power plants designed for baseload operation. A power plant designed for baseload operation typically operates at full load for long periods of time between cold shutdowns. Critical components operate at design temperatures, with temperature imbalances which occur only at that load. Startups and shutdowns are infrequent, and the load ramp rates consistent, so fatigue damage is less of a concern.

Flexible or cycling operation, on the other hand, requires several different modes of operation: two-shifting, load following, and low load operation, as well as frequent startups (hot, warm, and cold), faster ramp rates, and more thermal cycles than originally designed for. Temperature imbalances may be exacerbated by operation at non-optimum, non-design loads. Temperature differences between components may cause flexibility issues and subsequent fatigue damage.

The Western Electricity Coordinating Council (WECC) and the Production Cost Model Data Work Group are seeking to update the estimate of the cost of flexible generation and reliability impacts on the conventional fossil-fueled generators for operation in calendar year 2030.

Intertek AIM (previously Aptech Engineering Services) had provided an estimate of increased wear and tear costs and reliability impacts to WECC [Intertek Project AES 11077831-2] and National Renewable Energy Laboratory (NREL) [Contract No. DE-AC36-08GO28308].[1]

In our previous study, Intertek AIM had organized the results by the following eight generator plant types in the following eight groups:

1. Small coal-fired sub-critical steam (35-299 MW)
2. Large coal-fired sub-critical steam (300-900 MW)
3. Large coal-fired supercritical steam (500-1300 MW)
4. Gas-fired combined-cycle plants (combustion turbine (CT)-steam turbine (ST) and heat recovery steam generators (HRSG)
5. Gas-fired simple cycle large frame (GE 7/9, N11, V94.3A, and similar types)
6. Gas-fired simple cycle Aero-Derivative CT (LM 6000, 5000, 2500)
7. Gas-fired steam (50-700 MW)
8. Retrofitted coal-fired steam (plants retrofitted to provide load following or regulation) – these plants should be parsed by size/type same as Types 1 through 7.

[1] https://www.nrel.gov/docs/fy12osti/55433.pdf

The primary task of the study included the estimation of "lower bound" cycling cost data for the above identified groups of generator plant types, including the following:

- Hot, warm, and cold start costs
- Baseload variable operations and maintenance (VOM) costs

Figure 1 was a key output of the analysis showing the spread of cycling-related costs.

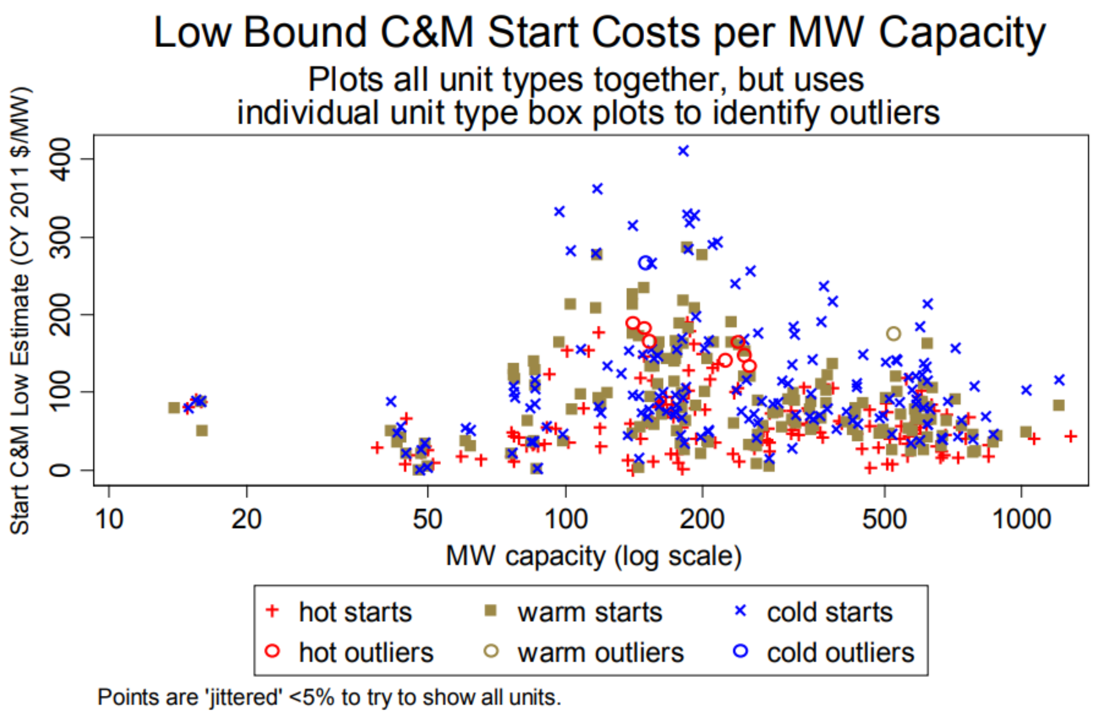

Figure 1 — Lower Bound – Capital and Maintenance Start Costs per MW Capacity.

Background

Since Intertek AIM and WECC collaborated on this work in 2011, several changes have occurred with respect to power plant operating profiles and technologies. Further, different regions in the U.S. have witnessed different outcomes from the integration of VG.

A combination of market deregulation, increasing VG, changes in fuel prices, and other factors have forced operators to cycle aging fossil units that were originally designed for mainly base load operation. As shown in previous studies, all fossil generators can perform cycling operation, but the impact of cycling on wear and tear cost or damage and the reliability of the plants from the cycling differs from one unit to another (see figure 1).

Intertek AIM has performed evaluation of the evolving operating regime of several hundred power plants in the U.S.[2] As an example, Figure 2 shows the change in operating mode of the fossil generation fleet in California from 2005 to 2015. The change in operating profile is largely driven by the rapid increase in solar generation in the state. Solar generation in the state forces the natural gas fleet in California (about 40% of capacity) to operate with increased cycling. Fossil units are staying offline for more hours in 2015 compared to 2005, and when they are online, they typically ramp up to full load (as solar generation falls at night). There is also a trend of increased operating hours at lower loads in 2015 versus 2005.

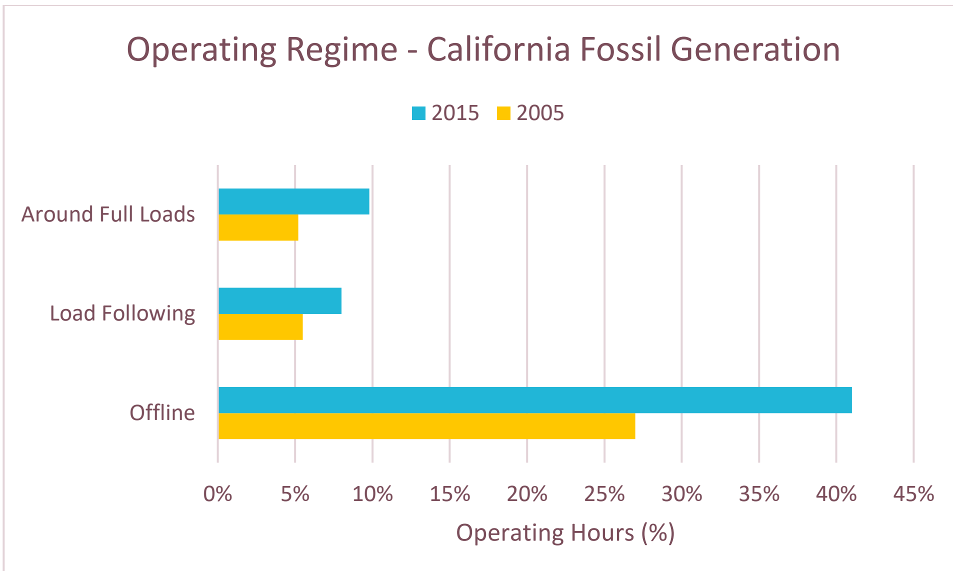

Figure 2 — Operating Regime of California Fossil Generators (2005 vs. 2015).

Characterizing fossil power generation impacts from large VG on the grid requires an understanding of the operating regime of the power plants. Further, the analysis should cover a long enough time horizon to account for the "time lagged" wear and tear damage on fossil generation equipment. When a power plant is relatively new, there is a much larger time lag between increased cycling and failures, compared to an older plant[3]

Flexible generation or cycling refers to the operation of electric generating units at varying load levels, including on/off and low load variations, in response to changes in system load requirements. Every time a power plant is turned off and on, the boiler, steam lines, turbine, and auxiliary components go through unavoidably large thermal and pressure stresses, which cause damage. This damage is made worse by the phenomenon we call creep-fatigue interaction. Creep and fatigue are terms commonly used in engineering mechanics. Creep is time-dependent change in the size or shape of a material due to constant stress (or force) on that material. In fossil power plants, creep is caused by continuous stress that results from constant high temperature and pressure in a pipe or tube occurring during

[2] Impact of Large-Scale Wind & Solar Integration on Existing Fossil Generation in United States, N. Kumar et al., 15th Wind Integration Workshop, Vienna (2016)

[3] "Power Plant Cycling Costs," N. Kumar et al. http://www.nrel.gov/docs/fy12osti/55433.pdf.

steady-state base load operation. Fatigue is a phenomenon leading to cracking and possible fracture (failure) when a material is under repeated, fluctuating stresses. In a fossil power plant, such fluctuating stresses result from large transients in both pressures and temperatures. The worst of these transients typically occur during cyclic operation. Because base load fossil units are designed to operate in the creep range, they experience increased outages when they are additionally subjected to cycling-related fatigue. The term creep-fatigue interaction suggests that the two phenomena (creep and fatigue) are not necessarily independent, but act in a synergistic manner to cause premature failure. In fact, materials behave in a complex manner when both types of stresses occur.

Relating this discussion to power plants, if an older, base loaded plant (that used to have three to six starts per year and is at 40 to 80% design life from creep damage) is now suddenly dispatched to operate at 50 starts per year, it may take only 2 to 6 years to cause component failures. Thus, while cycling-related increases in failure rates may not be noted in the first months, critical components will eventually start to fail. Shorter component life expectancies will result in higher plant equivalent forced outage rates (EFOR) and/or higher capital and maintenance costs to replace components at or near the end of their service lives. In addition, cycling increases may result in reduced overall plant life. How soon these detrimental effects will occur will depend on the amount of creep damage present and the specific types and frequency of the cycling.

As a power plant ages, the equipment degrades even though it is maintained and inspected and is unable to perform as well as brand new equipment. It becomes necessary to upgrade or replace degraded equipment to “new condition”. For example, even though condensers are cleaned annually or more often, condenser retubing becomes necessary every 10 or 15 years. In other words, maintenance is necessary to minimize the effect of equipment degradation with age and operating regime. With cycling operation, some components face accelerated life degradation from the effects of aging and the off-design operations.

Capital expenses, as well as variable and fixed operations and maintenance (O&M) costs at a generating facility, can be analyzed to assess maintenance and equipment replacements at a power plant and determine the current condition. Costs associated with plant cycling and the impact of the cycling on reliability can also be gauged and quantified. Plants that have underspent on capital and/or O&M are likely to suffer with lower historical reliability or are at risk of future forced outages.

The unit’s specific analysis results depend heavily on the regression analysis of the costs versus cycles and the unit signature data during cyclic operations including the range of all load changes. A comprehensive methodology to determine the cost associated with plant cycling has been discussed in recent renewable integration studies.

The increased incremental costs that are attributed to cycling are broken down into the following categories[4]:

1. Increases in maintenance and overhaul capital expenditures.
2. Forced outage effects including forced outage time, replacement energy, and capacity.

[4] Lew, D.; Brinkman, G.; Ibanez, E.; Florita, A.; Heaney, M.; Hodge, B.-M.; Hummon, M.; Stark, G.; King, J.; Lefton, S.A.; Kumar, N.; Agan, D.; Jordan, G.; Venkataraman, S. (2013). The Western Wind and Solar Integration Study: Phase 2. NREL/TP-5500-55588. Golden, CO: National Renewable Energy Laboratory. Accessed May 2, 2014: http://www.nrel.gov/docs/fy13osti/55588.pdf.

3. Efficiency, both long-term losses as well as operational losses associated with startups and low/variable loads.
4. Cost of startup fuel, auxiliary power, chemicals, and extra startup manpower.

Report Goals

WECC's Production Cost Model Data Work Group required Intertek AIM to update the cost and reliability impacts estimated in the 2012 study for modes of operation in calendar year 2030.

The following technical approach was used to quantify the wear and tear cost impacts:

- Characterize historical operations of thermal units within WECC.
- Evaluate and control for recent and projected power plant Capital Expenditures (CapEx) and Operating Expenditures (OpEx)
- Calculate changes to cycling duty and the potential impacts on wear and tear costs, as well as reliability impacts.

The results presented in this report include the following generation types:

1. Small coal-fired sub-critical steam (35-299 MW)
2. Large coal-fired sub-critical steam (300-900 MW)
3. Large coal-fired supercritical steam (500-1300 MW)
4. Gas-fired steam (50-700 MW), includes both supercritical and subcritical technologies
5. Gas-fired simple cycle large frame (GE 7/9, N11, V94.3A, and similar types)
6. Gas-fired simple cycle Aero-Derivative CT (LM 6000, 5000, 2500). New data set to include, New Fast Start Gas Turbines – Aero-Derivative (LMS 100 and similar)
7. Gas-fired combined-cycle plants (CT-ST and HRSG) – Conventional[5]
8. Gas-fired combined-cycle plants (CT-ST and HRSG) – High Efficiency Gas Turbines (H Class and Similar)
9. Gas-fired combined-cycle plants (CT-ST and HRSG) – Fast Start
10. Gas Reciprocating Engines

Intertek AIM has limited the sample size of units to the Western Interconnect where reasonable; however, we have included other U.S.-based power plants if sample size is small.

[5] F-Class based machines. F-class turbines are typically in the 170-230 MW range. Products include GE's 7F.03-.05 models, Siemen's SGT6-5000F, and Mitsubishi Hitachi's M501F

The results of the projected 2030 cost of cycling and reliability impacts will be provided in the following format:

- **Hot, Warm, and Cold Start Costs**

  Costs per start for hot, warm and cold starts (2020$).

  Physical Constraints: Intertek AIM will also provide typical ramping capabilities, minimum up and down time, startup time for the different generation technologies, and the corresponding cost impacts.

- **Load Following Costs**

  Costs for various load following modes – mild, significant, and operation at minimum load (2020$).

  Minimum load operation to be evaluated may be at approximately 80%, 50%, and 30% of maximum load. Generation technologies that are unable to operate below any minimum load operation described above will be noted. These costs will inherently include all cycling-related costs (except forced outage costs).

  Physical Constraints: Ramping capabilities at various low loads will be listed, including cost impacts.

- **Base-loaded Variable O&M Costs**

  Intertek AIM determines the cycling-related O&M cost (listed above) and subtracts that from the total O&M costs to generate a baseload VOM cost. These costs assume a power plant running at steady load without any on/off cycling. This will ensure no double counting of VOM costs in WECC's production cost modeling.

- **Reliability Impacts**

  While cycling, increases in failure rates may not be noted immediately, critical components will eventually start to fail. Shorter component life expectancies will result in higher plant EFOR and/or higher capital and maintenance costs to replace components at or near the end of their service lives. Intertek AIM will provide the expected "lower-bound" increase in EFOR (in added percentage for a single year) due to each cycle type.

2 | Flexible Generation Costs and Reliability Impacts

Calculated cycling costs for typical load cycles of any power plant unit are recorded by Intertek AIM as the total present-valued future cost of the next "incremental" cycle.

These numbers are best estimates based on the assumption that the overall amount of cycling (i.e., equivalent hot start (EHS) per year) continues at no more than 75% of the level of past operations. If the amount of cycling of a given unit increases dramatically, the cost per cycle would also increase due to nonlinear creep-fatigue interaction effects.

However, if CapEx and OpEx spend is reduced for any reason, such as an impending retirement of the asset, then the net cost of cycling is reduced. The reduced spend will manifest as reduced reliability. Such trends have been observed at other sites assessed by the author.[6]

Basic Premise

Maintenance requirements are based on an assessment of hours of operation or cycling of a unit (besides any reactionary events). Major costs for each inspection are for labor, consumables, and capital replacement parts. Labor is the extra manpower needed to perform the inspection. The consumables are material which will be used during the inspection or maintenance activity, such as gaskets, welding products, etc. Capital replacement parts are the parts that are examined for corrosion and wear during each inspection. Generally, the capital replacement costs dominate the overall ratio of costs, as this is primarily to counter for the life shortening effects of aging or additional cycling.

Cost is one of the key factors influencing the choice of fuels and technologies used to generate electricity. Capital, maintenance, operating, and financing costs often vary significantly across technologies and fuels. In addition, regional differences in construction, fuel, transmission, and resource costs mean that location also matters. Because electricity prices differ throughout the day, the timing of a plant's output affects its cost recovery.

The underlying premise of Intertek AIM's approach is that cycling directly causes a significant proportion of annual non-fuel unit costs. For economic modeling, the independent cycling-related variable was taken to be equivalent hours of operation.

Costs per Start

The desired result is an estimate of the cycling cost elements combined to determine the effect of an additional equivalent start. Intertek AIM's methodology brings all future forecasted costs to their present value using the client's discount rate, cost escalation factor (or simply inflation rate), and aging effects.

[6] Cochran, Jaquelin, Debra Lew, and Nikhil Kumar. Flexible Coal: Evolution from Baseload to Peaking Plant. NREL, 2013 https://www.nrel.gov/docs/fy14osti/60575.pdf

The present value of future wear and tear cycling costs for the plant equipment is the sum of two components: added costs and accelerated costs:

- Specifically, the first component, adding costs, is the cost of extra cycling-related maintenance necessary to avoid shortening of the component's life caused by an additional start.

- The second component, accelerated costs, is the cost of "moving up" future maintenance costs in time (i.e., maintenance costs occur sooner) caused by adding one "start". Adding a "start" to a unit's operation will cause the time required before maintenance is needed to decrease. Thus, this second component represents the present value of the acceleration of costs incurred for ordinary maintenance costs due to an additional start, especially overhaul costs and other large non-annual costs.

Further, it is important to highlight the impact of life shortening as a result of increased flexible operation. Increased cycling can have a significant life-shortening impact on certain units. This cost element can be significant for units that are near their end-of-life, but less important in cases of planned retirements. Note that as long as capital and maintenance expenditures are made to counter cycling effects, this cost element will be small compared to such costs as maintenance and extra fuel. In other words, the cost of maintenance is essentially countering the effects of life shortening over time.

It is important to note that since not all subsystems have the same life expectancy; targeted spending patterns for critical subsystems are required. Intertek AIM looks at both total spending and spending patterns to determine if current and projected critical subsystem spending is enough to maintain efficiency and reliability.

Table 1 provides definitions of costs included in the wear and tear estimates.

Table 1 — Definitions of the Cycling-related Costs

	Cost Includes	Cost Excludes
Cost of O&M	• Operator non-fixed labor • General engineering and management cost (including planning and dispatch) • Maintenance and overhaul maintenance expenditures (preventative and scheduled) for boiler, turbine, generator, air quality control systems, and balance of plant key components	• Fixed labor • Fixed maintenance and overhaul maintenance expenditures for boiler, turbine, generator, air quality control systems, and balance of plant key components • Preventative maintenance and routine maintenance on auxiliary equipment like buildings, HVAC, etc.
Cost of Capital Maintenance	• Overhaul capital maintenance expenditures for boiler, turbine, generator, air quality control systems, and balance of plant key components	• Replacement due to obsolescence • Preventative maintenance and routine maintenance on auxiliary equipment like buildings, HVAC, etc.

Damage Modeling & Cost Estimation

Intertek AIM's full comprehensive top-down and bottom-up methodologies for estimating cycling costs provide better and high confidence estimates, which require extensive cost and operational data. That approach models the relationship between total cycling costs (wear and tear, EFOR, startup costs, etc.) and historical cycling operations for the unit or plant. To set up and run a complete cost of cycling program, we require 8 to 10 years of cost and hourly megawatt and plant reliability data as a minimum. In the absence of these required considerable data, we have found that a reasonable (though less accurate) method is to "benchmark" or measure the cost estimates from those units against those from similar units previously analyzed for which we have completed the more rigorous cost estimate methodology with detailed information.

Figure 3 shows the overview of our process to estimate lower bound cycling costs.

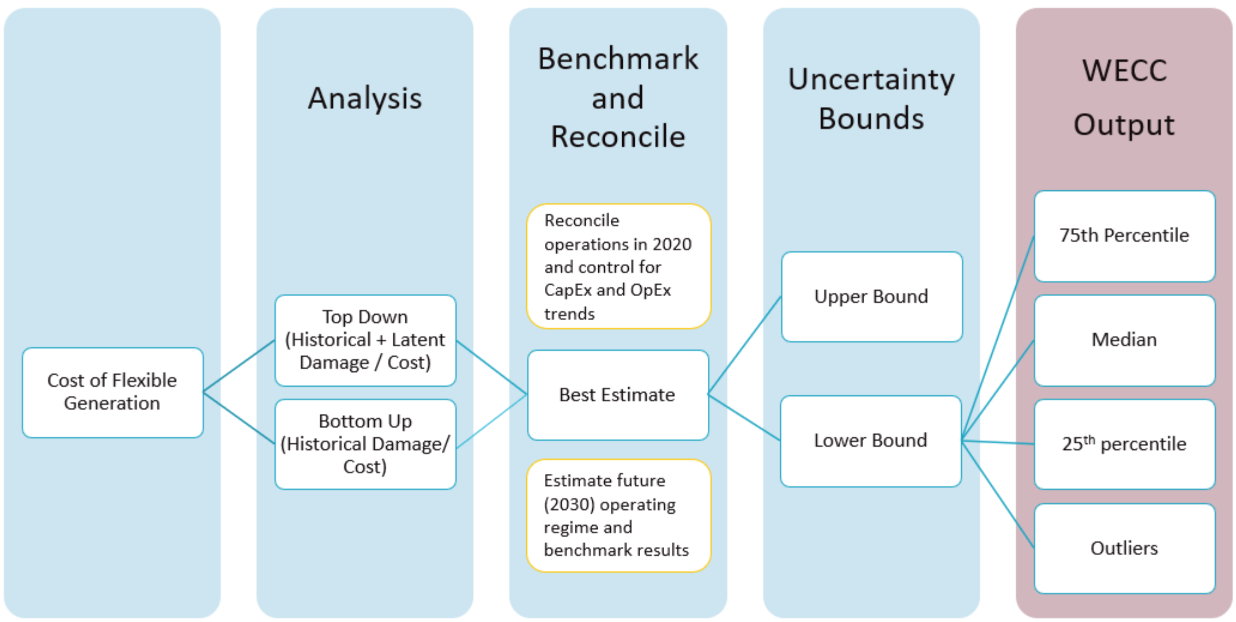

Figure 3 — Lower Bound Cost Estimation Methodology.

To establish the reference unit cycling costs, we used our top-down methodology. We used elaborate statistical models to develop "lower bound" estimates of the total unit equipment damage costs due to cycling, which include the incremental wear and tear costs and the capitalized maintenance and O&M costs in the full-blown, top-down cost of cycling analysis. The results of these statistical analyses are then used as benchmarks for calculating the cycling costs presented in this report.

The control variables in our benchmarking approach are listed below:

- Size — We defined size by the megawatt capacity of generators for the unit (for combined-cycle units, we sum the capacities of the ST and gas turbine(s)).

- Cycling rate and age — These factors account for unit age and for differing annual and cumulative rates of cycling damage expressed in EHS, as measured using Intertek AIM's damage algorithm – Loads Model[7].
- Vintage and design characteristics — Some technologies are better suited to operate flexibly (example, gas turbines or reciprocating engines).
- Typical cycle damage ratio (in units of EHS per cycle) — The ratio of the average damage for the subject unit's start or load follow to that of the benchmark unit; again, as estimated using the Loads Model, the cycle ratios for each start type (hot, warm, and cold) and load follow are considered, along with typical load follows.
- Annual plant maintenance costs — Plant maintenance and capitalized maintenance costs of benchmarked units were compared to the top-down reference unit costs.
- Reliability — Flexible operation, as well as aging of equipment, influence reliability.

Operating Profile of Different Generation Technologies

An important step in estimating cycling costs and reliability impacts is to characterize the operating regime of the 10 groups of generation technologies. The next series of charts shows the operating regime of the coal steam and combined-cycle generation technologies over a 20-year horizon. Highlights from the analysis are:

- On average, the coal steam units have not witnessed increases in on/off cycling; however, they are operating with increased load following. Figures 4 and 5 highlight the operation of the sample of subcritical coal units within WECC. Evidently both the large and small coal units are operating more hours at lower loads in the recent years, and while the number of starts has not trended higher, when the units do go offline, they stay off for longer periods (cold starts).
- Simple cycle CTs continue to perform as peaking units, with low capacity factors. The generation peaks in the summer months as expected and shown in Figure 6.
- The combined-cycle fleet, with lower natural gas prices and a growing share of the overall grid capacity have transitioned to more baseload operation. Figure 7 shows the annual starts for a sample of conventional combined-cycle, newer high efficiency and fast start combined-cycle units.

[7] An EHS is Intertek AIM's unit of cycling intensity. One normal hot start and shutdown cycle would produce about one EHS. One abrupt hot start with especially damaging ramp rates and other load range characteristics would produce well over one EHS, as would most warm starts and all cold starts. The usually more numerous load follow cycles each typically produce a small fraction of an EHS.

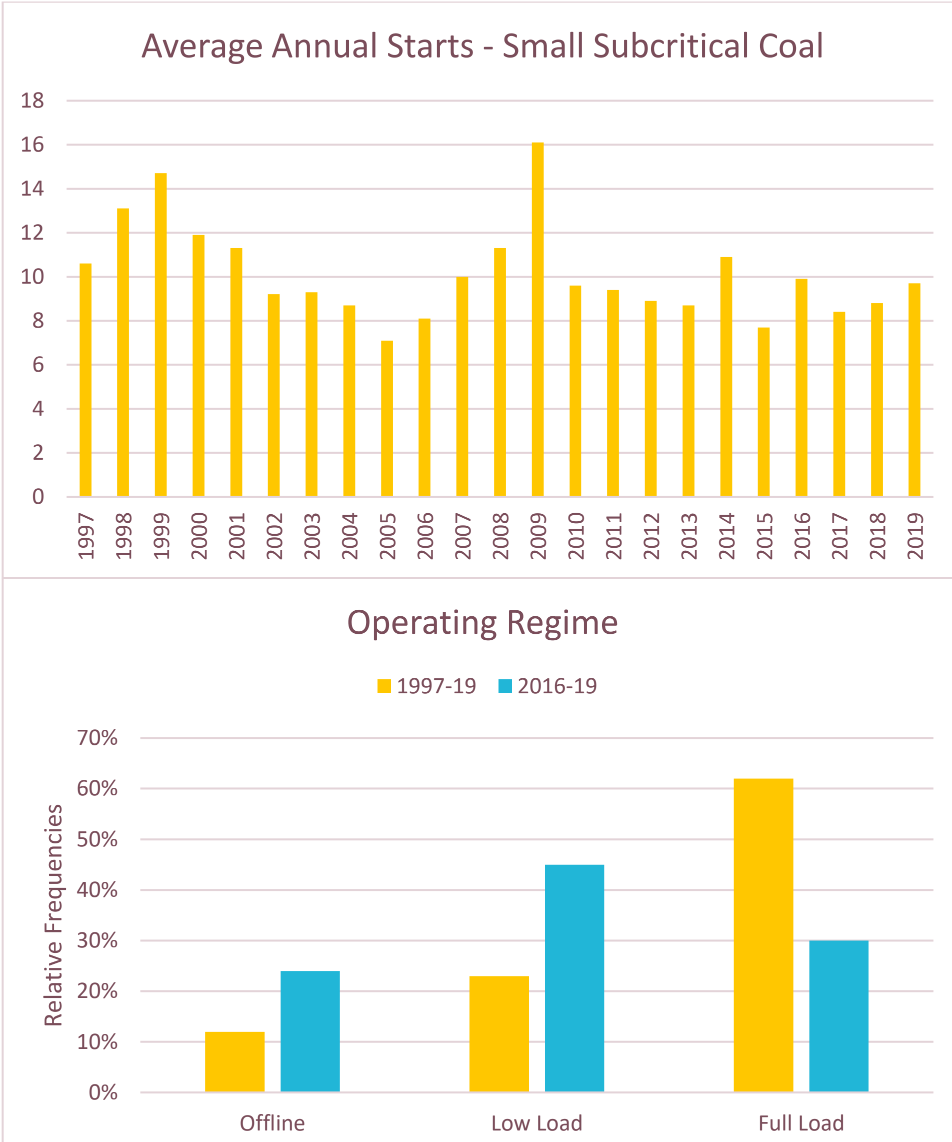

Figure 4 — Small Subcritical Coal (<300 MW) Operating Regime.

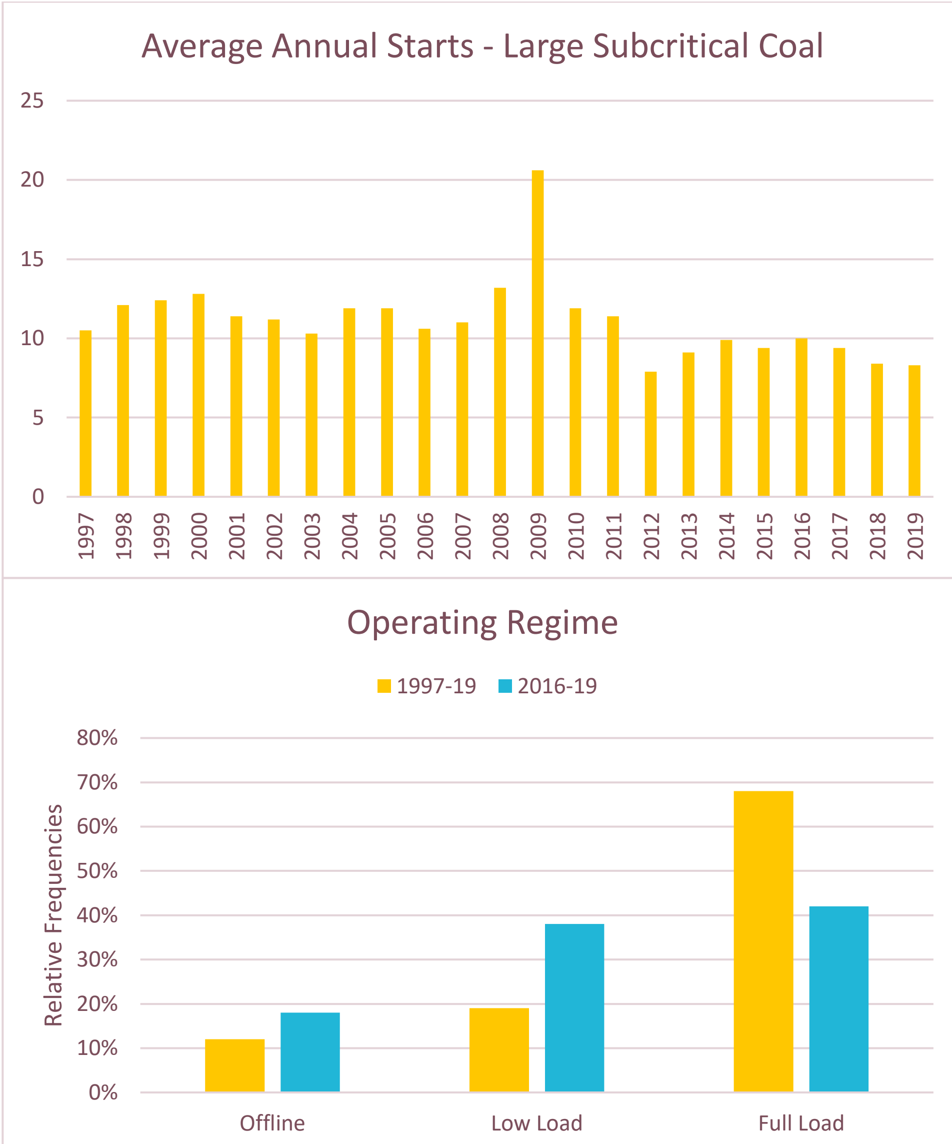

Figure 5 — Large Subcritical Coal (>300 MW) Operating Regime.

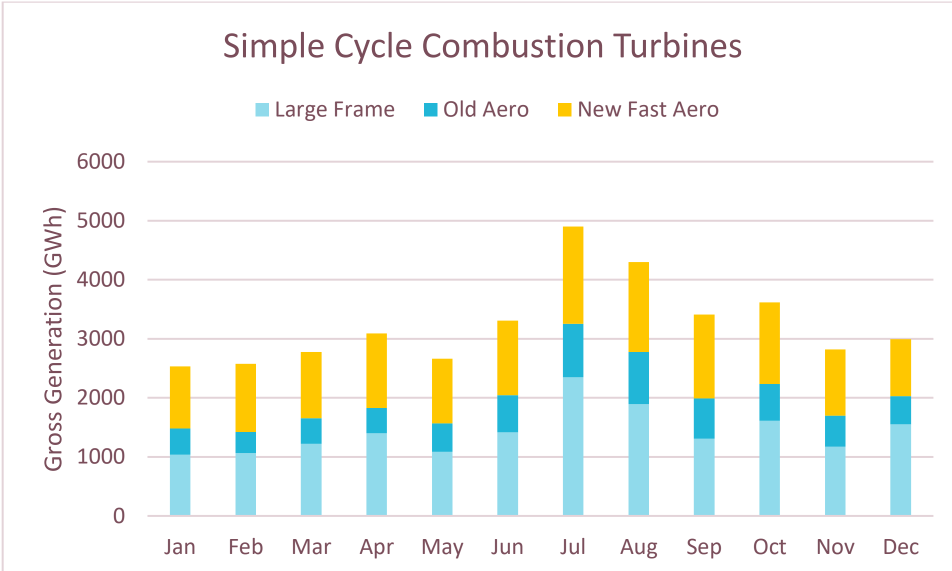

Figure 6 — Simple Cycle CT Monthly Operating Regime.

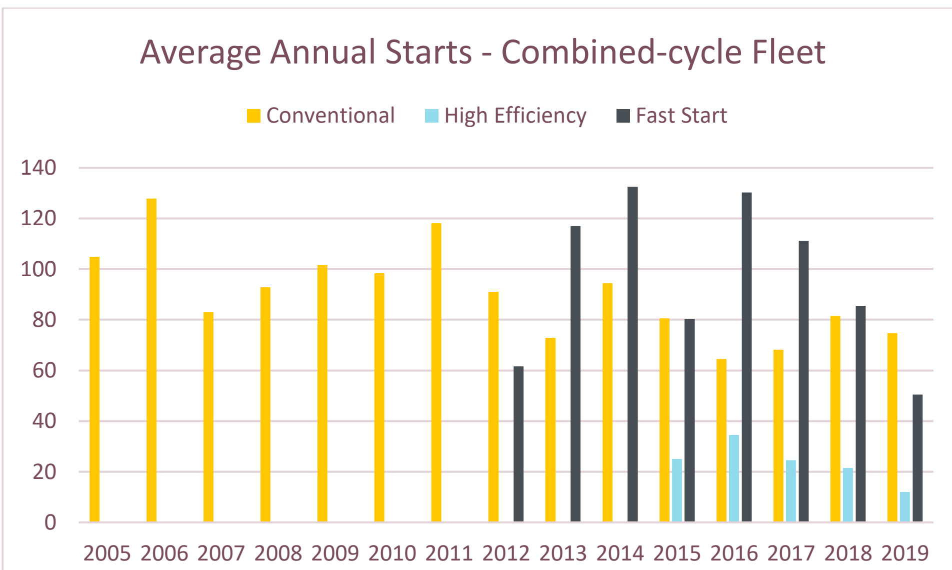

Figure 7 — Annual Starts – Combined-cycle Fleet.

Flexible Generation Impacts and Results

Power plant operations that start, stop, cycle, two shift, base load, and operate above a unit's rating have a quantifiable impact on component life and on total associated unit operating costs. The true costs of cycling and low load operations are often not known or not well understood because of the complex effects of these operations on additional capital and/or maintenance spending requirements, increased EFOR, increased heat rate, and reduced life effects.

Figure 8 shows a risk chart from a small sample of units that show a relation between cycling and forced outage rates. To help reduce the clutter in the chart, some key units have been highlighted to illustrate the impact of cycling on forced outage rates for different design units[8].

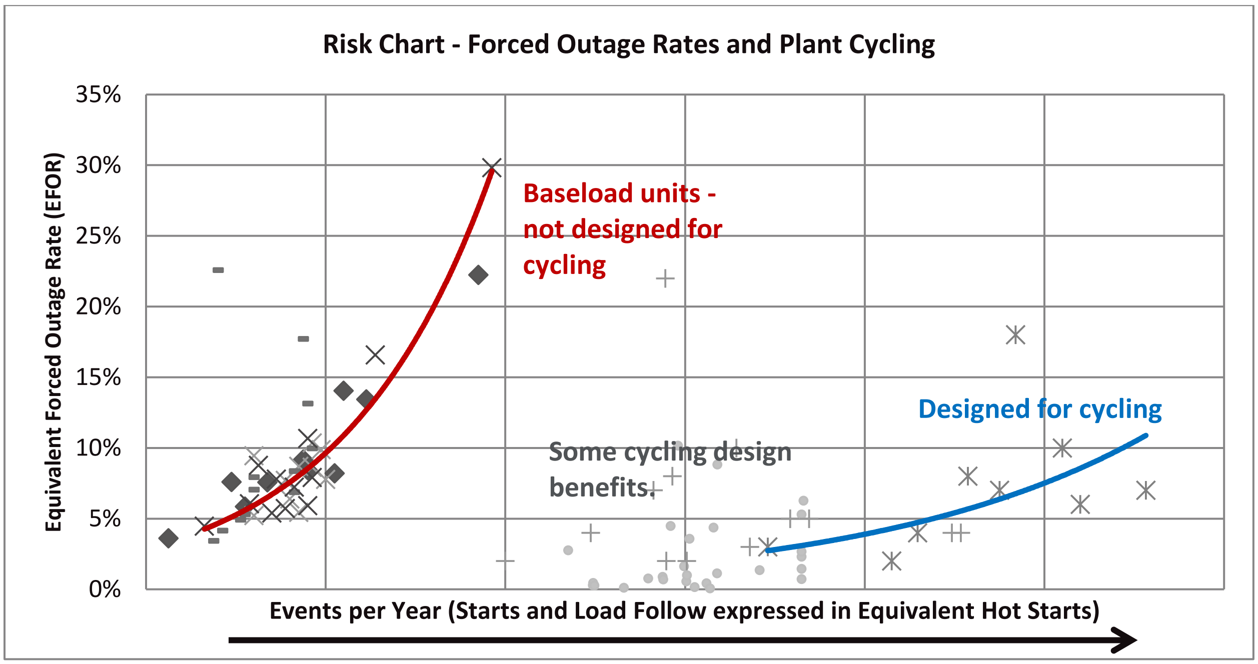

Figure 8 — Flexible Generation and Reliability Impacts.

Even when a unit is thought to be properly designed for cycling, there are external effects in the balance-of-plant design, water chemistry, etc., that make some units more susceptible to cyclic damage than others.

Another risk factor for an aging fleet of fossil generators is High Impact Low Probability (HILP) events. With increased cycling and an aging plant, operators of older assets, conventional steam as well as older combined-cycle units, are putting the units at increased risk of increased forced outages and HILP events. Older units have a much higher chance of experiencing HILP-related forced outages. Figure 9 shows hazard rates for aging power plants. Intertek AIM analyzed NERC GADS data and defined a HILP as a full forced (i.e., unplanned) outage greater than 350 hours.[9]

[8] Impact of plant cycling on availability, N. Kumar et al., ASME Power 2015, POWER2015-49359

[9] Impact of Aging on Power Plant Reliability, N. Kumar and P. Besuner, Intertek Engineering Technical Paper 214

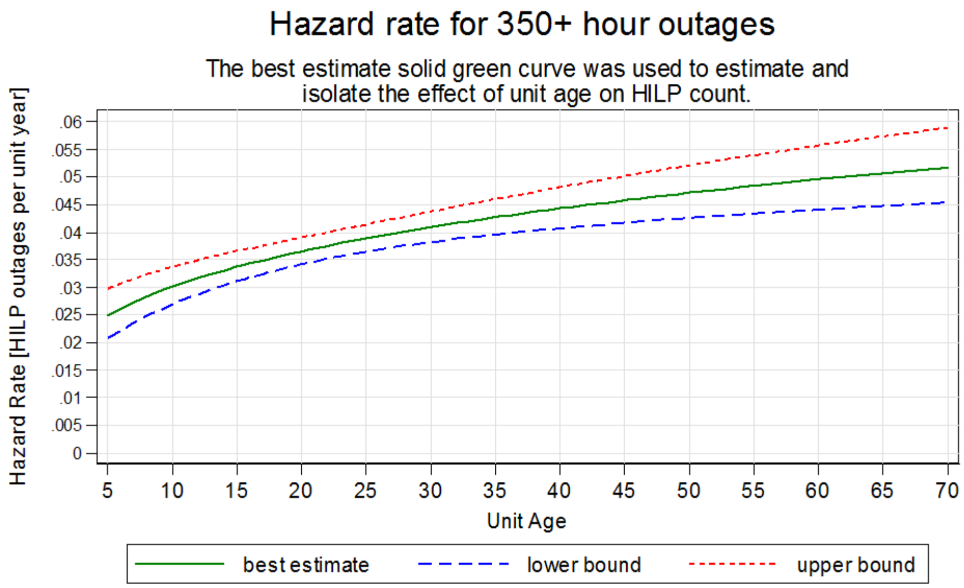

Figure 9 — Hazard Rate for HILP Outages.

Costs associated with plant cycling and the impact of the cycling on reliability can also be gauged and quantified. As a power plant operates with increased cycling and ages, the equipment degrades even though it is maintained and inspected and is unable to perform as well as brand new equipment. It then becomes necessary to upgrade or replace degraded equipment to "new condition."

Increased maintenance spend is necessary to minimize the effect of equipment degradation with age and changing operating regime. Plants that have underspent on capital and/or O&M are likely to suffer lower historical reliability or are at greater risk of future forced outages. As discussed earlier, Intertek AIM assessed the existing fleet operations within WECC to estimate accumulated cycling damage, and then benchmarked cost of flexible generation to reference units in our database. Over time, most North American operators have tended to minimize O&M spend.

Figure 10 shows the historical trend of real O&M for all plants and weighted by generation has decreased from 1990-2005 and has leveled out in recent years. Highlights of our analysis are discussed below: [10]

- While O&M spending is levelling off, capital costs are much higher than any other costs covered in our analysis. Essentially, even with extensive maintenance, the performance of the equipment will deteriorate over time to the point where it must be replaced.
- Coal power plant O&M has not been very high but there are some signs of increased coal O&M among the oldest plants. This tendency to keep O&M costs down for coal plants may also explain Intertek AIM's observation and analysis of increased forced outages with age.
- Combined-cycle units tend to have lower O&M spend, particularly in recent years.

[10] Power Plant O&M Spend in U.S. – Trends and Impact, N. Kumar & P. Besuner Intertek Technical Paper 305

- There are observed variations in O&M costs by state. California is an exception to low overall western state O&M costs, with moderately high O&M spending; but well below that of some of the highest O&M states in the U.S.

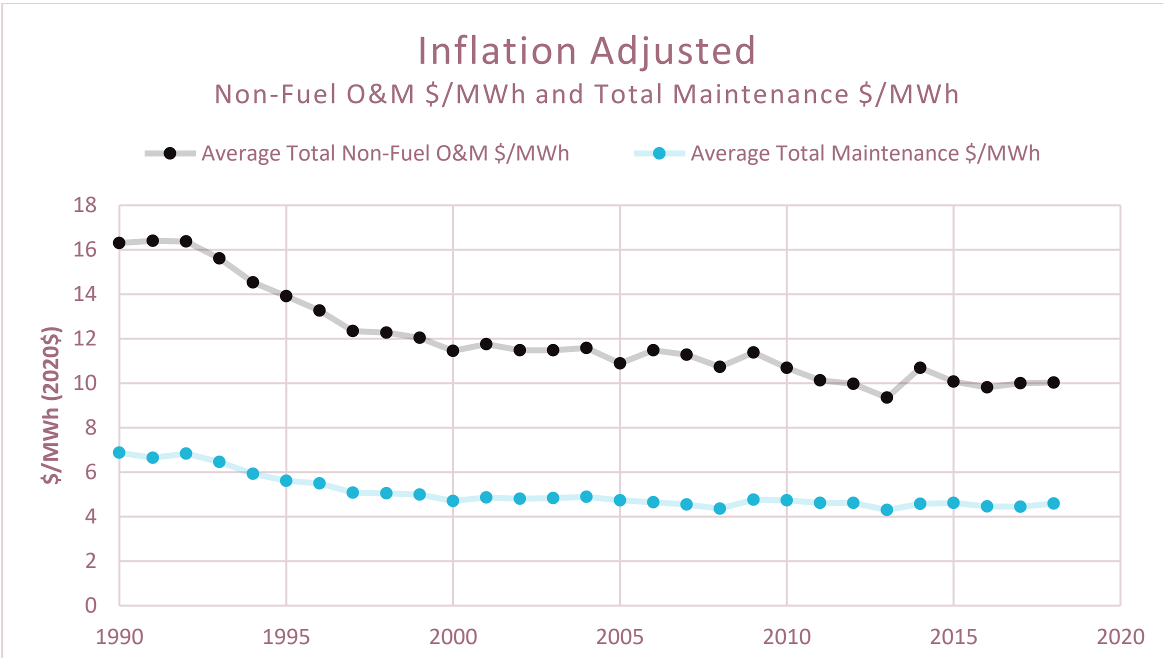

Figure 10 — Historical Non-fuel O&M Spend.

Finally, we referenced the U.S. Energy Information Administration (EIA) Annual Energy Outlook 2020 to forecast likely operating regime of the various fossil generation technologies in 2030[11].

The general trend discussed by the EIA, and our own assessment forecasts that:

- While there will be additional coal generation retirements by 2030, the remaining higher efficiency (thermal or economical) coal units will tend to operate similar to how they operate in 2016-2019 (Figures 4 and 5). However, these units are likely to suffer from lower O&M spend, increased offline hours, and deterioration of reliability as these units age.
- Simple cycle CTs and reciprocating engines are designed for cycling operation, and the operating profile will not differ significantly in 2030. Also, by definition, a majority of the VOM spend on these units is associated with cycling operation, which is reflected in our results.
- Conventional combined-cycle units would have accumulated several thousand hours of operation, as these units continue to operate more baseload. By 2030, several of these units would be over 25 years old, with competition from newer higher efficiency units, and therefore likely to operate with more on/off cycling. Per the EIA, "The currently most common combined-cycle units, with their

[11] https://www.eia.gov/outlooks/aeo/

lower efficiency, and the new single-shaft (1 x 1 x 1 configuration) combined-cycle units decline in utilization as a group, from 56% in 2020 to 36% by 2035".

- Fast start combined-cycles will see modest increase in on/off cycling, while the higher efficiency combined-cycle fleet will predominantly operate as they do now.

Results

Table 2 shows the physical constraints and capabilities of the ten (10) generation types analyzed:

- As expected, the simple cycle aeroderivative CTs and the reciprocating engines provide significant flexibility, with fast ramping capabilities and relatively short down times. Reciprocating engines have extremely fast ramp rates and can get up to full load at a ramp rate of 50% (as a percent of Gross Dependable Capacity (GDC)) per minute. Large frame CTs are not quite as flexible as aero derivative machines.
- Coal units have improved the low load capabilities, and more so on the larger subcritical coal units. Coal steam units are limited in terms of gas/oil support availability and/or number of mills in operation at low loads. Larger units have been able to improve low load operation from about 50% in the past to about 35-40% minimum load (as a percent of GDC). Coal units are also less flexible in terms of startup times and up times. Some units have been transitioning to sliding pressure operation, which may limit ramping response.[12]
- The median age of operating gas steam units is over 55. Most of the units in WECC are subcritical and have low capacity factors (<30%). Typically, these units perform no more than 40 starts a year and are utilized infrequently. The units can operate at low loads (around 20-30%) for extended periods of time but are not as efficient and used sparingly. These units are also operated with ramp rates that are significantly higher than coal steam units.
- Combined-cycle units typically have a minimum emissions compliance load, which limits the operating range. Multiple gas turbine configuration on these units lend increased flexibility in operation. Some of the new higher efficiency combined-cycle units are, however, in 1x1 configuration and operate mostly baseloaded. The ST is often a limiting factor for high ramp rates, and unless the plant is designed for cycling operation (e.g., bypass system), the units tend to have some limitations in terms of flexibility.
- Fast start combined-cycle units have HRSGs with a Benson® high pressure section or are single-pressure non-reheat units that minimize damage on the components. These units also might take advantage of the shutdown purge sequence (in compliance with NFPA® 85) to improve startup times.
- The high efficiency combined-cycle units can achieve efficiencies in excess of 60%. These units are typically constrained on ramp rates as well as low loads.

The values presented in Table 2 are for typical power plants and do not include units that may have been retrofitted or best in class.

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[12] https://www.babcockpower.com/wp-content/uploads/2018/02/constant-and-sliding-pressure-options-for-new-supercritical-plants.pdf

Table 2 — Capabilities and Physical Constraints of Fossil Generators

Unit Types	Coal - Small Sub Critical	Coal - Large Sub Critical	Coal - Super Critical	Gas - Steam	Gas - Large Frame CT	Gas - Aero Derivative CT	Typical CC [GT+HRSG+ST]	High Eff. - CC [GT+HRSG+ST]	Fast Start - CC [GT+HRSG+ST]	Gas - Recip. [per Engine]
Time (min)										
Minimum Up Time	720	720	1440	120	60	60	120	120	60	30
Minimum Down Time	360	480	480	240	60	30	360	480	360	15
Startup Ramp Rate (%GDC/min)										
Typical - almost no diff. by start type	2.0%	3.5%	3.5%	10.0%	10.0%	90.0%	6.0%	5.5%	8.0%	95.0%
Turndown Ramp Rate (%GDC/min)										
Don't see significant changes in rates for level of turndown. However, some steam units use sliding pressure.	5%	8%	8%	20%	15%	90%	10%	10%	15%	95%
Minimum Load (% GDC)										
Typical	40%	35%	45%	20%	50%	50%				-
1x1							48%	48%	48%	
2x1							25%	25%	25%	

Tables 3 and 4 below present the lower bound cycling cost results for the ten (10) unit types for projected operations and annual spend in 2030. As with our analysis in 2012, it should be emphasized that there are large variations in costs between individual units of each type, and that the results provided by Intertek AIM are *low bounds*[13].

All cost numbers in this report have been adjusted for calendar year 2020$.

Use of the generic lower bound costs, without accounting for actual unit operations and spend can result in significant under/over estimation of power plant cycling costs.

Table 3 presents the typical load following costs for three different operating regimes: mild load change (20% of GDC); typical load change (for each unit type); and minimum load operation. Figure 11 presents the same information in a graphical form. The load following costs are not significantly impacted by modest changes to ramp rates. In our assessment for load follow operation, an increase of 25% will have no measurable increase in costs. However, doubling of current ramp rates on the steam units (limited by design) will result in increased costs as indicated in Table 3. For the gas turbine-based technologies, the original equipment manufacturer limits ramp rate capabilities, and typically there is little leeway for operators to increase these rates (without control upgrades, or retrofits).

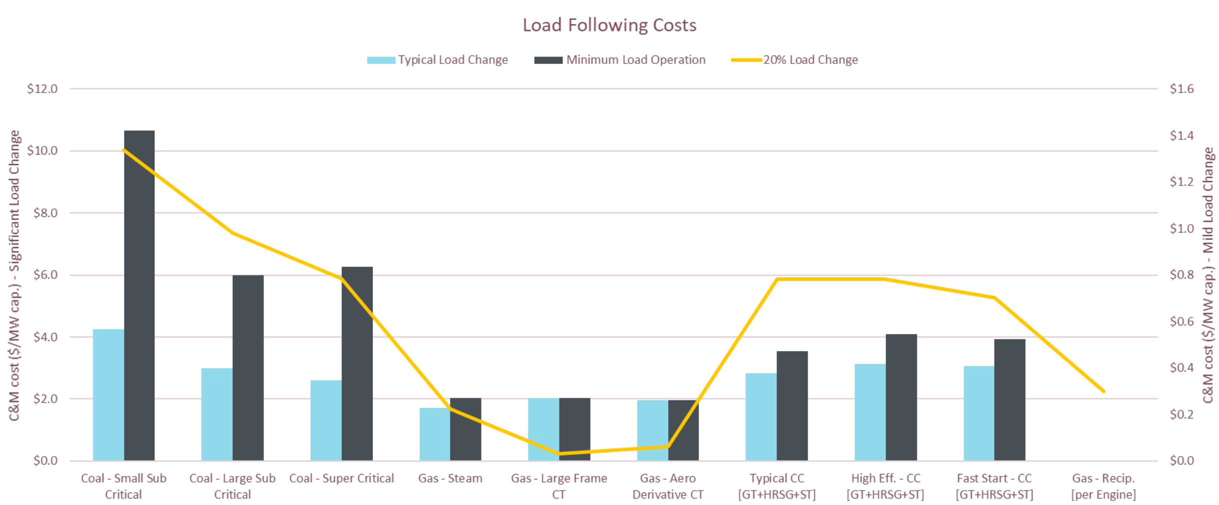


Figure 11 — Load Following Costs.

Note: Mild load change costs are shown on the secondary y-axis.

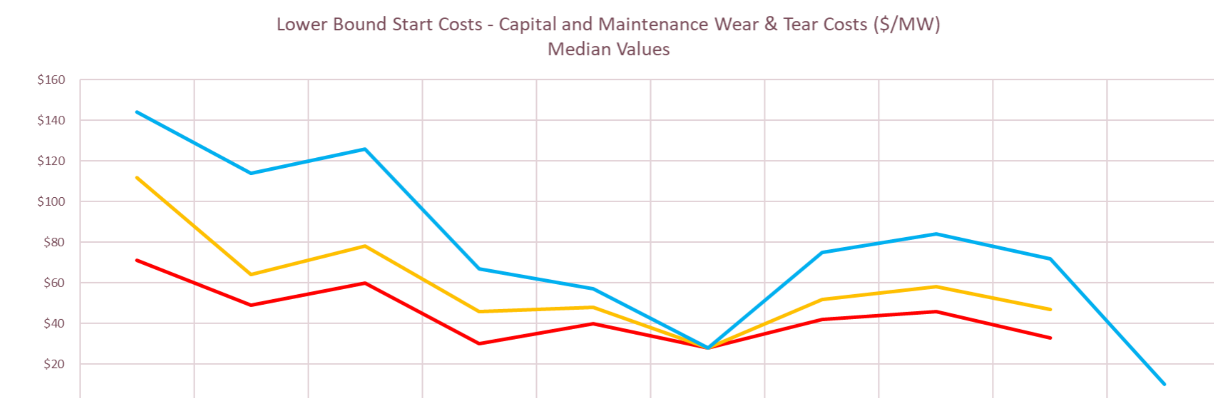
[13] Care should be taken to implement the lower bound cycling cost. For example, if a unit goes through 200 starts per year and the start cost is underestimated by $1,000/start, then the annual cost of this erroneous number can be significant. Moreover, if this unit is indeed cycled on/off more often due to the lower cost estimate, then it would accumulate damage at a significantly higher rate.

Table 3 — Projected 2030 Load following cost estimates (lower bound, 2020$)

Unit Types	Coal - Small Sub Critical	Coal - Large Sub Critical	Coal - Super Critical	Gas - Steam	Gas - Large Frame CT	Gas - Aero Derivative CT	Typical CC [GT+HRSG+ST]	High Eff. - CC [GT+HRSG+ST]	Fast Start - CC [GT+HRSG+ST]	Gas - Recip. [per Engine]
Typical Load Follows Data										
-C&M cost ($/MW cap.) - 20% Load Change										
Median	1.34	0.98	0.78	0.22	0.03	0.06	0.78	0.78	0.70	0.30
~25th_centile	0.76	0.56	0.61	0.14	0.02	0.04	0.37	0.37	0.33	0.25
~75th_centile	1.54	1.24	0.95	0.27	0.05	0.14	0.90	0.90	0.81	0.40
-C&M cost ($/MW cap.) - Typical Low Load										
Median	4.26	2.99	2.61	1.70	2.03	1.96	2.84	3.13	3.06	
~25th_centile	2.44	1.71	2.02	1.04	1.20	1.31	1.33	1.47	1.44	
~75th_centile	4.90	3.79	3.17	2.06	3.57	5.28	3.29	3.61	3.54	
-C&M cost ($/MW cap.) - Minimum Load										
Median	10.66	5.98	6.27	2.02	2.03	1.96	3.55	4.08	3.92	
~25th_centile	6.10	3.42	4.86	1.23	1.20	1.31	1.67	1.91	1.84	
~75th_centile	12.26	7.57	7.61	2.45	3.57	5.28	4.11	4.72	4.53	
							Doesn't include a GT start			
Ramp Rate Effect										
-Typical Range X 1.25	-	-	-	-	-	-	-	-	-	-
-C&M cost ($/MW cap.) - Typical Range X 2										
Median	6.40	5.38	4.70	2.13						
~25th_centile	3.66	1.97	2.33	1.19						
~75th_centile	7.35	11.36	9.51	2.68						

Table 4 below presents the updated cost of starts (and stops) and non-cycling baseload VOM costs for the different generation technologies. Figure 12 presents the start cost per megawatt capacity for each of the generation types graphically (median values). As a reminder, these are 2030 projected costs in 2020$.

Table 5 presents the expected increase in EFOR (in added percentage for a single year[14]) due to each cycle type. Baseload or cycling operation both cause forced outages at plants. Cycling operation can accelerate EFOR, especially on a baseload design power plant. Countering the impact on reliability can only be done by replacing or repairing equipment, that is, increased CapEx and OpEx. This is evident in the results of this study. With lower spending, there is a general trend of increased cycling-related reliability impact. Further, in our experience, we know that cycling-related increases in failure rates may not be noted immediately, but critical components will eventually start to fail as the plant accumulates cycling-related damage. Since a vast sample of the units in 2030 will have accumulated several thousand operating hours, the forecasted impact on reliability is valid, and perhaps conservative considering lower O&M spending.



	Coal - Small Sub Critical	Coal - Large Sub Critical	Coal - Super Critical	Gas - Steam	Gas - Large Frame CT	Gas - Aero Derivative CT	Typical CC [GT+HRSG+ST]	High Eff. - CC [GT+HRSG+ST]	Fast Start - CC [GT+HRSG+ST]	Gas - Recip. [per Engine]
Hot	$71	$49	$60	$30	$40	$28	$42	$46	$33	
Warm	$112	$64	$78	$46	$48	$28	$52	$58	$47	
Cold	$144	$114	$126	$67	$57	$28	$75	$84	$72	$10

Figure 12 — Typical Lower Bound Load Following Costs (Median Values).

[14] For example, Table shows a median (lower bound) EFOR impact of 0.0194% per hot start for small sub critical coal units. Assume that the EFOR = 2% for some future year and the Unit typically sees 10 hot starts annually. If 5 additional hot starts are imposed, the EFOR will be raised to 2.097% (2 + 0.00194*5) for a single near-future year.

Table 4 — Projected 2030 Start Cost and Baseload VOM Costs (Lower Bound, 2020$)

Unit Types	Coal - Small Sub Critical	Coal - Large Sub Critical	Coal - Super Critical	Gas - Steam	Gas - Large Frame CT	Gas - Aero Derivative CT	Typical CC [GT+HRSG+ST]	High Eff. - CC [GT+HRSG+ST]	Fast Start - CC [GT+HRSG+ST]	Gas - Recip. [per Engine]
Cost Item/										
Typical Hot Start Data										
-C&M cost ($/MW cap.)										
Median	71	49	60	30	40		42	46	33	
~25th_centile	71	36	43	25	18		32	35	26	
~75th_centile	130	70	77	47	122		82	99	80	
Typical Warm Start Data										
-C&M cost ($/MW cap.)										
Median	112	64	78	46	48		52	58	47	
~25th_centile	94	52	60	34	19		29	32	26	
~75th_centile	211	82	109	91	131		108	139	96	
Typical Cold Start Data										
-C&M cost ($/MW cap.)										
Median	144	114	126	67	57	28	75	84	72	10
~25th_centile	92	66	85	57	20	11	41	46	39	6
~75th_centile	333	159	154	104	138	66	117	157	112	15
Typical Non-cycling Related Costs										
- Baseload Variable Cost ($/MWH)										
Median	1.79	2.40	3.76	0.29	0.56	0.45	2.10	1.80	1.72	0.00
~25th_centile	1.14	1.62	3.15	0.24	0.47	0.18	1.65	1.27	1.30	0.00
~75th_centile	2.70	3.42	4.79	1.74	1.10	0.66	4.42	4.40	4.53	0.00

Table 5 — Projected Impact of Cycling on EFOR

Unit Types Cost Item/	Coal - Small Sub Critical	Coal - Large Sub Critical	Coal - Super Critical	Gas - Steam	Gas - Large Frame CT	Gas - Aero Derivative CT	Typical CC [GT+HRSG+ST]	High Eff. - CC [GT+HRSG+ST]	Fast Start - CC [GT+HRSG+ST]	Gas - Recip. [per Engine]
Typical Hot Start Data										
-EFOR Impact										
Median	0.0194%	0.0071%	0.0046%	0.0062%	0.0020%		0.0028%	0.0027%	0.0025%	
~25th_centile	0.0045%	0.0035%	0.0030%	0.0015%	0.0007%		0.0021%	0.0021%	0.0021%	
~75th_centile	0.0495%	0.0164%	0.0130%	0.0285%	0.0145%		0.0081%	0.0084%	0.0070%	
Typical Warm Start Data										
-EFOR Impact										
Median	0.0308%	0.0088%	0.0068%	0.0114%	0.0028%		0.0043%	0.0041%	0.0039%	
~25th_centile	0.0058%	0.0059%	0.0059%	0.0025%	0.0007%		0.0023%	0.0023%	0.0023%	
~75th_centile	0.0624%	0.0390%	0.0390%	0.0308%	0.0165%		0.0095%	0.0205%	0.0186%	
Typical Cold Start Data										
-EFOR Impact										
Median	0.0318%	0.0114%	0.0114%	0.0171%	0.0035%	0.0089%	0.0058%	0.0056%	0.0055%	0.0020%
~25th_centile	0.0085%	0.0047%	0.0060%	0.0041%	0.0007%	0.0036%	0.0033%	0.0033%	0.0033%	0.0011%
~75th_centile	0.0652%	0.0300%	0.0202%	0.0467%	0.0118%	0.0199%	0.0091%	0.0215%	0.0195%	0.0031%

3 | Conclusions

Some of the observations from the figures and tables are as follows:

- There is a large spread of cycling costs as well as reliability impacts.
- On a per megawatt basis, small coal units have the highest cost, while the gas reciprocating engines are the lowest cost. This trend is reflected in terms of the reliability impacts also. Small coal units have the most significant impact while reciprocating engines are designed for flexible operation and hence have the least effect.
- Examining the results published by Intertek AIM in 2012, we estimate the cost of hot and warm starts on conventional steam units (subcritical coal and gas steam units), will be slightly lower in 2030 (results are in 2020$). The drivers for the lower start cost are both the expected increase in the different start types, as well as lower overall spend.
- Small subcritical coal will be subject to increased cycling (lower capacity factors), along with reduced total O&M spend similar to recent trends. This increased cycling, as well as aging, results in significant impact on reliability.
- Larger coal units have similar lower future O&M spend but will likely operate in load following mode with extended shutdowns (cold starts). Therefore, cold start costs increase, while other start costs remain similar or lower to results published in 2012.
- Supercritical coal power plants are operated at baseload and do not cycle on/off much. As these units age and are forced to operate in more flexible mode, the cost of cycling is likely to increase. This will result in slightly lower "baseload VOM" costs compared to historical results. These units cannot easily be brought online under these circumstances and such factors are not fully captured in this dataset. Note that there is a relatively small sample of supercritical coal units in WECC.
- Median cold start cost for each of the generation types is about 1 to 3 times the hot start capital and maintenance cost. For the lower bound 75th percentile, this ratio of cold start cost versus hot start cost is only slightly higher.
- Aeroderivative gas turbines and reciprocating gas engines are designed for flexible operation, and therefore have lower costs. These units also do not get heavily impacted in terms of reliability. In the case of gas turbines, the typical maintenance cycle of the units essentially renews the wear and tear damage. Note that fast starts are deviations to standard start sequence, which may result in increased cycling costs.
- There are some important economies of scale for large steam units that lower their per cycle costs. So, the highest costs per capacity, as shown here, occur in some less efficient or older smaller units, especially for cold starts.
- There is an inherent "tradeoff" relation between higher capital and maintenance expenditure and corresponding lower EFOR.
- Aging effects on conventional combined-cycle units is significant (in 2030). Older units act more like the present coal fleet, while the newer combined-cycle units tend to operate baseload or load following.

- Conventional (older) combined-cycle units were designed for baseload operation and when operated in cycling mode can have higher cycling costs. Similarly, the more efficient, higher temperature gas turbine-based combined-cycle units are also not designed for frequent start/stops. Hence, the cost per cycle of the high efficiency gas combined-cycle units is modestly higher than older combined-cycle units. The fast start combined-cycle units, as expected, are much more economical to operate in on/off mode.
- Reciprocating engines almost always operate as flexible units. The baseload VOM cost for these units is negligible as all the costs are cycling related. These units also do not see much effects on reliability from increased on/off cycles. At low load operation, typically engines on a site may be turned off.
- The coal-fired small and large units were the expensive load following units. As an example, the mill cycle from full load to low load adds significant costs. Emissions control equipment is also affected when units are operated at minimum load for extended hours.
- The combined-cycle units tend to have slightly lower but significant load following costs. This is true because the steam cycle components (i.e., the HRSG, ST, and balance of plant equipment) are impacted by changing operating transients at lower loads. The HRSG is the significant contributor to the cost, though some STs in the industry have been adversely affected by extended low load operation.
- Modest increases in ramp rates during load following results in almost no increase in damage or costs. Doubling accepted ramp rates (subject to design limit or original equipment manufacturer recommendation) is possible on the steam units, though such operation will increase costs. Yet, there might be market mechanisms that allow units to take advantage of the faster ramp rates.
- Aggregating cycling costs at the system level results in ignoring the "flash flood" situation of heavy cycling on individual units on the grid. Transmission expansion studies should include power plant cycling as an input.