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Impact of Load Following on the Economics of Existing Coal-Fired Power Plant Operations

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Executive Summary

Many policy and market issues are changing the nature of how and when various types of generators are dispatched. Whether it is due to a broader compliance effort directed at reducing CO₂ emissions from existing power generators, low natural gas prices, or part of a state renewable portfolio standard, coal generators will likely not continue the historically favorable dispatch position that they've held in the past, and they may be on the margin. This marginal operation will entail more frequent starts and stops, and a ramping up of operation to meet demand, which is expected to shorten the operating life of mechanical components and increase operation and maintenance (O&M) costs.

This report evaluates the effects of more frequent startups and shutdowns and load changes on O&M costs in existing, baseload, coal-fired power plants. Information available in the literature was leveraged using the experience of an international engineering, procurement and construction firm experienced in the design, operation, and maintenance of power plants.

An analysis, based on a discrete number of cold starts¹ per year, was conducted to determine the impact of starts, stops and load changes on a 300 MW coal-fired unit's O&M cost, and the resulting cost of electricity (COE). The impact on COE captures the increased costs associated with electricity generation (\$/MWh basis). For the purposes of this analysis, the capital cost of the existing unit is assumed to have been completely paid off, and is therefore no longer considered part of the COE calculation.

The scope of this report is limited to cold starts, which: (a) vary less in number across the existing fleet, and (b) have a more significant impact on plant equipment – per start – than either warm or hot starts. The latter is the result of the greater thermal cycling range of cold starts, from ambient to operating temperature. Warm and hot starts – while outside the scope of this analysis – may be significant for units in which the number of these starts outnumber cold starts, and will be investigated in the future.

The economic impacts of the repeated cold starts evaluated in this study are shown in Exhibit 1 and Exhibit 2. Exhibit 1 shows a typical merit-order dispatch curve for PJM in May 2015. A typical existing coal-fired unit (shown as the green square in Exhibit 1) has dispatch costs (which is the total of fuel and variable O&M) that are low enough for this particular unit to be economically competitive during periods of average load. This results in an annual capacity factor high enough for the unit to remain economically viable.

For the same unit experiencing monthly cold starts, dispatch costs rise to the point where the unit will only dispatch when the electric load approaches peak demand. This results in a decreased annual capacity factor and subsequent fall in revenue, making the unit less economically competitive.

¹Power plant startups are typically classified as hot, warm, or cold starts based on the length of time elapsed after shutdown, which directly relates to how much the process equipment has cooled down. While there are significant variations in the definitions of these terms, cold starts can be classified as when the boiler and steam turbine have sufficiently cooled down, reaching temperatures less than 250°F. Generally speaking, this occurs after the unit has been off-line for more than 48 hours.

Key Findings

Findings of this report focus on the changes to the O&M and fuel costs related to reducing generation through:

1. Decreasing the plant annual operating hours by increasing the number of plant shutdowns,
2. Operating the plant below its design capacity, at a lower load factor².

The results are primarily represented as increases with respect to O&M and fuel components of the COE. The increases are not expressed with respect to the total costs of electricity since the capital component of the existing unit under consideration is assumed to be fully paid off. The key findings of the report are as follows:

- The combination of startup fuel cost, periodic replacement and major maintenance costs, and annual routine maintenance and inspection cost of susceptible components (shown in Exhibit 3) could range from \$12,800/MW/year for 1 annual cold start to \$18,340/MW/year for 12 annual cold starts.
- Additional maintenance (in excess of the major maintenance costs noted above) for susceptible components and startup fuel costs could range from \$100/MW/Start to \$490/MW/Start depending on the number of annual cold starts between 1 and 12.
- On an annual basis, the routine maintenance and inspection costs for susceptible components can be as significant as the periodic replacement and maintenance costs.
- When the number of annual cold starts increases from 1 to 12, the susceptible components identified in Exhibit 3 require additional maintenance due to thermal cycling, and there are additional startup fuel costs. These additional costs are presented as an increase in COE. This component of COE can vary by 42% (from \$1.73/MWh to \$2.46/MWh)³ depending on the number of cold starts.
- About 20% of the fixed O&M cost contribution of the COE is related to the startup susceptible component maintenance cost and startup fuel cost.
- Increasing annual cold starts and stops from 1 to 6 (or 12) increases the total fixed costs⁴ by about 10%.
- Reducing capacity factor by decreasing load factor⁵ has a greater adverse impact on COE than by increasing the number of shutdowns (decreasing operating time).

² The capacity output level expressed as a percent of the full plant capacity. For example, 240MW plant operating at a load factor of 50% will have an output 120MW.

³ This analysis assumes 85% annual capacity factor

⁴ Fixed operating and maintenance are independent of the annual MWh's generated by a power plant.

⁵ Load factor is defined as the ratio of actual output to maximum rated output.

Exhibit 1 – PJM Dispatch Curve (May 2015)

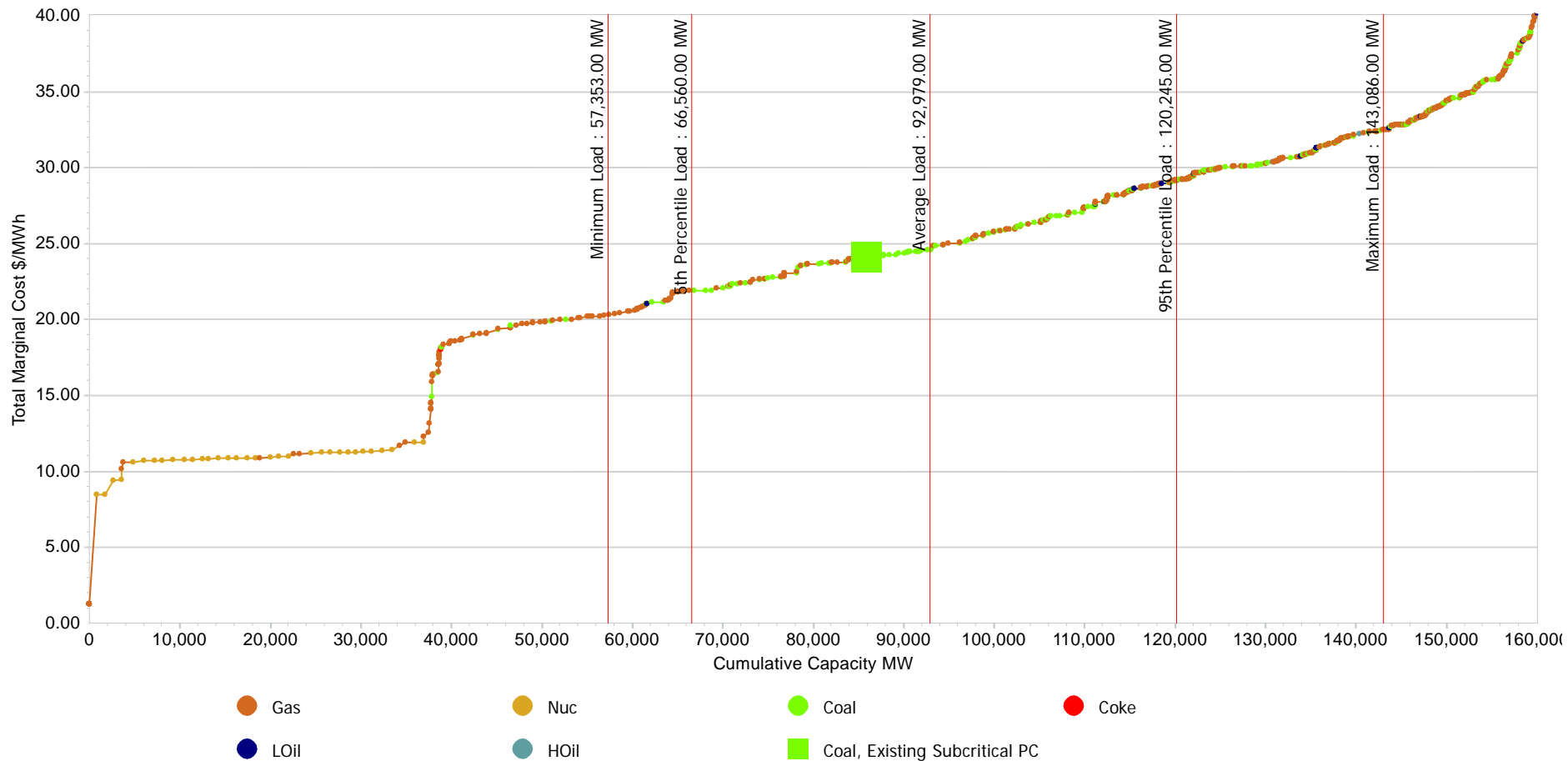
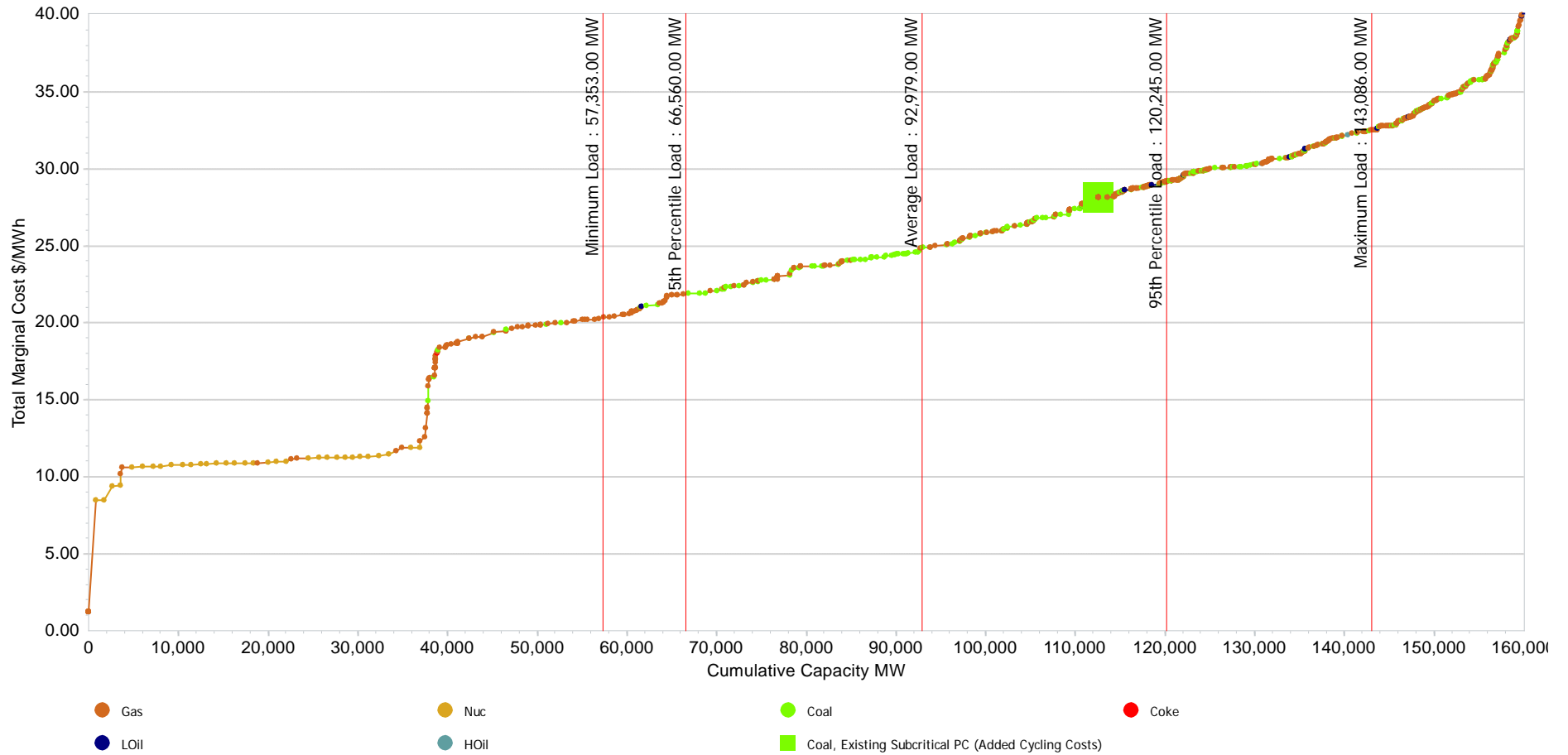


Exhibit 2 – PJM Dispatch Curve (May 2015) with Added Dispatch Costs due to Cycling



1 Introduction

It is anticipated that in the future, existing coal-fired electric generating units will be required to increase the number of plant shutdowns due to proposed environmental regulations, thereby increasing the cost of electricity. Coal generators have historically enjoyed early dispatch positions due to low fuel and operating and maintenance (O&M) costs, and therefore have not had to frequently ramp, or shut down, in the same way that is required of units on the margin. If coal-fired generators will be required to operate at a reduced capacity factor in the future, the impact of shutdowns versus operating at a decreased load factor needs to be evaluated by utilities to assess the most economically sound option.

This report evaluates the effects of more frequent startups and shutdowns and load changes on O&M costs in existing, baseload, coal-fired power plants and the resulting changes in the cost of electricity. O&M costs are typically divided between fixed and variable costs. The fixed O&M costs are independent of the generation from a plant and include administrative, operating and maintenance labor costs as well as property taxes and insurance. Variable operating costs are proportional to the plant generation and include items such as fuel, sorbent for sulfur removal, and other consumables. Since the COE is the O&M and fuel cost of the plant per megawatt hour of operation over the operation of the plant (30 years), the COE is dependent on the annual capacity factor, defined as the actual megawatt hours of operation divided by the maximum possible megawatt hours of operation. Load following, which involves running the plant at part load, will increase the plant heat rate which will increase the fuel cost (a variable cost) component of the COE.

A typical structure of the COE and contributing costs are:

- Capital (fixed)
- Operating and Maintenance
 - Fixed O&M
 - Annual operating labor
 - Maintenance labor including inspections
 - Administrative and support labor
 - Property taxes and insurance
 - Maintenance materials and some replacement equipment
 - Variable O&M
 - Fuel
 - Chemicals
 - Water

The capital costs and fixed O&M are independent of the plant generation. Variable operating costs are proportional to the plant generation. For this analysis, the assumption is made that the capital portion of the existing unit is completely paid off and is no longer considered part of the COE calculation.

The analysis presented in this report identifies:

- Which components in a power plant are most susceptible to early failure due to more frequent starts and stops;
- The impact on O&M costs associated with these operational changes;
- The increase in frequency and capital costs of major repairs and/or total replacement of the component;
- The effect of more frequent starts and stops on fuel costs;
- The effects that part load operation have on heat rate and fuel cost; and
- The impact of increased O&M costs and fuel costs on the cost of electricity.

Many policy and market issues are changing the nature of how and when various types of generators are dispatched. These market issues included emissions regulations such as Mercury and Air Toxics Standards (MATS) and Cross-State Air Pollution Rule (CSAPR), natural gas prices and greater contributions to the grid from renewables. Whether it is due to a broader compliance effort directed at reducing CO₂ emissions from existing power generators, low natural gas prices, or part of a state renewable portfolio standard, coal generators will likely not continue the historically favorable dispatch position that they've held in the past. This shift in operation will entail more frequent shutdowns, and a ramping up of operation to meet demand.

Operations to accommodate frequent load changes or shut downs are expected to shorten the life of mechanical components (such as pumps, compressors, fans, etc.). This will increase O&M costs by requiring more frequent mechanical component replacement, compared to historic coal-fired electric generating unit operation.

Since existing coal units will now be closer to the margin, revenues will decrease because these units will not operate as many hours per year. This may be a result of a renewable portfolio standard or because lower-emitting fuel sources (such as gas or renewables) receive preferential dispatch.

An analysis, based on a discrete number of cold starts per year, was employed to determine the impact of more frequent starts and stops on a 300 MW coal-fired unit's O&M cost and COE. The scope of this report is limited to cold starts, which: (a) vary less in number across the existing fleet, and (b) have a more significant impact on plant equipment – per start – than either warm or hot starts. The latter is the result of the greater thermal cycling range of cold starts, from ambient to operating temperature. [1] One, six, and twelve cold starts per year were evaluated, with one start chosen as the reference case since it is representative of the annual outage scheduled by baseload plants⁶. A maximum of 12 cold starts was considered based on the time required for a unit to cool down and then be restarted. Approximately 7 days is required for a cold start of a coal-fired power plant, from initial boiler heating to full load operation. Warm and hot starts – while outside the scope of this analysis – may be significant for units in which the number of these starts outnumber cold starts, and will be investigated in the future.

⁶ Analysis of data from the Ventyx Velocity database for the ERCOT region (an area with high renewable penetration) indicates there are an average of 3.5 cold starts per year for all coal-fired plants over the past 13 years. The highest number of reported annual cold starts for a single unit was 13 with 23 out of 32 units reporting at least 1 year with 1 cold start.

2 Impacts of More Frequent Ramping and Starts/Stops on Mechanical Components

Generally, an increase in frequency in ramping and/or shutdowns decreases the component life through damage caused by creep, fatigue, thermal shock, acid-induced corrosion, erosion, and other stresses. The degree to which cycling-induced damage will affect a specific plant and its operation is not understood very well because it depends on the size, age, and design characteristics, as well as the level of cycling the plant will undergo.

This report focuses on those major components that, according to literature sources, tend to exhibit more susceptibility to early failure due to frequent ramping and/or increased cycling. Exhibit 3 shows the components that are included in the analysis and the most recurrent maintenance issue(s) encountered when subjected to frequent ramping and/or starts and stops. For purposes of this report, these components are referred to as “susceptible components.”

The susceptible components referenced in this report are for a baseload, subcritical, pulverized coal power plant. Subcritical pulverized coal power plants were selected for this report based on the larger number of subcritical units and greater capacity of subcritical power plants (66% of total installed coal capacity) compared to supercritical power plants in the United States.⁷

Exhibit 3: Susceptible Components and Related Maintenance Issue List

Component	Maintenance Issue	Source
Coal Pulverizer	Prone to fireside explosions especially with Western Coals. Mechanical wear when cycled at low end of minimum flow rates.	2
Boiler/Steam Drum	Fatigue caused primarily by the temperature differential between sub-cooled inlet feedwater and saturation temperature of steam-water mixture.	3
Boiler Refractory	Cracking and erosion from low load operations.	1
Superheater Header & Tubes	Overheating from low/no-flow of cooling steam (startup) and/or poor combustion gas temperature management causes thermal deformation. Internal ligament cracking. Oxidation and exfoliation from exposing metal to higher temperatures than design.	3
Reheater Tubes	Fatigue caused by high temperature differential and hot spots from low steam flows during startup. Load cycling causes overheating failures in the long-term. Resulting tube exfoliation may damage IP turbines.	4
Economizer Tubes	Thermal shocking damage due to relatively cold water during startup. Corrosion may occur if cold water lowers metal temperature below acid dew point of flue gas during low load.	3

⁷ From the Ventyx Velocity database:
 Supercritical - 129 units with a total of 86,416 MW operating capacity
 Subcritical - 912 units with a total of 167,842 MW operating capacity

Component	Maintenance Issue	Source
Lower Furnace Tubes	Fatigue failures resulting in tube leaks increases with increasing number of starts. Increased erosion at low loads.	2, 3
Windbox Supports	Structural damage caused by large transient temperature differences.	2
Feedwater Heaters	Early tube failures due to cool-down and rapid heating during hot/warm startup cycle. Tube grooving at the support plates can occur due to poor water chemistry.	2
Boiler Feed Pumps	Accelerated wear at low load operation for units that do not have variable frequency drives or hydraulic couplings.	3
Steam Turbine/Generator	Steam seals may need to be replaced to prevent steam from bypassing rotor stages. Most units have been changed to Brandon packing; primary concern would be exhaust hood temperatures and ability to control the temperature at low steam flows.	3
Admission Valves	Throttling increases wear and reduces efficiency.	2
Turbine Rotor	Reducing startup time and increasing the number of annual start cycles can substantially enhance rotor material degradation, causing rotor failure. This may result in blade loss, spindle fracture, and even fast fracture from a near-bore causing catastrophic failure.	2
LP Turbine Blades	Solid particle erosion. Impingement of droplets leads to accelerated damage of erosion shields and blade surfaces. LP last stage blade stall flutter at low flow conditions may cause blade vibration, resulting in cycle fatigue.	2
Generator	Retaining ring and end-turn fatigue that can lead to failure/arcng. This will only be an issue if they require a shift from the generator to line voltage of $\pm 20\%$.	2
Steam Piping	Thermal stress and fatigue cracking due to temperature fluctuations.	2
FGD Absorber	Thermal stress and fatigue cracking due to temperature fluctuations.	3
FGD Pumps and Motors	Additional rotational loads on motors and pumps as they are accelerated to operating speed.	3
Baghouse	Wet gas corrosion from operating below acid dew point at low load.	2
FD/ID Fans	Frequent start/stop of fans increases failure rates, inspection intervals, and motor-fan maintenance.	3
Dampers	Load following & partial load require more oscillation of dampers, increasing wear.	2
Air Heaters	Wet gas corrosion from operating below acid dew point at low load.	3

Component	Maintenance Issue	Source
Pump Motors	More wear on oscillation valves and motor due to oscillation of control valves. VFDs could prolong life of motor and control valves and reduce energy load.	2
Condenser	Tube grooving at support plates can occur due to poor water chemistry.	2

3 Impacts of Cold Starts on O&M Frequency and Cost

This section assesses the impact of cycling on the operating and maintenance frequency cost for the susceptible components identified in Exhibit 3. Cost data from various sources was normalized to the 300 MW subcritical coal-fired unit size, and were adjusted for inflation to mid-2013 U.S. dollars.

Depending on the susceptible component selected, cycling-induced damage may:

- Vary the frequency at which planned or unplanned major repairs (or equipment replacement) are required,
- Increase the total expected costs associated with a given major repair or replacement (e.g. more boiler tubes need replacement, larger area to re-line in absorber, etc.),
- Increase the annual routine maintenance and inspection costs.

3.1 Impact on Frequency of Equipment Repair/Replacement

An analysis is used to evaluate the impact of cycling on the frequency at which major repair or total replacement of a susceptible component takes place. The scope of this report is limited to cold starts, which are expected to have a more significant impact on plant equipment – per start – than either warm or hot starts. [1] For this reason, the analysis on each susceptible component was centered on 1, 6, and 12 cold starts per year. One cold start per year was selected as the reference case because it represents the annual outage scheduled by baseload plants.

Exhibit 4 shows the expected replacement frequency of susceptible components, as well as cost implications (replacement/major repair, and annual routine inspection) as functions of the number of annual cold starts. The data are from WorleyParsons’ experience in the construction and maintenance of coal-fired power plants. Most of the susceptible components show a range in the frequency at which a replacement or major repair takes place. This range represents the variability that exists for each component due to specific plant maintenance philosophy, manufacturer’s recommendation, redundancy, and financial considerations, among others. There is a significant amount of overlap between the ranges and, in some cases, apparently small changes in the time between replacement/major repairs as the number of cold starts increase.

Exhibit 4 Impact of More Frequent Starts/Stops on Component Replacement/Major Repair Frequency and Maintenance Costs

Component	Time Between Replacement/Major Repair (Years)			Replacement/Major Repair Cost (1000\$/MW)	Annual (Routine) Maintenance and Inspection Cost (1000\$/MW/year)		
	1 Start	6 Starts	12 Starts		1 Start	6 Starts	12 Starts
Coal Pulverizer	6	5	4	1.33	0.92	1.0	1.0
Steam Drum	Annual maint. only	Annual maint. only	Annual maint. only	N/A	1.8	2.2	2.2
Boiler Refractory	Annual maint. only	Annual maint. only	Annual maint. only	N/A	1.0	1.5	1.5
Superheater/Headers/Tubes	10	9-10	8-10	8-30.6	0.067	0.080	0.080
Reheater Tubes	10	9-10	8-10	10-23.3	0.067	0.080	0.080
Economizer Tubes	9	8-9	7-8	5.0-10.0	0.067	0.080	0.080
Lower Furnace Tubes	8-10	7-9	6-8	0.15-1.05	0.067	0.080	0.080
Windbox Supports	8-10	7-9	6-8	0.33-0.50	0.067	0.080	0.080
Feedwater Heaters	15-20	18	15	0.67-4.33	0.25	0.25	0.25
Boiler Feed Pumps	8-10	7-9	6-8	0.50	0.25	0.30	0.30
Steam Turbine Generator (STG)					0.030	0.030	0.030
Minor Overhaul	2-4	2-3	2-3	0.53	N/A	N/A	N/A
Major Overhaul	5-10	5-8	5-8	10	N/A	N/A	N/A
Admission Valves	2-4	2-3	2-3	Incl. in minor overhaul cost	Incl. in STG cost	Incl. in STG cost	Incl. in STG cost
Turbine Rotor	5-10	5-8	5-8	Incl. in major overhaul cost	Incl. in STG cost	Incl. in STG cost	Incl. in STG cost
LP Turbine Blades	5-10	5-8	5-8	Incl. in major overhaul cost	Incl. in STG cost	Incl. in STG cost	Incl. in STG cost

Component	Time Between Replacement/Major Repair (Years)			Replacement/Major Repair Cost (1000\$/MW)	Annual (Routine) Maintenance and Inspection Cost (1000\$/MW/year)		
	5-10	5-8	5-8		Incl. in STG cost	Incl. in STG cost	Incl. in STG cost
Generator	5-10	5-8	5-8	Incl. in major overhaul cost	Incl. in STG cost	Incl. in STG cost	Incl. in STG cost
Steam Piping	25 year life			63.3	0.067	0.080	0.080
FGD Absorber	15	14-15	13-15	3.11-6.23	0.031-0.062	0.044-0.087	0.056-0.11
FGD Pumps & Motors	8-10	7-9	6-8	0.30	0.25	0.30	0.30
Baghouse	5	4-5	3-5	2.38	0.48	0.56	0.58
FD/ID Fans	5	4-5	4	0.57	0.077	0.077	0.077
Dampers	5	4-5	4	0.40	Incl. w/ fans	Incl. w/ fans	Incl. w/ fans
Air Heaters	10	9-10	8-10	5.67	0.63	0.82	0.82
Pump Motors	8-10	7-9	6-8	0.12	0.50	0.60	0.60
Condenser	5	5	5	2.00	0.180	0.182	0.182

Note: All costs are in mid-2013 dollars

For most susceptible components, in particular the boiler components, there is a direct correlation between the number of cold starts and the frequency of major repairs or replacement. This will have an impact on the O&M costs throughout the life of the plant. For example, over a 30 year plant life, the coal pulverizer is expected to undergo 5 major repairs if operated with 1 cold start per year, but this number increases to 6 and 7 major repairs if the unit shut downs every other month (6 cold starts) or monthly (12 cold starts) on average.

Other susceptible components, such as the steam turbine generator, exhibit a similar general trend, but the frequency of the minor and major overhauls is affected more by scheduling factors than by the cycling-induced damage that they may sustain. Steam turbine minor overhauls consist primarily of valve work, equipment calibration, and general inspection. Major overhauls include minor overhaul tasks, opening of the turbine casing, examination of blading and stator core, and dismantling the generator rotor. Major overhauls are very labor and capital intensive, and so periodic maintenance is based on the number of operating hours and the plant's assessment of the remaining life of the rotor. As such, the frequency range for minor and major overhauls remains unaltered for 6 and 12 cold starts.

The condenser major repair frequency is expected to remain the same irrespective of the number of cold starts since condenser re-tubing requires opening the condenser casing, which is extremely labor intensive. In this case, the nature of the repair sets the scheduling frequency for maintenance.

The boiler refractory periodic maintenance is listed as "annual maint. only" (annual maintenance only), since the refractory is normally repaired annually, and thus the costs incurred are listed under the annual (routine) maintenance and inspection costs shown in Exhibit 4. Similarly, the boiler steam drum does not have a total replacement cost or period since it is not economically feasible to replace this component. Costs associated with annual repairs and inspections are included under the annual routine maintenance cost in Exhibit 4.

In the case of steam piping, no plant data were available for the frequency of periodic major repair, so the initial total installed cost for steam piping over a 25- year life was utilized in the cost analysis [5].

3.2 Impact on Periodic Replacement/Major Repair Cost

The estimated total installed costs, expressed in thousands of dollars per megawatt, for the susceptible components are also listed in Exhibit 4. These costs either represent a major repair or a total component replacement cost. Typically, these costs represent periodic major maintenance, with the exception of some boiler components (superheater, reheater, and economizer) and the steam piping. All cost data presented has been scaled to a 300 MWe plant size and adjusted to mid-2013 U.S. dollars.

The replacement and major maintenance costs are sometimes given as a range due to the variations in component design, task complexity, differing scope of work, labor costs, and/or materials of construction.

The different steam turbine components have been grouped into the minor and major overhaul costs as indicated in Section 2.

The frequency of maintenance and replacement of susceptible components is a function of the number of annual starts and stops. In reality, a susceptible component may be scheduled for service at regular intervals but at a higher repair/replacement cost due to increased damage from a more intensive mode of operation (increased starts and stops). The latter approach, though perhaps more realistic for a given power plant, would require historical operational data to establish a working baseline in order to differentiate the impact of cycling from regular wear and tear, human error, plant modifications, market price fluctuations, and other factors.

3.3 Impact on Routine Annual Maintenance and Inspection Cost

Exhibit 4 shows the estimated total routine maintenance and inspection costs for the susceptible components for a given number of cold starts. These routine costs include those maintenance items that are performed regularly every year (e.g. bearing replacement, lubrication tasks, tube leak repairs, valve replacement, etc.), including detailed component inspections, non-destructive evaluations, instrument recalibration, and others. In most cases, labor costs, including contractor labor, account for the majority of the cost listed.

Most susceptible components show an increase in the annual routine maintenance costs when the number of cold starts is increased from 1 to 6 or 12. These higher routine costs are explained by having more frequent inspections for a given component to monitor the cycling-induced damage. Often, the routine maintenance cost does not vary from 6 to 12 cold starts because the inspections are scheduled and the damage induced by the number of starts and stops is gradual.

The superheater, reheater, economizer, lower furnace tubes, windbox supports, and steam piping show the same annual routine maintenance cost because it includes the cost of inspections and non-destructive evaluations. Increasing the number of starts/stops from the reference case elevates these costs by an estimated 20%.

The susceptible components associated with the STG are serviced and examined during minor or major overhauls. The annual routine maintenance cost listed under STG corresponds to overspeed tests and visual inspections of the different components (e.g. gearbox, seals, bearings, instrumentation, etc.) for leaks, wear, filter plugging, and vibration damage.

The routine maintenance costs for FD/ID fans remain constant because they represent the annual detailed inspection, changes of oil filters, and checking of the oil condition. The routine maintenance costs also include any necessary inspection of the dampers.

4 Impacts of Starts and Stops on Annual Startup Fuel and O&M Costs

Startup Fuel Costs

With every cold start there is a cost for startup fuel to heat the unit. In addition, there is an impact on the unit's heat rate after a hot, warm, or cold start. In Intertek APTECH's 2012 "Power Plant Cycling Costs" report, this percent increase in effective weekly heat rate is given as 0.44 percent for large (300 – 900 MW), subcritical coal units; irrespective

of the type of start. [4] For the purposes of this report, “startup fuel costs” include the fuel cost to heat the unit and the additional coal burned during the first week due to a 0.44 percent increase in heat rate.

Susceptible Components’ O&M costs

For each susceptible component, the major repair or replacement costs were multiplied by the number of instances it has to be repaired or replaced over a 30-year operational period, for each given number of cold starts. These costs are then normalized on a first-year basis. Any residual repair/replacement cost left in the component at the 30th year is credited evenly over the entire operation period. The total annual O&M costs for the susceptible components considered in this report are the summation of the annualized periodic major repair/replacement, the routine maintenance, and the startup fuel costs. This total cost is then divided by 300 MW to express them in dollars per megawatts, per year.

Since the time between periodic maintenance was estimated and presented in Exhibit 4 as a range of years in most cases, the total O&M cost is presented in this report for both the minimum estimated repair/replacement frequency (less frequent component replacement/repair, as shown in Exhibit 4) and the maximum repair/replacement frequency (more frequent component replacement/repair, as shown in Exhibit 4) for a given number of cold starts.

Exhibit 5 lists the assumptions utilized in this report to develop the cost estimation analysis. These assumptions were used to develop total annual costs (on a capacity basis, in units of \$/MW/year) and cost of electricity (\$/MWh). These costs are typically broken down by capital (loan repayment), fixed O&M, variable O&M, and fuel costs. Capital and fixed O&M are considered to be fixed costs (independent of the number of annual megawatt hours generated). The fuel and variable O&M costs are considered to be variable costs and their total annual costs are proportional to the annual number of megawatt hours generated.

Exhibit 5: General Report Basis

No.	General Report Basis	
1	Plant Operation	30 years
2	Boiler Fuel	Illinois No. 6 Coal
3	Fuel Cost	\$2.35/MBtu
4	Total Plant Fixed Costs (including susceptible components) ⁵	\$73,623/MW/yr
5	Non-fuel variable operating costs ⁵	\$8.47/MWh
6	Nominal Heat Rate for 300 MW Plant at Full Load	10,000 Btu/kWh
7	Nominal Annual Capacity Factor for Baseload Plant	85%
8	Capital Costs	None (existing unit assumed to be fully depreciated)
9	Cost of Electricity	\$41.86/MWh

4.1 Annual Startup Fuel Costs and Susceptible Components' O&M Costs

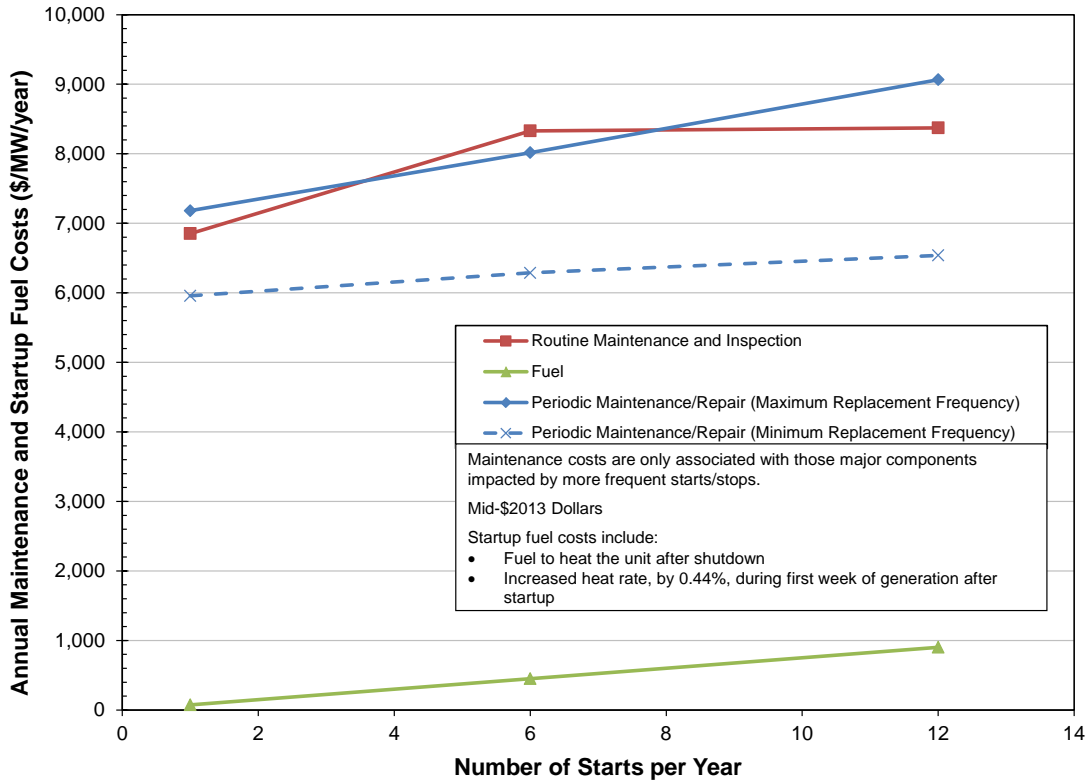
The startup fuel costs and susceptible components' O&M costs can be considered and compared in a variety of ways as illustrated in Exhibit 6 to Exhibit 8:

1. Exhibit 6 shows the magnitude of these cost accounts (routine maintenance, periodic maintenance and startup fuel) as a function of the number of cold starts per year for both the minimum and maximum replacement frequency shown in Exhibit 4.
2. Exhibit 7 contains the same cost accounts shown in Exhibit 6, but expresses them as total annual costs, as a function of the number of starts per year for both the minimum and maximum replacement frequency shown in Exhibit 4.
3. Exhibit 8 contains the same cost accounts shown in Exhibit 6 and Exhibit 7, but expresses them as a cost per start for both the minimum and maximum replacement frequency shown in Exhibit 4.

The exhibits in this report labeled "Min Freq" are associated with the minimum replacement/repair frequency for components in Exhibit 4 (less frequent component replacement/repair), and the data labeled "Max Freq" are associated with the maximum replacement/repair frequency (more frequent component replacement/repair). In Exhibit 7, the routine maintenance costs are similar for 6 and 12 cold starts because the increase in costs from the reference year (1 cold start) are due to additional scheduled inspections, which remain constant at the higher number of cold starts. Therefore, the inspection costs do not increase with increasing cold starts beyond 6 per year. Further, the annual routine maintenance and inspection costs for susceptible components are essentially equal to the periodic major repair/replacement cost at the higher end of the replacement frequency range.

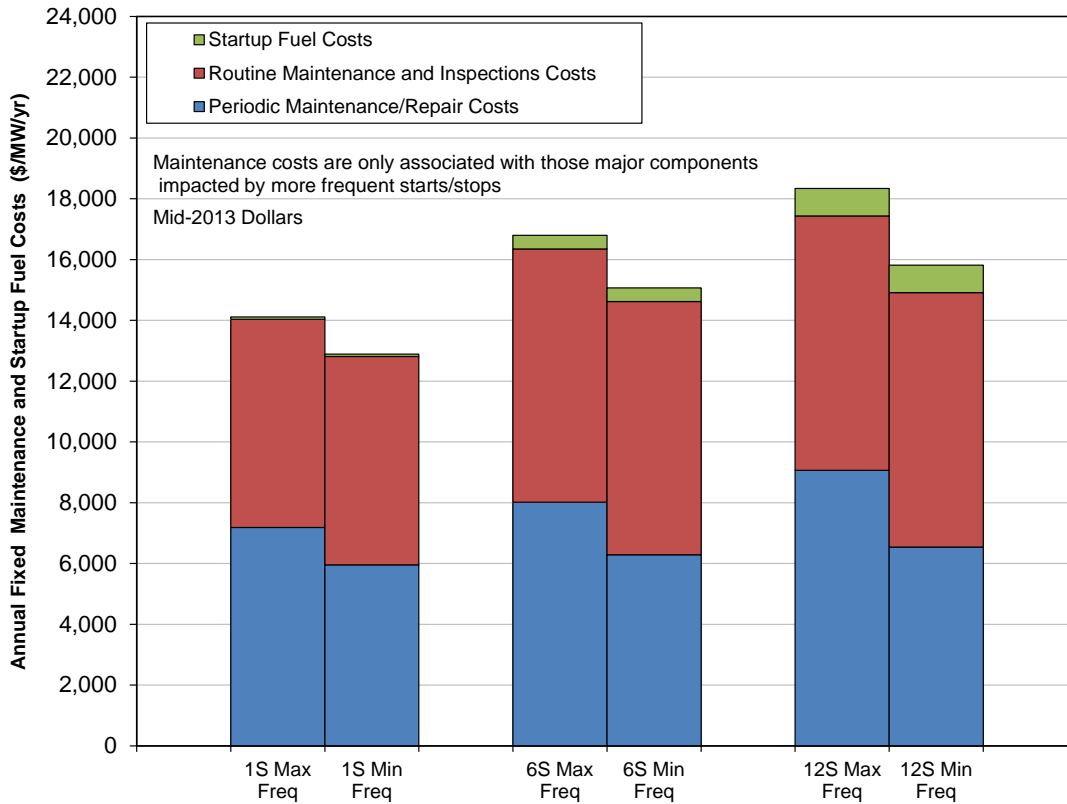
The startup fuel costs are less than 10% of either the routine or periodic maintenance costs. Therefore, the startup fuel costs do not contribute significantly to the annual costs associated with increasing the number of unit starts and stops.

Exhibit 6: Routine/Periodic Maintenance and Startup Fuel Costs as Functions of Cold Start Frequency



The total annual periodic replacement/major maintenance and routine costs for susceptible components and startup fuel costs, on a per megawatt basis, are shown in Exhibit 7. This figure combines the individual costs at each number of starts per year presented in Exhibit 6. Based on the data, this combined cost could range from \$12,800/MW/year for 1 annual cold start to \$18,340/MW/year for 12 annual cold starts, a 43% cost increase. The total costs in Exhibit 7 represent approximately 20% of the typical annual fixed O&M costs.

Exhibit 7 Total Annual Maintenance and Startup Fuel Costs as Functions of Cold Start Frequency



The cost per cold start per megawatt can be derived from the information presented in Exhibit 6. The development of this metric provides information about:

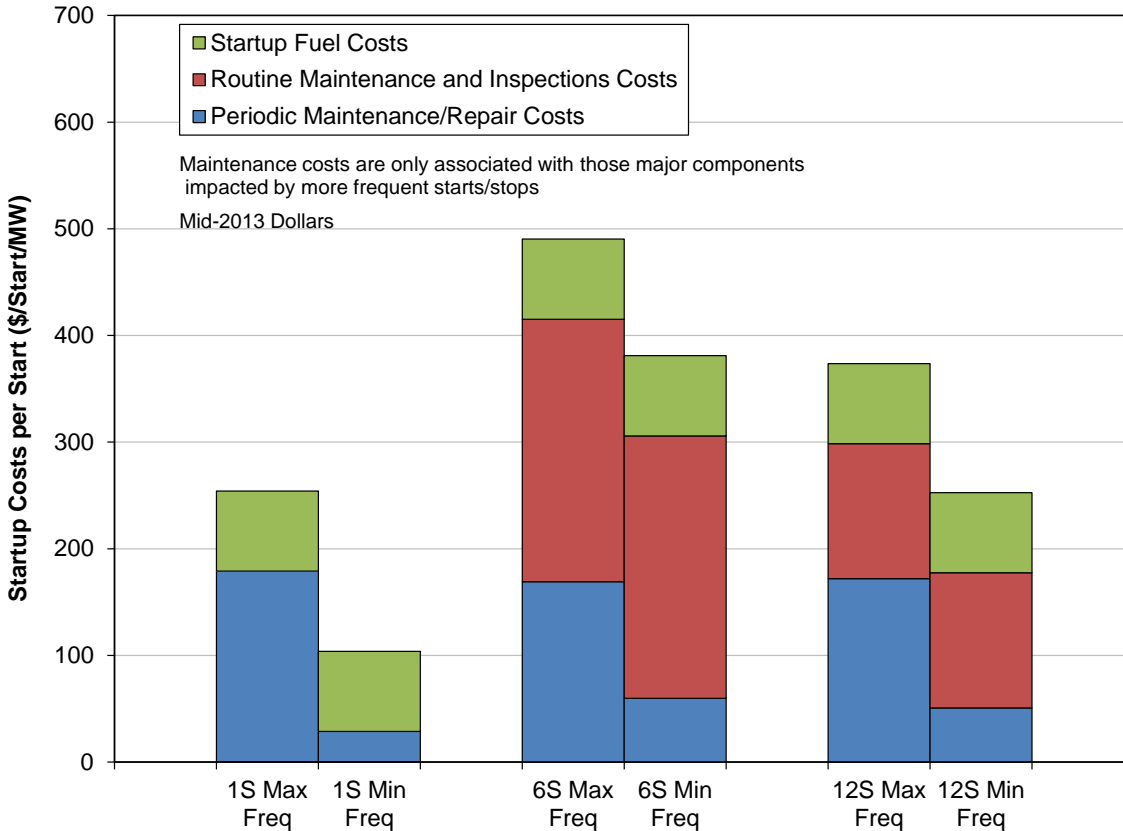
1. If and how the cost per start changes with the number of starts per year
2. The factors that contribute to a change in cost per start.

The cost contributions per start from the three factors considered in this study (startup fuel, routine maintenance and inspection, and periodic maintenance/repair) can be found from the slopes of the lines between the points in Exhibit 6. In Exhibit 8, it is assumed that the cost for one annual cold start is the same as if there were no cold starts (i.e. the unit is online all year round). Hence, the bar charts representing the minimum and maximum cost per start for one cold start do not include a routine maintenance and inspection cost component, because one annual cold start is assumed to be typical operation.

Exhibit 8 indicates that the maintenance and startup fuel costs for susceptible components could range from \$100/MW/start to \$490/MW/start depending on the number of cold starts between 1 and 12. The cost per start range is consistent with estimates reported by APTECH in their 2012 report, which ranged from \$63/MW/start to \$286/MW/start, when considering that the APTECH estimates were reported to be lower bound costs. [4]

From 1 to 6 starts, there can be as large as a 390% increase in the cost per start, while from 1 to 12 starts, there can be as large as a 275% increase in the costs per start. This cost per start decrease from 6 cold starts to 12 cold starts per year is primarily due to the fact that the routine maintenance and inspection cost is similar for 6 and 12 cold starts.

Exhibit 8 Annual Maintenance Cost Annual Startup Fuel Costs per MW per Start

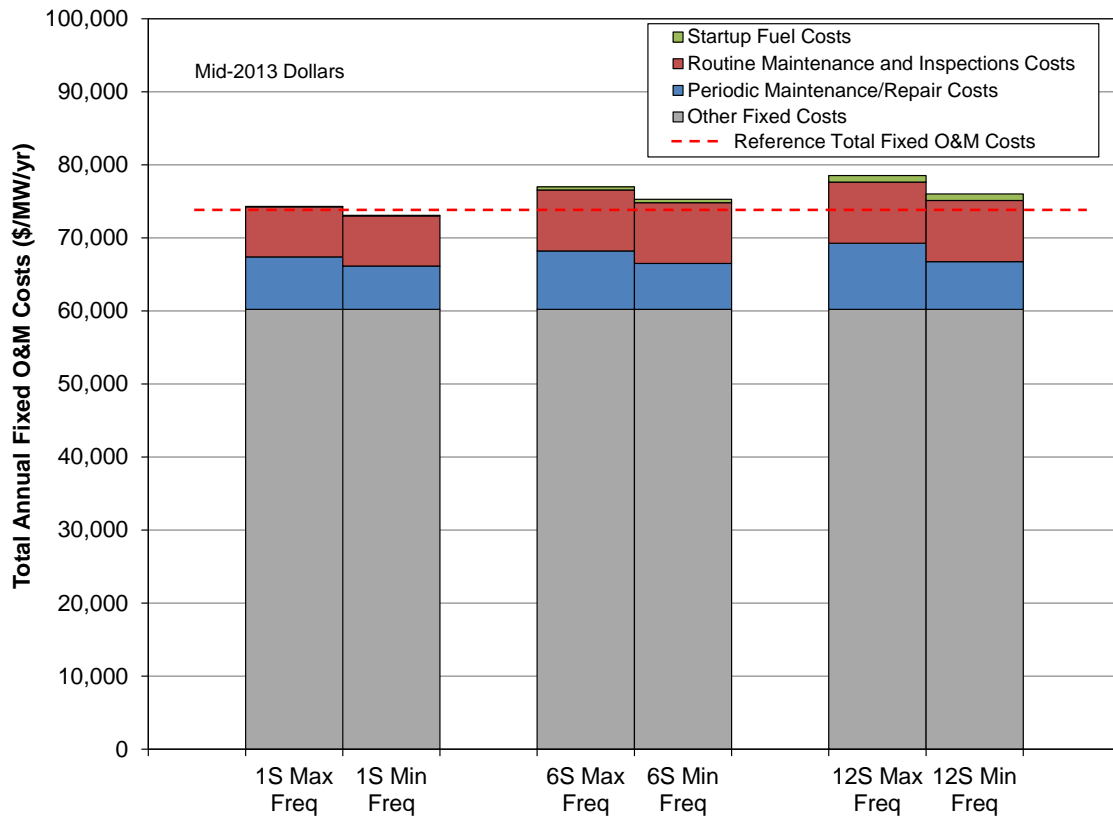


4.2 Total Fixed O&M Costs and Annual Startup Fuel Costs

Exhibit 9 shows the estimated total annual fixed costs per megawatt. Besides the O&M and startup fuel costs for the susceptible components, this chart includes the plant “Other Fixed Costs”; that is, those costs associated with plant O&M that are not impacted by starts/stops.

These “Other Fixed Costs” shown in Exhibit 9 are those costs that are not impacted by unit shutdown frequency. These costs are obtained by subtracting the periodic/routine maintenance and startup fuel costs from the baseline (one annual shutdown) plant’s Total Fixed Operating Cost. [2] The annual periodic and routine maintenance costs for the susceptible components and startup fuel costs represent about 20 percent of the Total Fixed Operating cost. Further, increasing the number of cold starts/stops from 1 to 12 per year increases the Total Fixed Operating Cost by about 10%.

Exhibit 9 Total Annual Fixed O&M and Startup Fuel Costs



5 Impacts of Starts/Stops on Cost of Electricity (COE) and CO₂ Emissions

The following sections analyze the impact of more frequent starts and stops on the COE as a function of a plant's capacity factor and load factors. A typical structure of the COE and contributing costs are:

- Capital (fixed)
- Operating and Maintenance
 - Fixed O&M
 - Annual operating labor
 - **Maintenance labor including inspections (included in this analysis)**
 - Administrative and support labor
 - Property taxes and insurance
 - **Maintenance materials and some replacement equipment (included in this analysis)**
 - **Startup fuel costs (included in this analysis)**
 - Variable O&M
 - Fuel
 - Chemicals
 - Water

For these analyses, the assumption is made that the capital costs are completely paid off and are no longer considered part of the COE calculation. In this case, the only remaining costs are the O&M and fuel costs. Components of particular interest to the impact of cold starts are bolded in the above list.

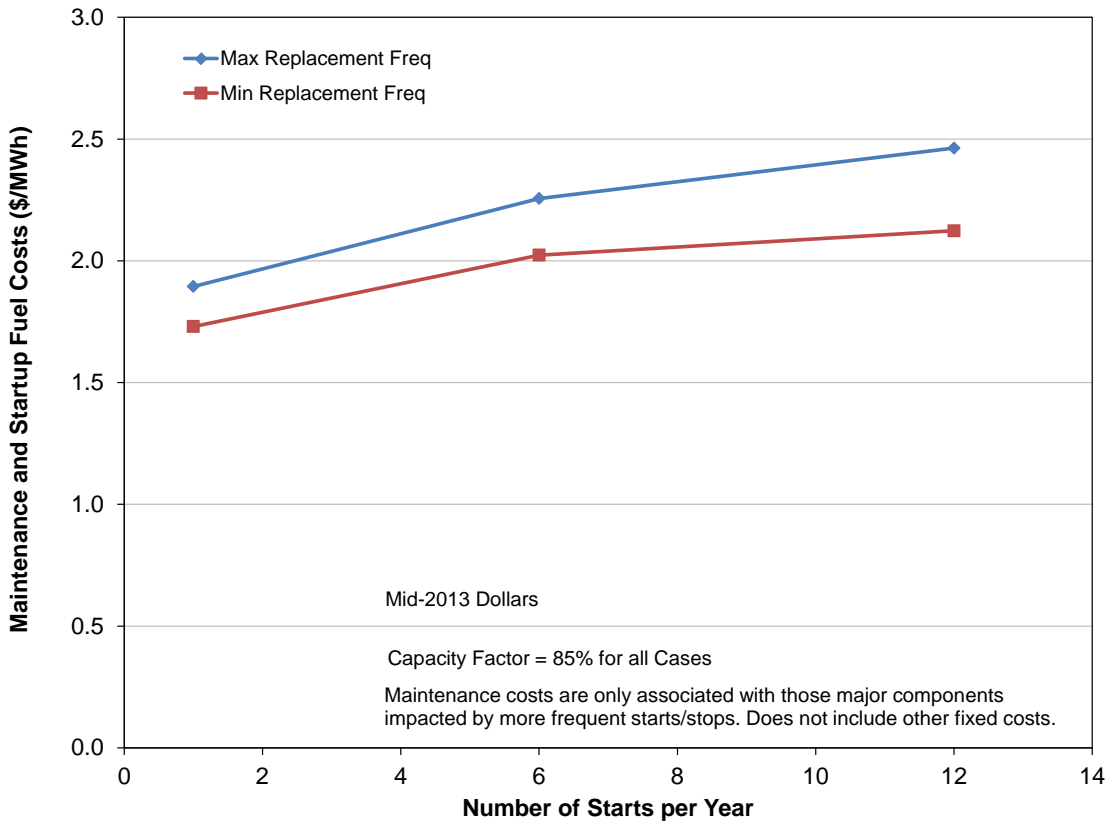
The annual capacity factor, the ratio of a plant's annual generation to the plant's generation if it runs at 100 percent capacity for one year, can be varied by either reducing the plant's number of operating hours, operating at a reduced power output (lower load factor), or a combination of both. The load factor is defined as the ratio of the plant's actual power output to the design full load power output. The COE is also impacted by the load factor in that the heat rate for a pulverized coal-fired power plant (and therefore the fuel cost) varies with load factor.

In addition, the reduced operation expected for existing coal-fired power generators will result in a decrease in their annual CO₂ emissions.

5.1 Susceptible Components' O&M Costs Impact on COE

The COE contribution from the susceptible components' O&M costs (periodic maintenance/repairs, routine maintenance and inspections, and startup fuel costs) can be determined by dividing the annual fixed costs, shown in Exhibit 7, by the annual generation. The result is the contribution of the increased susceptible components' O&M costs to the COE with varying number of annual cold starts on a \$/MWh basis, shown in Exhibit 6. These data assume an annual plant capacity factor of 85% irrespective of the number of cold starts, and a load factor of 1 (the unit runs at full load when online). Depending on the frequency of the periodic maintenance, the contribution to the COE from the susceptible components can range from \$1.73/MWh to \$2.46/MWh, 18% to 23% of the fixed operating cost. The curves shown in Exhibit 10 are the same costs in Exhibit 6, expressed on a \$/MWh basis. Exhibit 10 exemplifies a theoretical scenario (fixed capacity and load factors at baseload operation levels) but provides insight into the additional COE costs incurred from more frequent starts and stops.

Exhibit 10 Routine and Periodic Maintenance Costs of Susceptible Components and Startup Fuel Costs

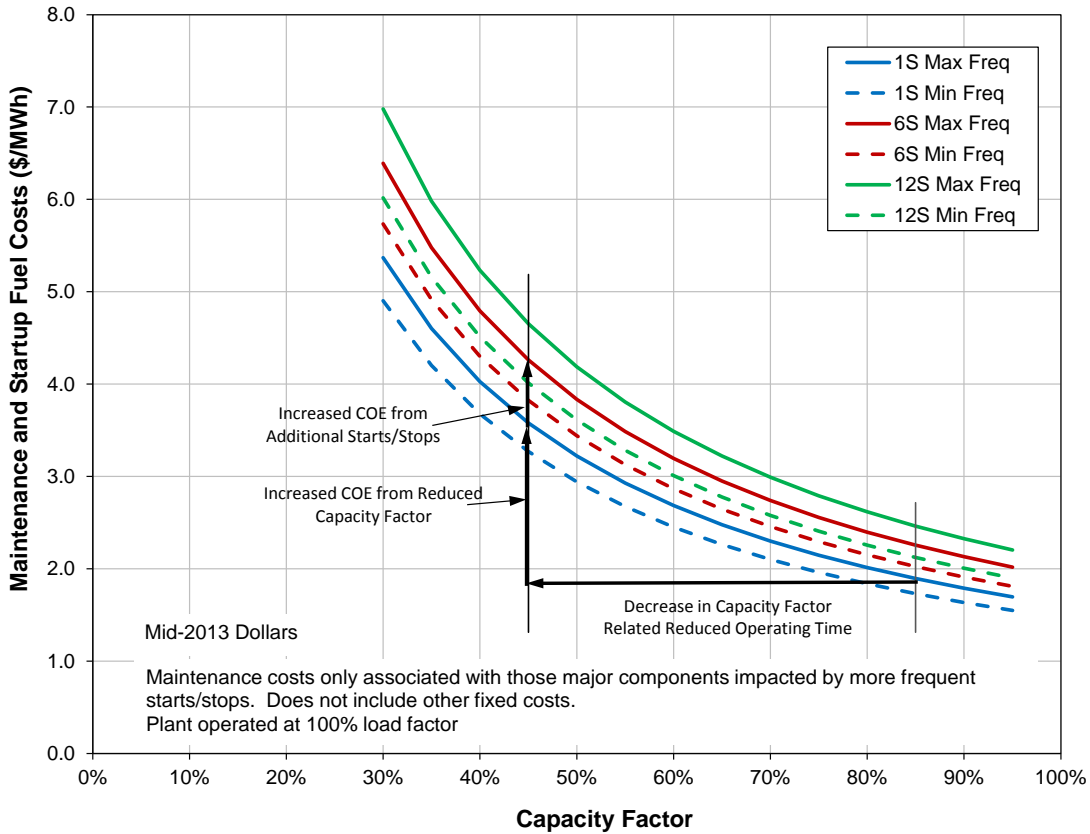


5.2 Impact of Decreasing Capacity Factor by Increasing Downtime

Exhibit 11 considers only the susceptible components' O&M and startup fuel costs, and evaluates how that portion of the COE changes as a function of cold starts and stops, thereby resulting in a change in annual operating hours. . The costs presented in Exhibit 11 also vary as functions of the number of cold starts (1, 6, or 12), and maintenance frequency.

Exhibit 11 also shows that the susceptible components' O&M and startup fuel costs increase as the number of starts/stops per year increases for all capacity factors. This increase is observed by the curves shifting upwards with increasing cold starts. For example, the susceptible components and startup fuel costs at 85 percent capacity factor, for 1 cold start per year (maximum frequency curve), is \$1.89/MWh. If the capacity factor is reduced to 45 percent (3,942 hours per year) by shutting the unit down once a year, the COE contribution becomes \$3.58/MWh, almost a 90 percent increase. However, if the number of cold starts is increased to 6 per year for the same 45 percent capacity factor, the COE contribution increases to \$4.26/MWh, an additional 19 percent over the 1 cold start case.

Exhibit 11 Maintenance and Startup Costs as a Function of Capacity Factor for a Range of Annual Starts and Stops



5.3 Impact of Decreased Load Factor on Heat Rate and Fuel Costs

As stated before, the capacity factor can also be reduced by running the unit at partial capacity; that is, at a lower load factor. A reduction in load factor increases the unit’s heat rate, which will increase the fuel costs, thus increasing the COE.

Exhibit 12 illustrates the heat rate change as the load factor is reduced. In this exhibit, the nominal heat rate at 100 percent load factor is assumed to be 10,000 Btu/kWh. The range of values at a given load factor is provided to illustrate the variation related to the plant configuration including the condenser pressure and plant condition or age.

As shown, operating at a load factors as high as 55 to 60 percent can result in a 5 percent increase in heat rate (from 10,000 to 10,500 Btu/kWh) while operating at lower load factors – 33 to 42 percent – can result in a 10 percent increase in heat rate. It is common for coal-fired generators to have minimum operating load factors of 30 or 40 percent, although some utilities are retrofitting their plants to go even lower.

Exhibit 12 Change in Heat Rate as a Function of Load Factor⁸

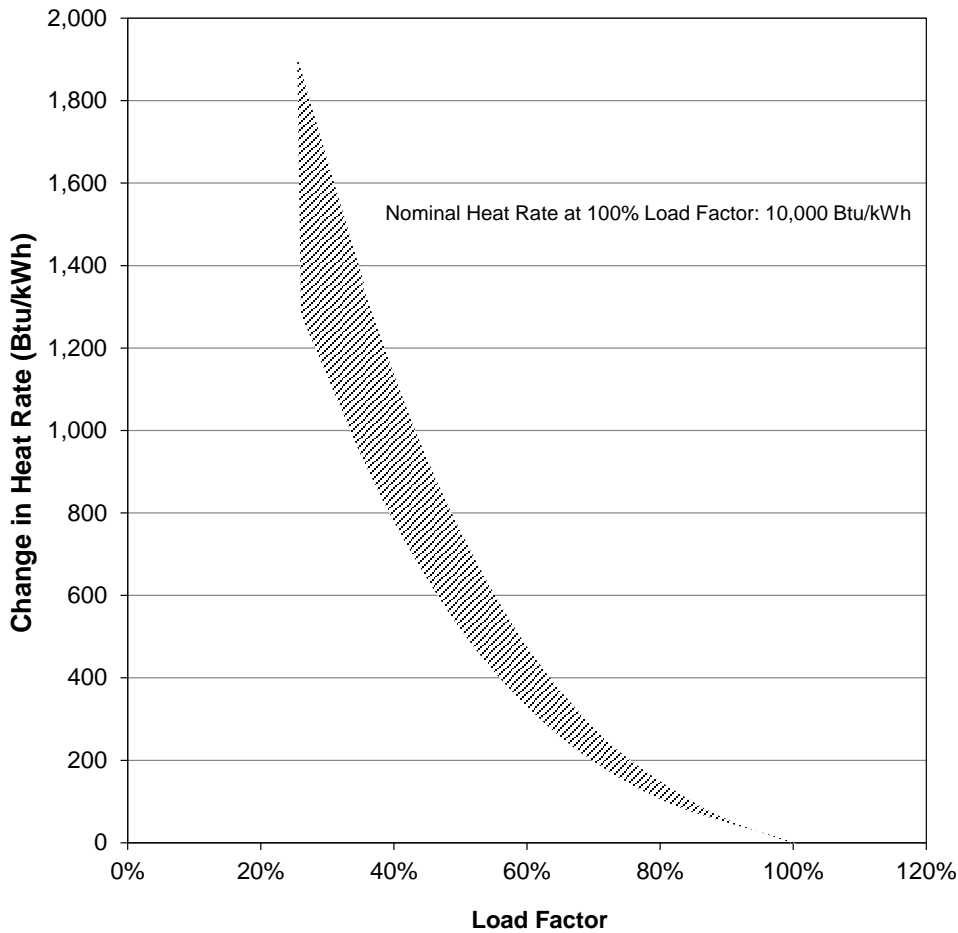


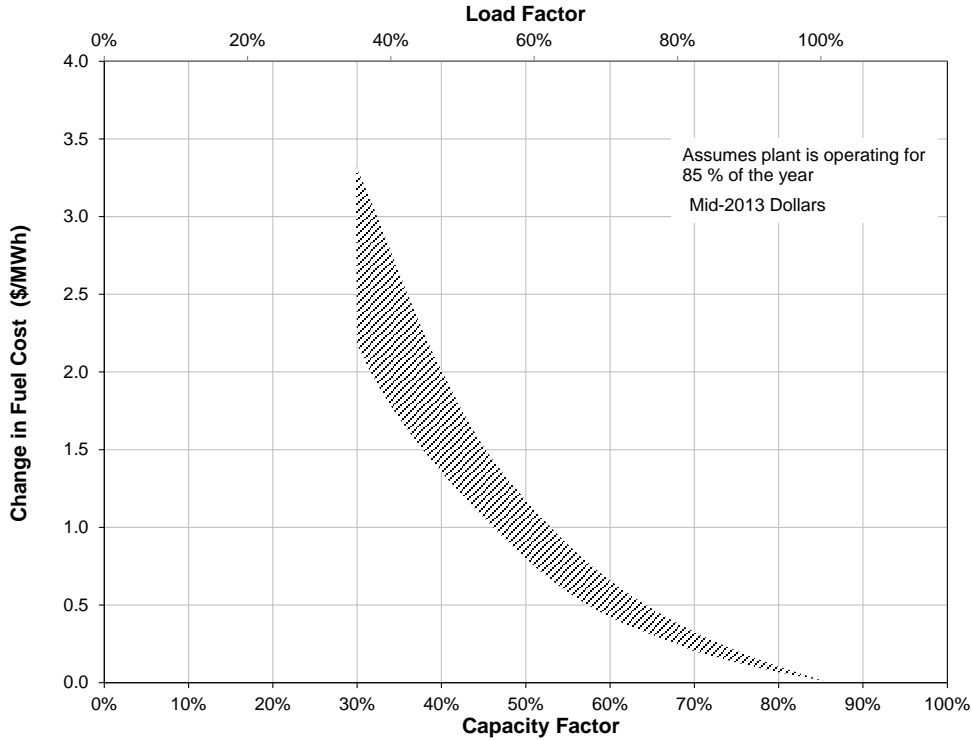
Exhibit 13 shows the impact of a reduction in load factor on the fuel cost portion of COE (due to increased heat rate, as shown in Exhibit 12) for a single cold start. Exhibit 13 shows that at lower load factors, the fuel cost portion of COE increases. For example, reducing the load factor from 100 to 70 percent (which effects a reduction in capacity factor from 85 percent to 60 percent) corresponds to a \$0.55/MWh increase in the COE due to greater fuel requirements. This represents a 2.3% increase in fuel costs⁹. If the plant is instead required to operate at a capacity factor of 50 percent by reducing load (about 58 percent load factor), the fuel cost portion of the COE from the additional fuel cost increases to \$1.00/MWh (on average), a 4.2% increase in fuel costs. Exhibit 13 reinforces that the fuel cost impact of operating at reduced load factor (due to adverse heat rate impacts) is minimal. The more significant cost implication is due to increased wear on mechanical components, which may require more frequent inspection, repair, or

⁸ Curve based on WorleyParsons' engineering analysis of a 600 MW plant for a commercial client

⁹ Using the fuel price, heat rate, and capacity factor assumptions presented in Exhibit 5, the fuel cost portion of the base plant COE in this analysis is \$23.50/MWh.

replacement. In addition, fewer annual operating hours over which to spread fixed O&M and inspection expenses amplify the impact of this cost account relative to fuel costs.

Exhibit 13 Fuel Cost Changes as a Function of Load Factor



5.4 Impact of Decreased Load Factor and Capacity Factor on COE

The potential for reduced capacity factor operation of coal-fired generators in the future has utilities evaluating the economic impacts of shutdowns versus operating at a decreased load factor.

Exhibit 14 shows the cost implications of reducing capacity factor by shutting the unit down, compared to reducing load factor, for a single annual cold start. For a single cold start, the most economic operating philosophy (below capacity factor of approximately 70%) is to reduce generation by shutting the unit down when needed, while operating at 100% load factor.

Exhibit 14 Impact of Capacity Factor Reduction Strategy on Susceptible Component O&M and Fuel Costs for a Single Annual Cold Start

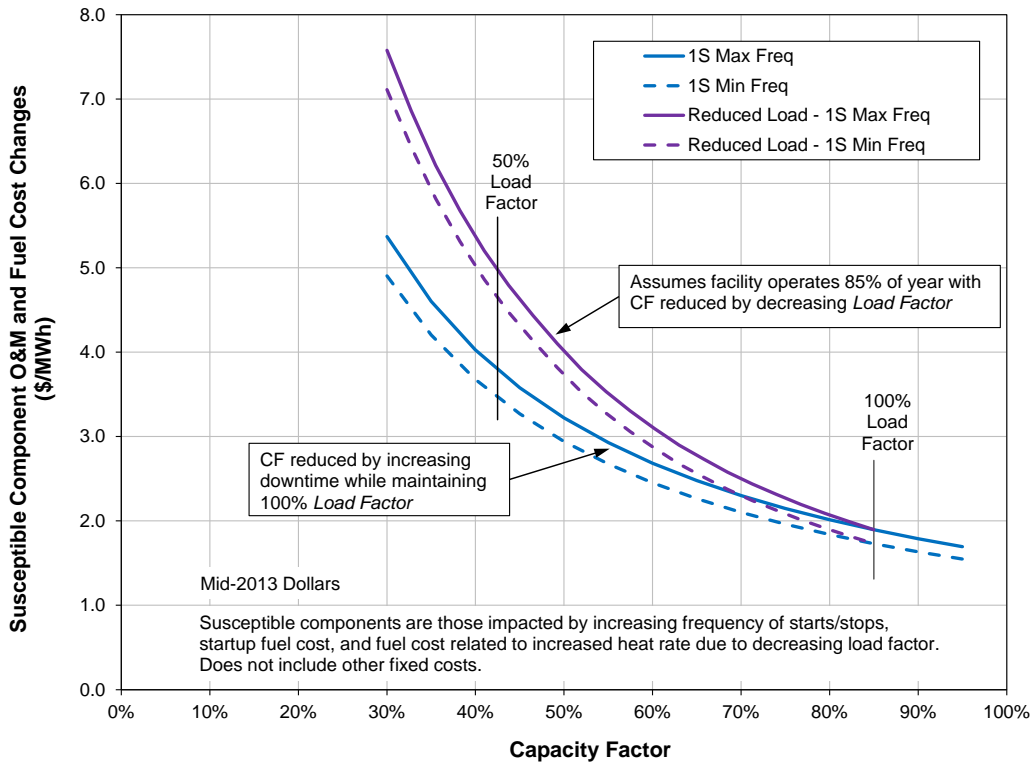


Exhibit 15 shows the same curves presented in Exhibit 14 – the cost impact of the different capacity factor reduction strategies that utilities may choose to adopt – with the addition of the 6 and 12 cold start cases.

The most cost-effective way to reduce annual capacity factor (shutting down or turning down the unit) is dependent upon what capacity factor is desired.

Exhibit 15 highlights the tradeoff between capital and operating cost associated with achieving a given annual capacity factor. For example, if a utility knows that a coal asset is limited to 40% annual capacity factor by regulatory factors, then the most economical way to do this is by simply shutting the unit down (as opposed to operating at a reduced load factor, represented by the purple line in Exhibit 15). The least expensive operating mode is to operate the unit at 100% load factor for 5 months of the year, and shut down for the remaining 7 months. For operational reasons (such as reliability, unit age, fuel availability or other factors) more than a single shutdown and startup may be required. For example, 6 annual cold starts (represented by the red lines in Exhibit 15) may increase COE by approximately \$1.14/MWh, a 3% increase over the base case COE in Exhibit 5.

Alternatively, if 70% annual capacity factor is desired, the expected number of annual cold starts determines the least expensive approach. If multiple shutdowns are anticipated (such as 6, represented by the red line in Exhibit 15), then operating at

reduced load factor (purple line in Exhibit 15) may be the most economic mode of operation.

Exhibit 15 Impact of Capacity Factor Reduction Strategy on Susceptible Component O&M and Fuel Costs for Multiple Cold Starts

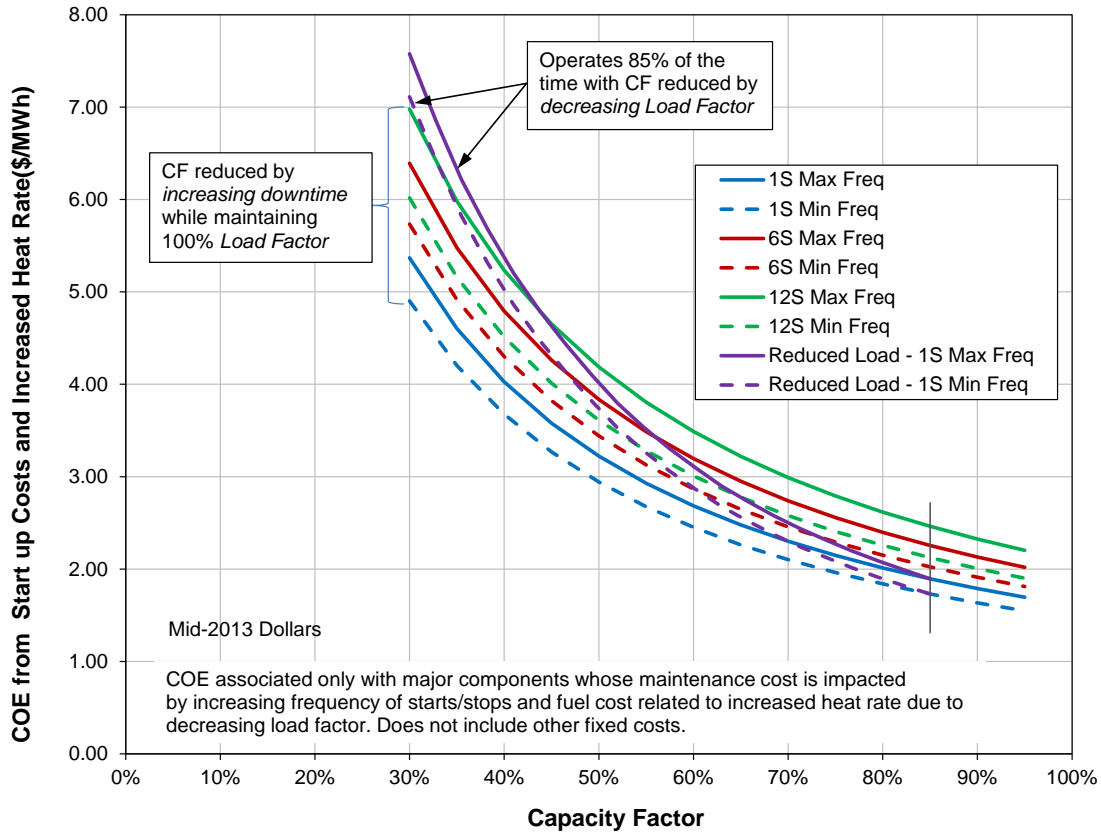
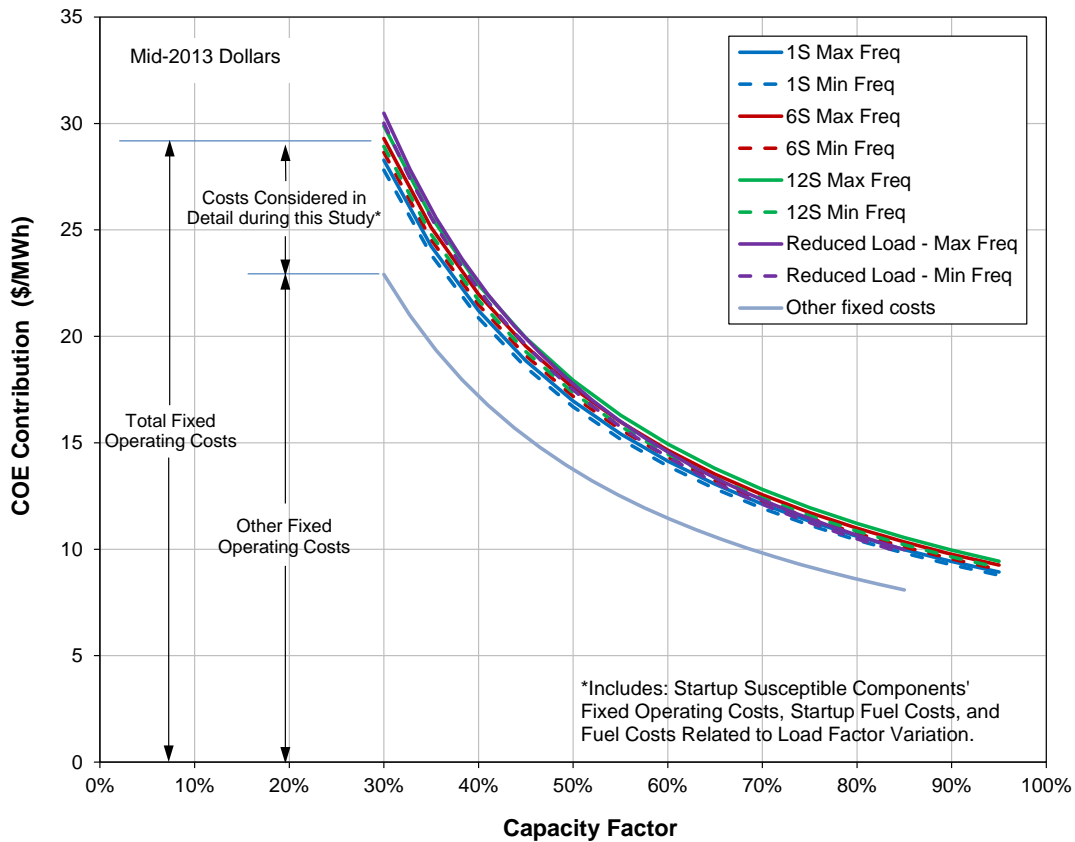


Exhibit 16 shows the total fixed O&M (O&M of susceptible components and other fixed costs), plus incremental fuel resulting from operating the unit at reduced load factor. The most significant impact on COE is by operating the unit at reduced capacity factor, regardless of whether the reduction was achieved by cold starts or a decrease in load factor. This is supported by the tight cost band due to cold starts and load factor reduction (represented by the area between the purple line and dark blue line in Exhibit 16) across the entire spectrum of capacity factors considered. Since cold starts and load factor reduction do not significantly impact operating and fuel costs (as shown in Exhibit 16), the dominant factor of the COE increase is the reduction in generation. The reduced generation amplifies the cost impact of fixed costs, as the fixed costs remain the same but are spread out over a more limited number of kilowatt-hours.

Exhibit 16 Impact of Starts/Stops on the Total Plant Fixed O&M Portion of the COE

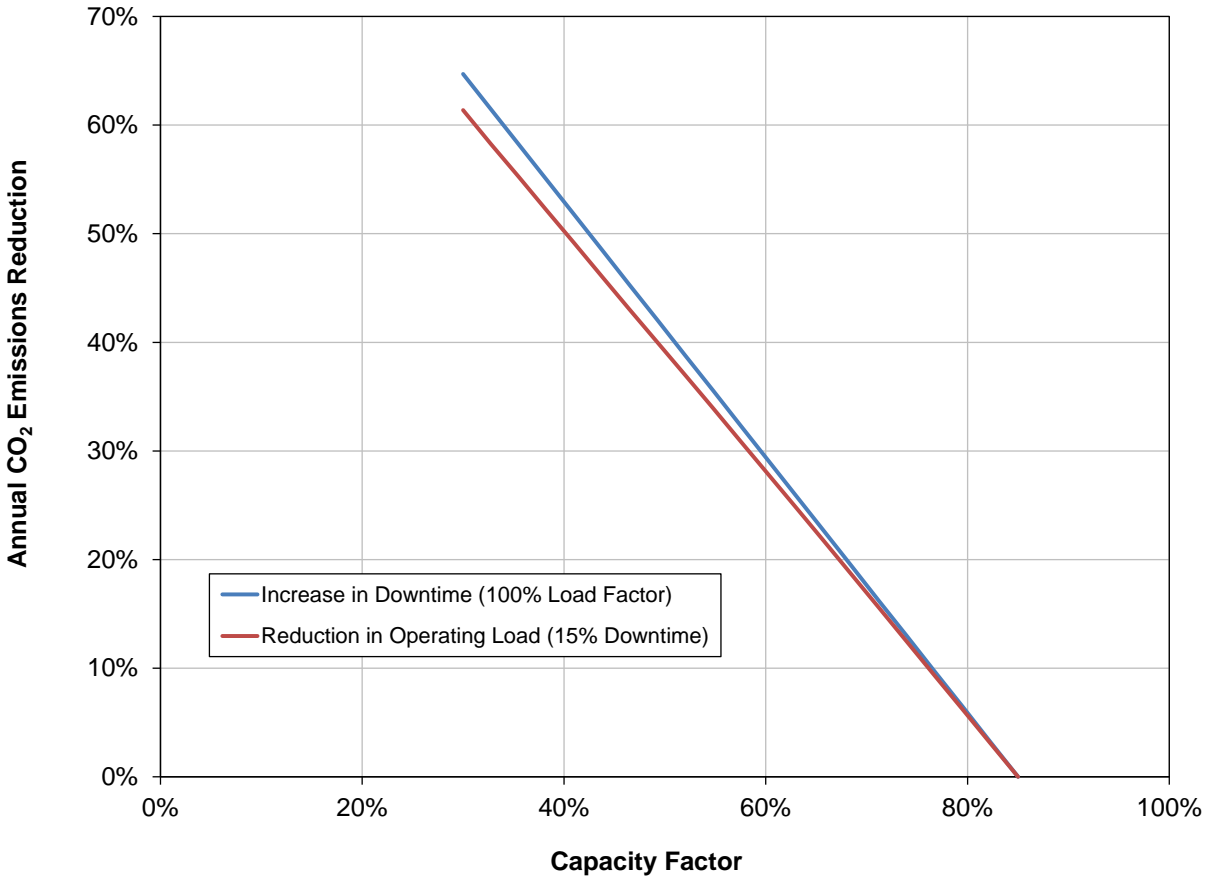


5.5 Impact of Reduced Capacity Factor on CO₂ emissions

In a broader effort to comply with regulatory policies directed at reducing CO₂ emissions from existing generation sources, utilities may consider decreasing a unit’s load factor and/or reducing operating hours via more frequent shutdowns to reduce fuel consumption and resulting CO₂ emissions. Exhibit 17 presents a comparison between the two approaches on the CO₂ emissions reduction. An annual capacity factor of 85 percent is used as the reference from which the CO₂ emission reduction is calculated.

Exhibit 17 shows that reducing operating hours and maintaining full operating load factor to reduce capacity factor has a slightly greater impact on CO₂ reduction than on decreasing load factor. The higher CO₂ emissions from the reduced load factor option is a result of the additional annual fuel consumption resulting from the increased heat rate as illustrated in Exhibit 12.

Exhibit 17 Annual CO₂ Emissions Reduction by Decreasing Capacity Factor



6 Key Findings

The key findings from the report are as follows:

- The annual routine maintenance and inspection cost for susceptible components is as significant as the periodic replacement/maintenance cost at the high end of the replacement frequency range.
- The most significant impact on COE is by operating the unit at reduced capacity factor – where less total, annual kilowatt-hours are generated – regardless of whether the reduction was achieved by cold starts or a decrease in load factor.
- Additional maintenance for susceptible components and startup fuel costs could range from \$100/MW/Start to \$490/MW/Start depending on the number of cold starts between 1 and 12.
- The most cost-effective way to reduce annual generation (shutting down or turning down the unit) is dependent upon what total number of kilowatt-hours are desired. At low capacity factors, the most economic option is usually to operate at 100% load factor, and shut the unit down to meet the annual capacity factor desired. At higher capacity factors (greater than approximately 70%); it begins to

be more economical to operate at reduced load factor, and shut down less frequently if possible.

- The contribution of startup susceptible component maintenance cost and startup fuel cost to COE is about 20% of the total fixed O&M cost.
- Increasing cold starts/stops from 1 to 6 or 12 per year increases the total fixed costs by about 10%.

7 References

- ¹ Lefton, S.A., Hilleman, D.D. (2011). *Make Your Plant Ready for Cycling Operations*, Coal Power Magazine, August 2011.
- ² Lefton, S.A., Besuner, P.M. (2006). *The Cost of Cycling Coal Fired Power Plants*, Coal Power Magazine, 2006: 16-20.
- ³ Myles, P., Herron, S. (2012). *Impact of Load Following on Power Plant Cost and Performance: Literature Review and Industry Interviews*, October 1st, 2012.
- ⁴ Kumar, N., Besuner, P.M., Lefton, S.A., Agan, D.D., Hilleman, D.D. (2012). *Power Plant Cycling Costs*, NREL/SR-5500-55433. Work performed by Intertek-APTECH, Sunnyvale, California. Golden, CO: NREL.
- ⁵ National Energy Technology Laboratory (NETL). (2010). *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity*. DOE/NETL-2010/1397, Pittsburgh, Pennsylvania.