GE
Energy Consulting

PJM Renewable Integration Study

Task 3A Part G

Plant Cycling and Emissions

Prepared for: PJM Interconnection, LLC.

Prepared by: General Electric International, Inc.

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imagination at work

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Acronyms and Nomenclatures

2% BAU	2% Renewable Penetration – Business-As-Usual Scenario
14% RPS	14% Renewable Penetration – RPS Scenario
20% LOBO	20% Renewable Penetration – Low Offshore Best Onshore Scenario
20% LODO	20% Renewable Penetration – Low Offshore Dispersed Onshore Scenario
20% HOBO	20% Renewable Penetration – High Offshore Best Onshore Scenario
20% HSBO	20% Renewable Penetration – High Solar Best Onshore Scenario
30% LOBO	30% Renewable Penetration – Low Offshore Best Onshore Scenario
30% LODO	30% Renewable Penetration – Low Offshore Dispersed Onshore Scenario
30% HOBO	30% Renewable Penetration – High Offshore Best Onshore Scenario
30% HSBO	30% Renewable Penetration – High Solar Best Onshore Scenario
AEPS	Alternative Energy Portfolio Standard
AGC	Automatic Generation Control
AWS/AWST	AWS Truepower
Bbl.	Barrel
BAA	Balancing Area Authority
BAU	Business as Usual
BTU	British Thermal Unit
CA	Intertek AIM's Cycling⬍Advisor ™ tool
CAISO	California Independent System Operator
CC/CCGT	Combined Cycle Gas Turbine
CEMS	Continuous Emissions Monitoring Systems
CF	Capacity Factor
CO2	Carbon Dioxide
CV	Capacity Value
DA	Day-Ahead
DR	Demand Response
DSM	Demand Side Management
EI	Eastern Interconnection

EIPC	Eastern Interconnection Planning Collaborative
ELCC	Effective Load Carrying Capability
ERCOT	Electricity Reliability Council of Texas
EST	Eastern Standard Time
EUE	Expected Un-served Energy
EWITS	Eastern Wind Integration and Transmission Study
FERC	Federal Energy Regulatory Commission
FLHR	Full Load Heat Rate
FSA	PJM Facilities Study Agreement
GE	General Electric International, Inc. / GE Energy Consulting
GE MAPS	GE's "Multi Area Production Simulation" model
GE MARS	GE's "Multi Area Reliability Simulation" model
GT	Gas Turbine
GW	Gigawatt
GWh	Gigawatt Hour
HA	Hour Ahead
HSBO	High Solar Best Onshore Scenarios
HOBO	High Offshore Best Onshore Scenarios
HR	Heat Rate
HVAC	Heating, Ventilation, and Air Conditioning
IPP	Independent Power Producers
IRP	Integrated Resource Planning
ISA	PJM Interconnection Service Agreement
ISO-NE	Independent System Operator of New England
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
lbs	Pounds (British Imperial Mass Unit)
LDC	Load Duration Curve

LM	Intertek AIM's Loads Model ™ tool
LMP	Locational Marginal Prices
LNR	Load Net of Renewable Energy
LOBO	Low Offshore Best Onshore Scenarios
LODO	Low Offshore Dispersed Onshore Scenarios
LOLE	Loss of Load Expectation
MAE	Mean-Absolute Error
MAPP	Mid-Atlantic Power Pathway
MMBtu	Millions of BTU
MVA	Megavolt Ampere
MW	Megawatts
MWh	Megawatt Hour
NERC	North American Electric Reliability Corporation
NOx	Nitrogen Oxides
NREL	National Renewable Energy Laboratory
NWP	"Numerical Weather Prediction" model
O&M	Operational & Maintenance
PATH	Potomac Appalachian Transmission Highline
PJM	PJM Interconnection, LLC.
PPA	Power Purchase Agreement
PRIS	PJM Renewable Integration Study
PRISM	Probabilistic Reliability Index Study Model
PROBE	"Portfolio Ownership & Bid Evaluation Model" of PowerGEM
PSH	Pumped Storage Hydro
PV	Photovoltaic
REC	Renewable Energy Credit
Rest of EI	Rest of Eastern Interconnection
RPS	Renewable Portfolio Standard
RT	Real Time

RTEP	Regional Transmission Expansion Plan
SC/SCGT	Simple Cycle Gas Turbine
SCUC/EC	Security Constrained Unit Commitment / Economic Dispatch
SOx	Sulfur Oxides
ST	Steam Turbine
TARA	“Transmission Adequacy and Reliability Assessment” software of PowerGEM
UCT	Coordinated Universal Time
VOC	Variable Operating Cost
WI	Western Interconnection

1 Power Plant Cycling Cost Analysis

1.1 Cycling Analysis Section Acknowledgement

This is to acknowledge that the material in this section describing the cycling analysis approach, methodology, terminology and definitions, and related figures and tables are, in most cases, taken verbatim from a NREL report previously developed by the Intertek AIM (formerly APTECH) team, based on permission granted by NREL to Intertek AIM in Appendix C-1 of their contract, as indicated below.

NREL Report:

Power Plant Cycling Costs

April 2012

N. Kumar, P. Besuner, S. Lefton, D. Agan, and D. Hilleman

Intertek APTECH

Sunnyvale, California NREL Technical Monitor: Debra Lew

Subcontract Report

NREL/SR-5500-55433

July 2012

Contract No. DE-AC36-08GO28308

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1.2 Introduction to Cycling Analysis

Start-up/shutdown cycles and load ramping impose thermal stresses and fatigue effects on numerous power plant components. When units operate at constant power output, these effects are minimized. If cycling duty increases, the fatigue effects increase as well, thereby requiring increased maintenance costs to repair or replace damaged components.

The following technical approach was used to quantify the variable O&M (VOM) costs due to cycling for the various study scenarios:

- Characterize past cycling duty by examining historical operations data for the major types of thermal units in the PJM fleet; supercritical coal, subcritical coal, gas-fired combined cycle, large and small gas-fired combustion turbines[1].
- Quantify O&M costs for those levels of cycling duty based on Intertek AIM's O&M/cycling database for a large sample of similar types of units.
- Establish baseline of cycling O&M costs by unit type for the 2% BAU scenario.
- Calculate changes to cycling duty and O&M costs for new operational patterns in each of the study scenarios from annual production cost simulation results.

1.3 Cycling Analysis Executive Summary

Deregulated markets and increasing penetration of variable renewable generation are having a far-reaching impact on the operation of conventional fossil generation. For many utilities and plant operators, plant operations and maintenance (O&M) expenditures are the one cost area that is currently rising at a rate faster than inflation. To stay competitive, utilities need to better understand the underlying nature of their plant O&M costs, and take measures to use this knowledge to their advantage. A major root cause of this increase in O&M cost for many fossil units is unit cycling. Power plant operators and utilities have been forced to cycle aging fossil units that were originally designed for base load operation.

Cycling refers to the operation of electric generating units at varying load levels, including on/off, load following, and minimum load operation, in response to changes in system load requirements (see Figure 1-1). 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 for high temperature components by the phenomenon we call creep-fatigue interaction. While cycling-related 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 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, it may result in reduced overall plant life.

[1] Nuclear and hydro units were not evaluated since nuclear units operate at constant load and hydro units do not experience thermal fatigue damage from cycling.

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.

Several renewable integration studies, including this study of the PJM region, have recognized increased power plant cycling due to renewables. Additionally, most reports also list the need for more flexible generation in the generation mix to meet the challenge of ramping and providing reserve requirements. Intertek AIM has provided generic lower bound cycling costs for conventional fossil generation in this report. The report also lists the typical cycling cost of the "flexible" peaker power plants, as it is important to realize that while such plants are built for quick start and fast ramping capabilities, they are not inexpensive to cycle. There is still a cost to cycle such plants. Modern combined cycle plants also have constraints with HRSG reliability and have a cost to cycle. Finally, Intertek AIM has provided an overview of systems and components commonly affected by cycling and mitigation strategies to minimize this cost.

The electricity market has changed appreciably over the past decade, especially with the introduction of large amounts of non-dispatchable wind and solar power in some regional markets. Cycling a plant may be required for numerous business reasons and is not necessarily a bad practice; however it does increase maintenance costs and forced outages. But the decision to do so should be made by an owner who has full knowledge of all the available options and estimates of the real costs that must be paid, today or in the future, as a result of that decision. Every power plant is designed and operated differently. Therefore the cost of cycling of every unit is unique. Managing the assets to a least cost option is the business opportunity while responding to a changing market.

Overview

1. Asset management of a fleet must include all the costs including cycling costs some of which are often latent and not clearly recognized by operators and marketers.
2. Most small and, especially, large coal units were designed for baseload operation and hence, on average are higher cycling cost units. Thermal differential stresses from cycling result in early life failures compared to base load operation.
3. There are some important economies of scale for large coal (and other fossil Units), that lower their costs. So the highest costs per megawatt capacity, as plotted here, occur in some "abused" smaller coal units, especially for cold starts.
4. Once all operating costs including cycling are accounted for, the best system mix of generation can be matched to changing loads and market opportunities.

5. Combined Cycle units are estimated to share the largest burden of cycling operation in the scenarios. These units have the biggest change in their operation mandate from relative baseload historically to extensive cycling operation in various scenarios.

Start Cost Impacts

6. Cycling start costs have a very large spread or variation.
7. Median Cold Start cost for each of the generation types is about 1.5 to 3 times the Hot Start Capital and Maintenance Cost.
8. The Small Gas combustion turbine (CT) units have almost the same relatively low costs for hot, warm, and cold starts. That is because for many key components in these designed-to-cycle units, every start is cold.
9. Older combined cycle units were a step change in lower operating costs due to cycling efficiencies and were designed and operated as baseload units. Changing markets have resulted in variable operation and when operated in cycling mode these combined cycle units can have higher cycling costs compared to a unit specifically designed for cycling which can be seen from the distribution of costs
10. The combined cycle fleet, along with the smaller coal fired generation, performs the bulk of the on/off cycling in the different scenarios.
11. Historically, large supercritical power plants are operated at baseload and do not cycle much. However the forecasted operating profile of these units for the various scenarios includes small increases in on/off cycling but dramatic increase in the load follow or ramping. The increased number of such cycles results in a marked increase in the load follow related wear and tear costs on these units. Operating these units in cycling mode can often result in unit trips and cycling related failures. As a result of the false starts and trips, the real cost of cycling these units is significantly high. Moreover, these units cannot easily be brought online under these circumstances (say, a trip) and such factors are not fully captured in this dataset.

Baseload Variable Operations and Maintenance (VOM) Cost

12. The higher operating and maintenance costs of supercritical units can be observed from the baseload VOM cost data.
13. Small Gas CT units were found to have the least base load VOM cost, but these units typically operate in a cycling environment as peaking units (which have high “total” VOM Cost). Based on our methodology described in Figure 1-9, we attributed a significant portion of industry standard total VOM cost to cycling.

14. The overall trend in the various scenarios reflect a change in operating mandate from baseload to cycling which is also reflected in a redistribution of these costs. With increase cycling, we estimate increased cycling related VOM cost, versus baseload VOM cost.

Load Following and Ramping Costs

15. The coal fired units were the most expensive load following units. Most of these units were designed for base load operation and undergo significant damage due to change in operations. Damage from cycling operations can be limited to acceptable rates, but unit specific damage mechanisms must be well understood to manage and reduce the damage rates.
16. Increasing ramp rates during load following can be expensive for normal operations. Higher ramp rates result in higher damage and this is most easily seen on the coal fired units. While not a linear relationship, additional research is required to get further detail.
17. It is interesting to note that the 30% High Offshore Best Onsite scenario estimates almost a 100% increase in load following costs on the Supercritical Coal units. This is mostly attributed to the 20% increase in such cycling from historical trends.
18. Supercritical units also see a doubling of the startup ramp rates compared to historical actual rates. The combined cycle units are also forecasted to perform faster startups compared to their historical averages but this increase is more modest compared to the supercritical units and also reflects their design for cycling advantage.
19. The combined cycle units also have a higher ramp rate cost, due to the operational constraints on the Heat Recovery Steam Generator (HRSG) and Steam Turbine (ST). Emissions requirements often limit the ability of a CC unit to load follow below 50% or even 75% for some designs. These costs need to be quantified.
20. Intertek AIM has seen a growing trend of minimum generation to maximum capacity type load follow cycling, due to increased renewable generation on the grid. This will result in higher costs and should be analyzed in a future study.

Mitigation Strategies

21. How can we avoid “system” cycling costs?

   a. Cycling costs can be avoided by the obvious method of not cycling a unit and that may include staying on line at a minimum or lower load at a small market loss price.
   b. Cycling costs may be managed by understanding the issues and managing the unit to reduce the damage rates
   c. Cycling costs may be managed by modifying the operational procedures or process (for example, keeping the unit "hot")
   d. Cycling cost may be reduced by capital or O&M projects to modify the base load designs to be better suited for cycling

22. Detailed component analysis allows for targeted countermeasures that address the root cause of the cycling damage to manage and even reduce the cost of future cycling duty. Some examples are:
    a. Air/Gas Side Operational Modifications – Reduces rapid transients in boiler flue gas
    b. Steam bypass – Matches steam temperature to turbine controls start up steam temperature in Superheater/Reheater (SH/RH)
    c. Feedwater bypass to condenser – Controls startup temperature ramp rates to feedwater heaters and economizers
    d. Condenser tube replacement – Improves plant chemistry and reliability and prevents turbine copper deposits.
    e. Motorized valve for startup – Reduces temperature ramp rates in boiler and reduces fatigue while providing a rapid and repeatable operation of critical components including drains.
    f. Motor driven boiler feed pump – Reduces fatigue of economizer and feedwater heaters and allows lower stress and faster, reliable start up.

Further Research

23. Determining cost to retrofit existing units to improve cycling capabilities.
24. Identifying additional or enhanced operational practices and procedures to integrated variable generation.
25. Defining the characteristics of the system (e.g., ramping requirements, minimum load levels, resource mix, etc.) to maintain reliability with increased variable generation.
26. Developing a universally accepted measure or index of flexibility to allow comparison across systems.

27. Developing a set of best practices to mitigate impacts of increased cycling.
28. Estimating the impacts of cycling on reduced life and reliability
29. Evaluating how integration costs change with changes to scheduled maintenance outages.
30. Transmission expansion modeling should not only include congestion and other physical constraints but also power plant cycling. Aggregating cycling costs at the system level results in ignoring the “flash flood” situation of heavy cycling on individual units on the grid.

1.4 Power Plant Cycling Costs – Introduction

This report presents generic industry historical data and estimated future power plant cycling costs for several types of electric generation units, as specified by PJM. Intertek AIM as part of the GE team has organized the cycling cost data in the following six generator plant types for the PJM Renewable Integration Study (PRIS):

1. Coal-fired sub-critical steam (35-900 MW)
2. Large coal-fired supercritical steam (500-1300 MW)
3. Gas-fired combined cycle (CT-ST and HRSG)
4. Gas-fired small CT (LM 6000, 5000, 2500 and similar models)
5. Gas-fired large frame CT (GE 7/9, N11, V94.3A, 501 and similar models)
6. Gas-fired steam (50-700 MW)

Intertek AIM conducted a comprehensive analysis to aggregate power plant cycling costs inputs to GE’s MAPS and PowerGEM’s Probe models for the six distinct groups described above. These costs are:

1. Hot, Warm, and Cold Start Costs
2. Base-load Variable operation and maintenance (VOM) costs
3. Load Following Costs (significant load follows)

Figure 1-1 illustrates several types of cycling events that cause fatigue damage, with cold starts having the greatest impact. A unit’s offline hours is used to determine the different start types and the corresponding costs. In addition to this, a load change determined as a percent of gross dependable capacity (GDC) is used to estimate the damage and cost associated with load following. For the purpose of this report, a change greater than 20% of GDC is called a significant load follow.

The data Intertek AIM have provided as a part of this report are based on the most appropriate and detailed cost-of-cycling studies Intertek AIM has done on several hundred units for many different clients. The development of the cost of cycling data input analysis has utilized the greatest sample size possible from Intertek AIM's database of generators tested and analyzed in the United States.

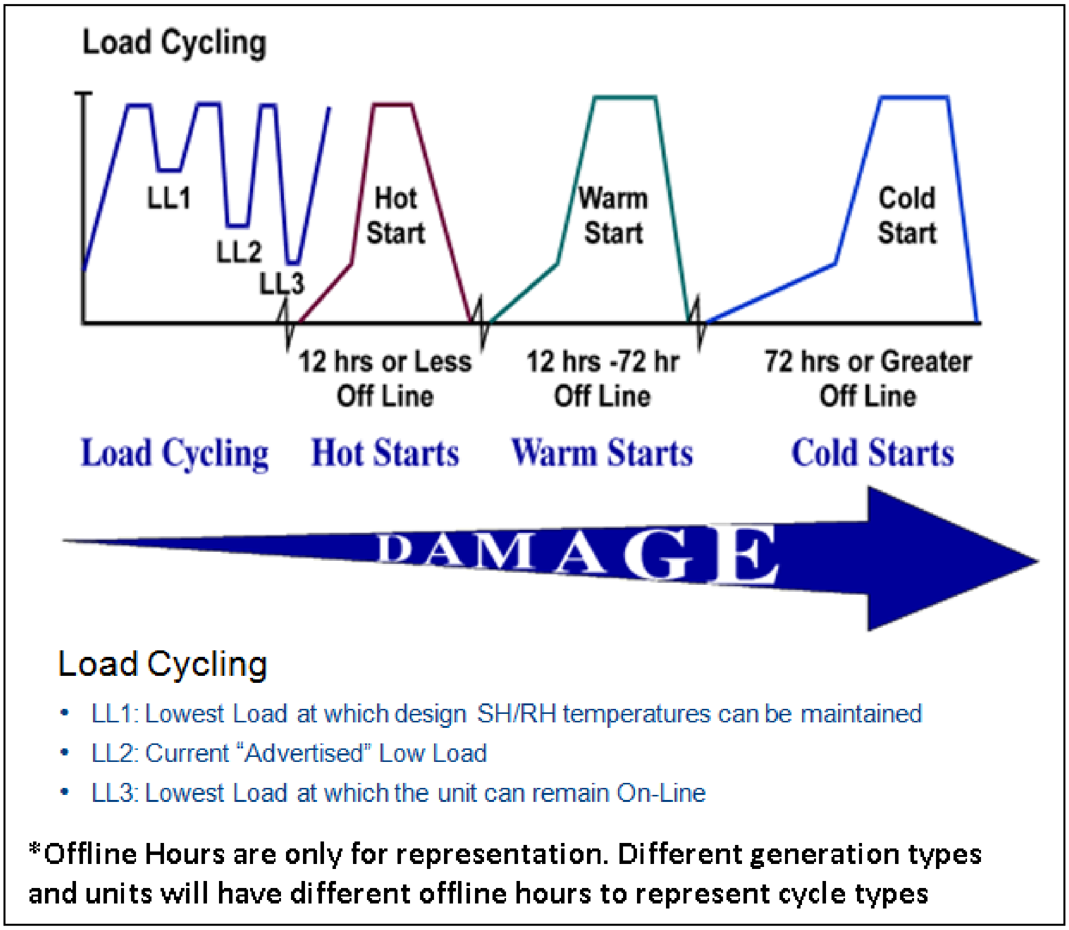

Figure 1-1: Types of Cycling Duty That Affect Cycling Costs

All costs have been calculated in 2012 US dollars. Also, to provide realistic cycling cost inputs, the sample of plants included in each of the groups has been carefully chosen to represent the variation of cycling costs for each group. For example, the first group (coal fired units), lower bound cycling costs represent the entire sample of sub-critical coal plants of unit size 35 MW to 1300 MW. As mentioned earlier, our goal is to capture the cost of cycling based on generation type and size only. However, in each group there are other variations, such as past operation, equipment manufacturer, fuel quality, unit design, etc., which affect cycling costs but are not disclosed in this report. These lower bound cycling costs were originally determined as part of National Renewable Energy Laboratory's (NREL's) Western Wind and Solar Integration Phase II Study (WWSIS II). These costs have been published, and are available publicly[2].

From these past studies, we extracted typical data on costs for each unit type that is representative of units that PJM and their stakeholders may evaluate. Further Intertek AIM analyzed the operating profile of a sample of 200 power plants in the PJM portfolio for the time period 2000-2012. This analysis in combination with the published cycling costs were used to form a baseline to represent cycling costs as they stand in 2012.

The GE team then performed production cost simulation of the PJM portfolio to represent different scenarios of renewable penetration (2% Business As Usual, 14%, 30% and 20% renewable penetration). Results from each of the scenario runs were then used to estimate the change in typical cycling costs from the 2012 baseline (see Figure 1-2[3]). The methods used in these past studies for developing the original cost of cycling estimates are briefly described in the following sections. We believe that this methodology is a step further from our work on the WWSIS Phase II study. We have analyzed operating profiles of units under different scenarios and updated the cycling costs to reflect the change in operations of these units.

[2] Source - Kumar, Besuner, Agan, Lefton - http://www.nrel.gov/docs/fy12osti/55433.pdf

[3] EHS is a term that relates the incremental damage that is estimated to occur as a result of the number and characteristics of various operational transients including shutdown + cold starts, shutdown + warm starts, shutdown + hot starts, low load and return to full load events, ramp rates, ranges, etc. Simply put, it is a measure of cycling damage.

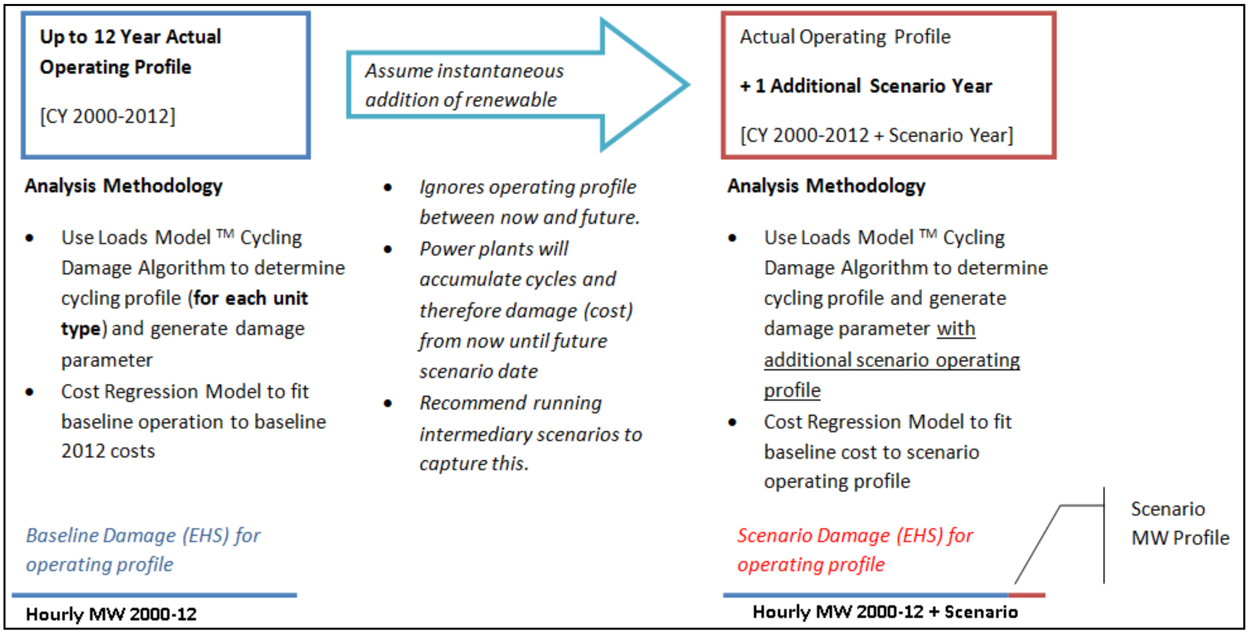

Figure 1-2: Cost of Cycling Estimation Procedure for Different Scenarios

1.5 Approach to Estimating Cycling Costs

Power plant cycling damage mechanisms leading to component failures are complex and usually involve multiyear time lagging. Intertek AIM started working on this problem more than 25 years ago by modeling life expenditure of individual critical components as a function of varying cycling operations. Since then, Intertek AIM has developed a multi-faceted approach that provides cycling cost estimates at a reasonable cost. Our approach uses multiple methods to derive and bound cycling cost estimates so that results can be validated. Figure 1-3 shows a simplified flowchart of this approach. Intertek AIM has used this methodology for hundreds of generation units owned by many utility clients throughout the world. The results and key power plant operating costs from these projects have been aggregated in the Intertek AIM Power Plant Cycling Database. For the purpose of this project, only the North American power plants were aggregated. Figure 1-4 presents the various sources of data for this cycling cost database and how this data is reported for this project. The outputs presented in this report are a subset of the information held in this comprehensive database.

We utilized unit/plant-specific information, industry data, and our experience on similar units, so as much relevant information as possible can be brought to bear. In our analysis, AIM uses two primary parallel approaches to analyzing cycling-related costs: (1) top-down analyses using unit composite damage accumulation models and statistical regression; and (2) modified bottom-up component-level studies using real-time monitoring data at key locations, prior engineering assessments of critical components, and a survey of plant personnel (See Section 1.12).

The results reported in this report, quantify the increase in capital, and operations and maintenance (O&M) costs of power plants due to increased cyclic operation.

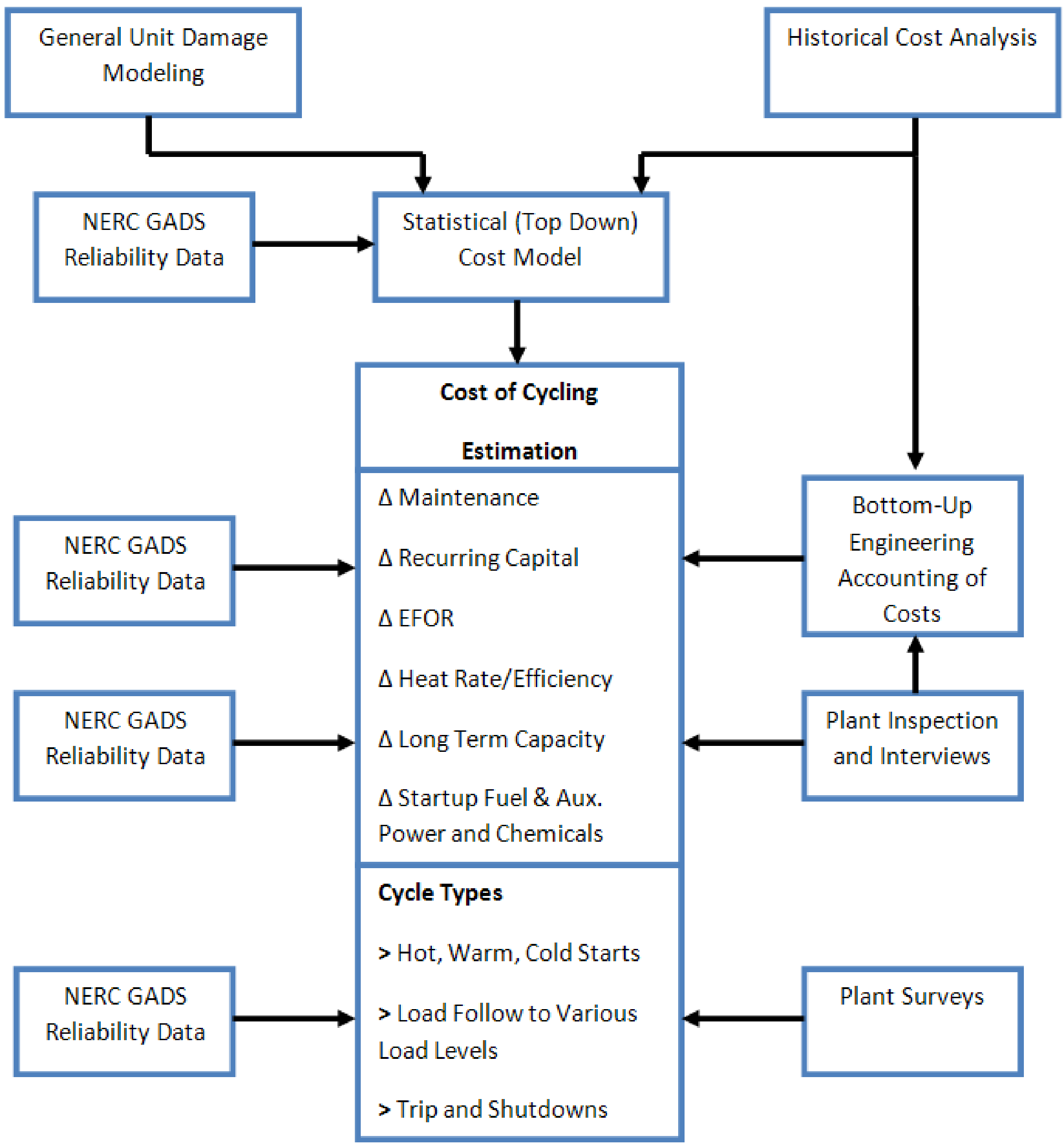

Figure 1-3: Cost of Cycling Estimation Procedure

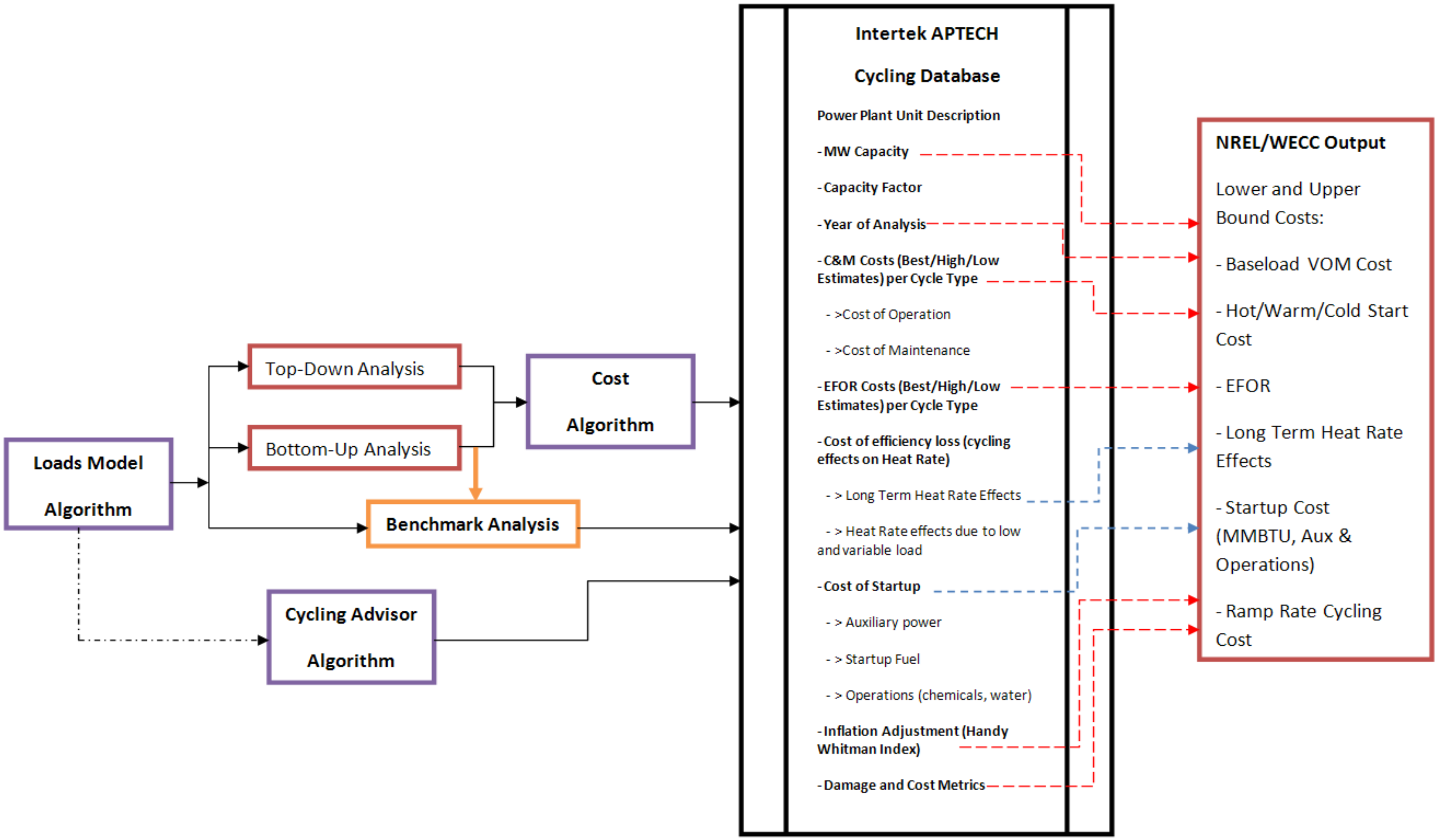

Figure 1-4: Intertek AIM Cost of Cycling Database

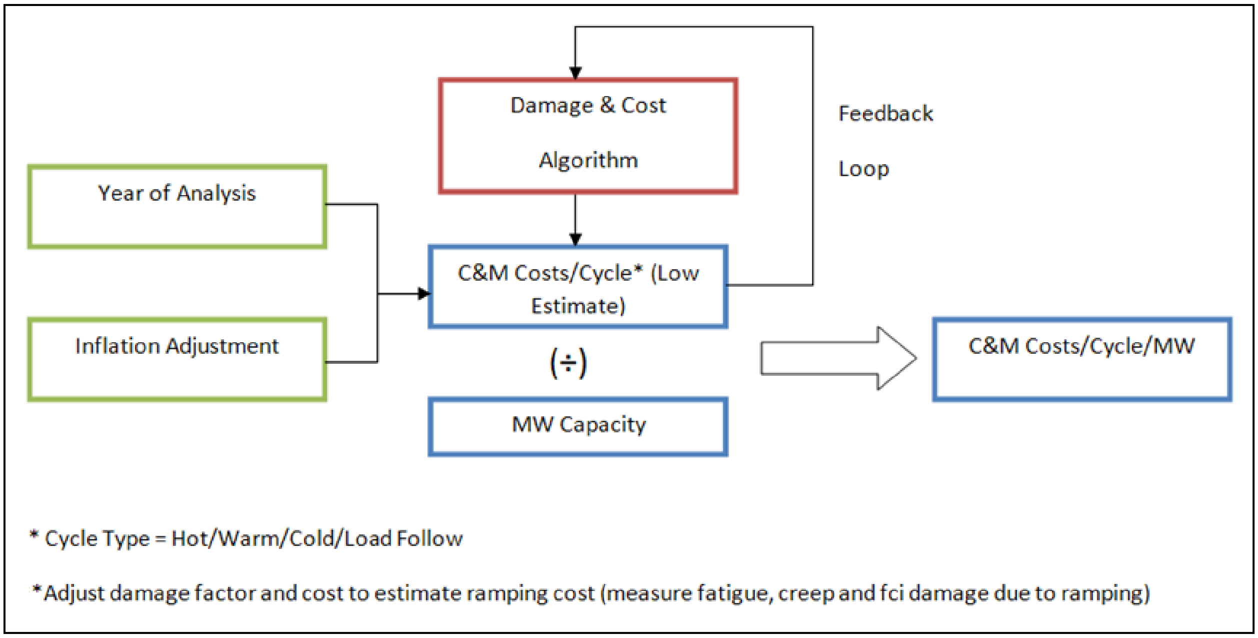

Figure 1-5: Estimating Lower Bound Start Cost

Figure 1-5 is the flowchart for generating the inflation adjusted cycling start costs. The Hot/Warm/Cold start cost was reported on per MW capacity basis and is the capitalized maintenance cost of cycling. This cost is the additional cost attributed to each additional on/off cycle. The feedback loop in the figure represents steps taken to update current plant operation from the time when a cycling study was originally performed.

As mentioned before, cycling cost is directly dependent on power plant operation and on some occasions Intertek AIM had to recalibrate the cost of cycling estimated in older studies. Therefore, we analyzed the hourly operating profile of about 200 sample power plants representing the six generation types to support our baseline costs. We believe that the cycling cost inputs reported in this document are reliable and typical averages for units that have been operated in conditions seen over the last 10 to 12 years.

As discussed before, Figure 1-2 provides a visual flowchart of our methodology to estimate power plant cycling costs for the different scenarios. Using this baseline costs to represent power plant cycling costs in 2012, we append the hourly MW scenario output data for every unit in our sample to determine changes in cycling costs with different levels of renewable integration in the PJM portfolio.

We summarize the change in operating profiles of the generation types by evaluating the change in:

- Hot, Warm and Cold Start Cost
- Number of annual or quarterly Hot, Warm and Cold Starts

- Significant Load Following Cost
- Number of annual or quarterly Significant Load Follows
- Baseload Variable Operations & Maintenance (VOM) Cost
- Ramp Rates, and other operational characteristics

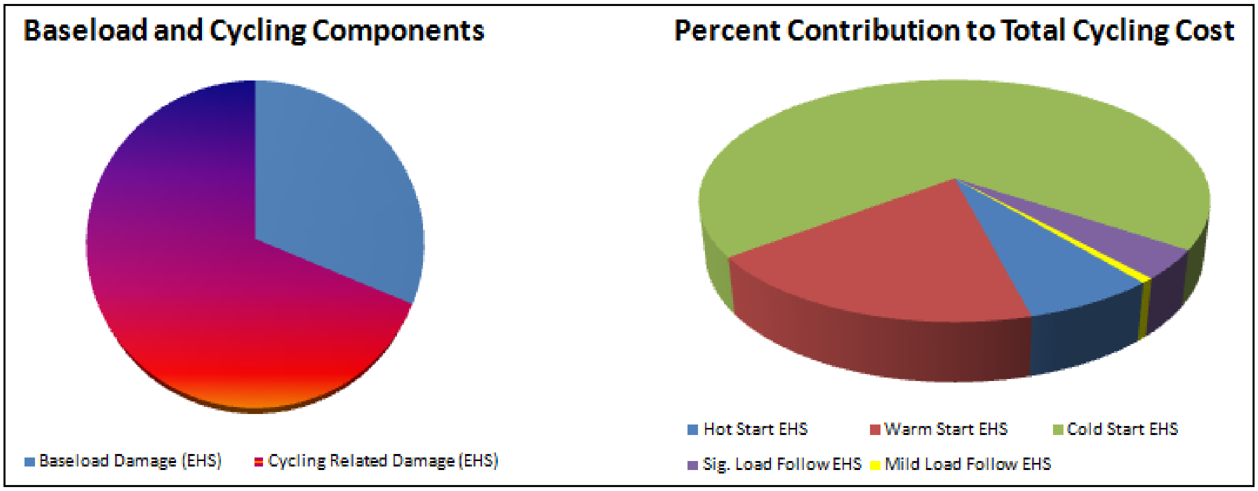

Figure 1-6: Characterizing EHS for Different Operating Profiles

Figure 1-6 shows how Intertek AIM's damage parameter EHS is used to characterize power plant cycling in this report. Each EHS has a baseload and cycling component which is determined by analyzing hourly MW data of a power plant. Every cycle type – hot, warm, and cold and load follow is represented by a certain baseload and cyclic component. We use these parameters to estimate changes in cost with changing operating profiles of the units in each scenario.

Power plant operators are well aware that load cycling causes accelerated damage to many unit components, causing increased equipment failures with resulting higher equipment forced outage rates (EFOR) and higher non-routine maintenance and capital replacement costs. With increased cycling, operators are putting their assets at increased risk of increased forced outages and High Impact Low Probability (HILP) events that they wish to minimize and avoid if possible (Figure 1-7). Figure 1-8 was generated using NERC-GADS data and shows that the Actual Plant Data Reflects Creep Fatigue Interaction Design Curve[4].

4 ASME creep-fatigue interaction curves

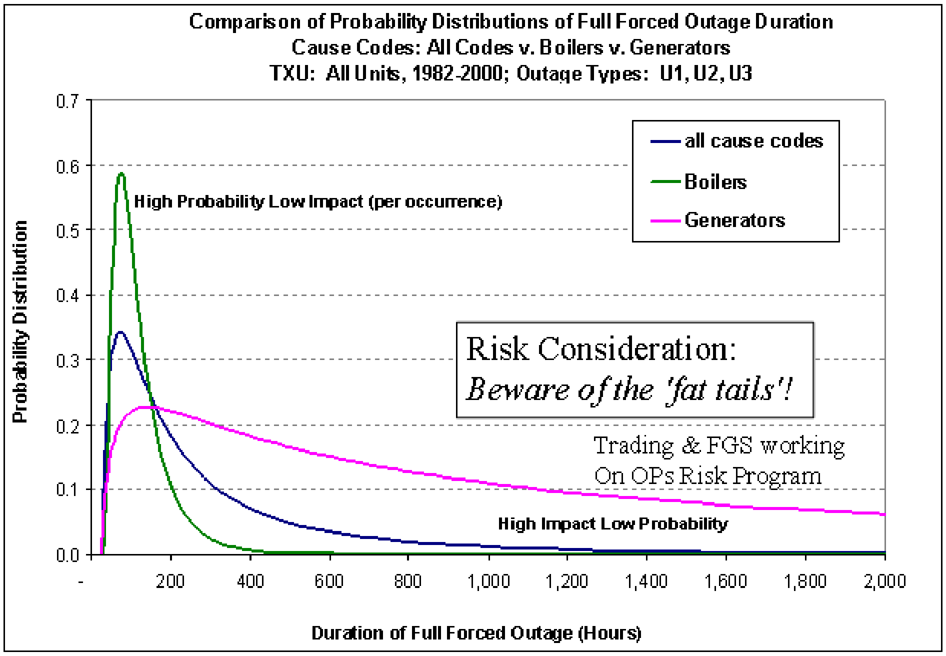

Figure 1-7: High Impact Low Probability Events

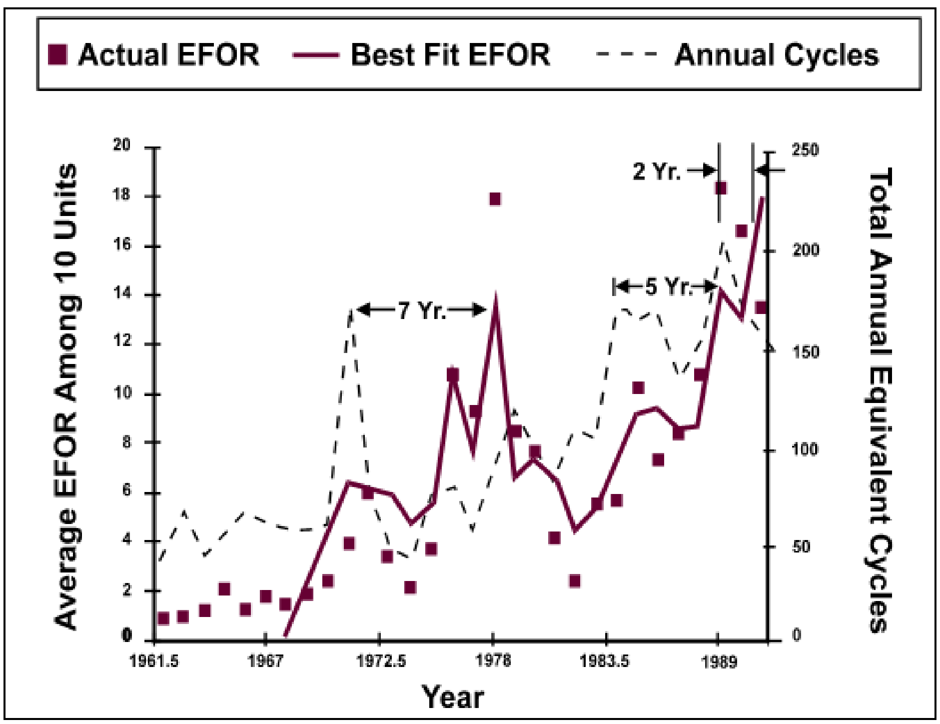

Figure 1-8: Cycling Effect on Plant Reliability

Note that, Intertek AIM's task was limited to provide aggregate cycling cost impacts to the production cost models and did not include impacts on reliability of power plants.

Figure 1-9 presents a flowchart to generate the baseload variable operations and maintenance (VOM) cost. Intertek AIM determines the cycling related O&M cost and subtracts that from industry standard and plant provided 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.

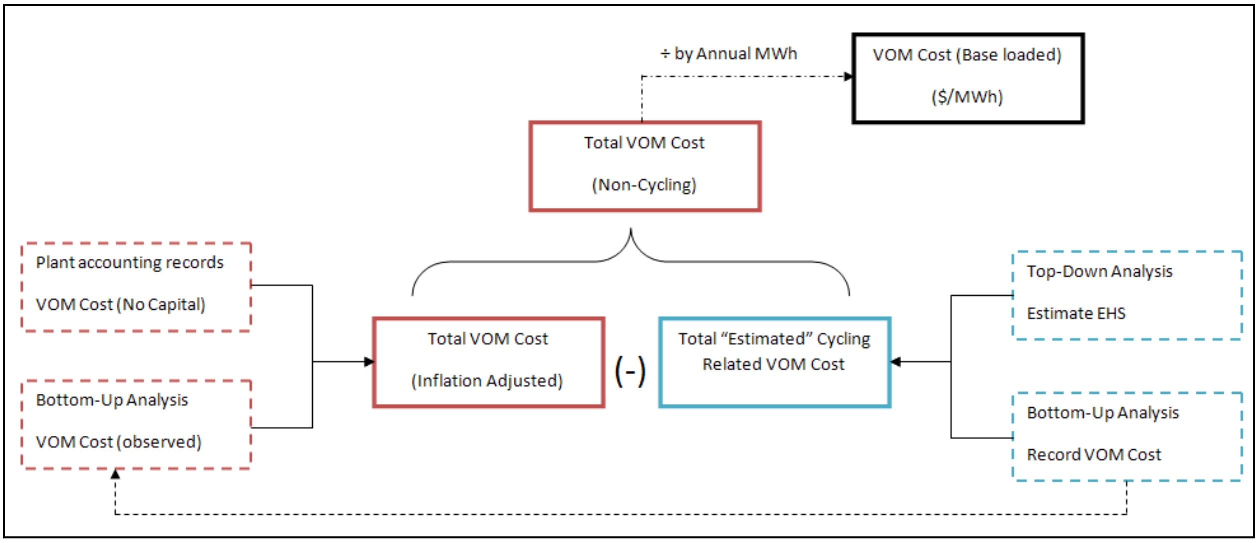

Figure 1-9: Estimating Baseload VOM Cost

What makes AIM's methodology especially powerful is our top-down method's ability to capture the effects of operator error and other obscure factors in its estimates of unit-wide cycling costs. The bottom-up accounting and modeling techniques are then used to break down the unit-wide cycling costs into component-specific costs. This detailed component analysis allows for targeted countermeasures that address the root cause of the cycling damage to manage and even reduce the cost of future cycling duty. Intertek AIM has leveraged its database of power plant cycling costs, as well as products of our rich and detailed methodology, to develop high level – "generic" cost inputs for PJM.

1.6 Cycling Analysis Results

Figure 1-10 shows the spread of baseline start costs for all units included in this project and published as part of the WWSIS Phase II. It is apparent from these plots that power plant cycling costs have a large variation and depend on several factors such as:

- Design
- Vintage

- Age
- Operation and maintenance history and procedure

We use a combination of these factors to define a generating unit's cycling susceptibility. For instance, units in a given generation type of similar age, vintage, design and O&M history and procedures should have somewhat similar damage from cycling operation. Additionally, for the sake of consistency and simplicity, the median value of the cycling costs was aggregated for inputs to the production cost simulations.

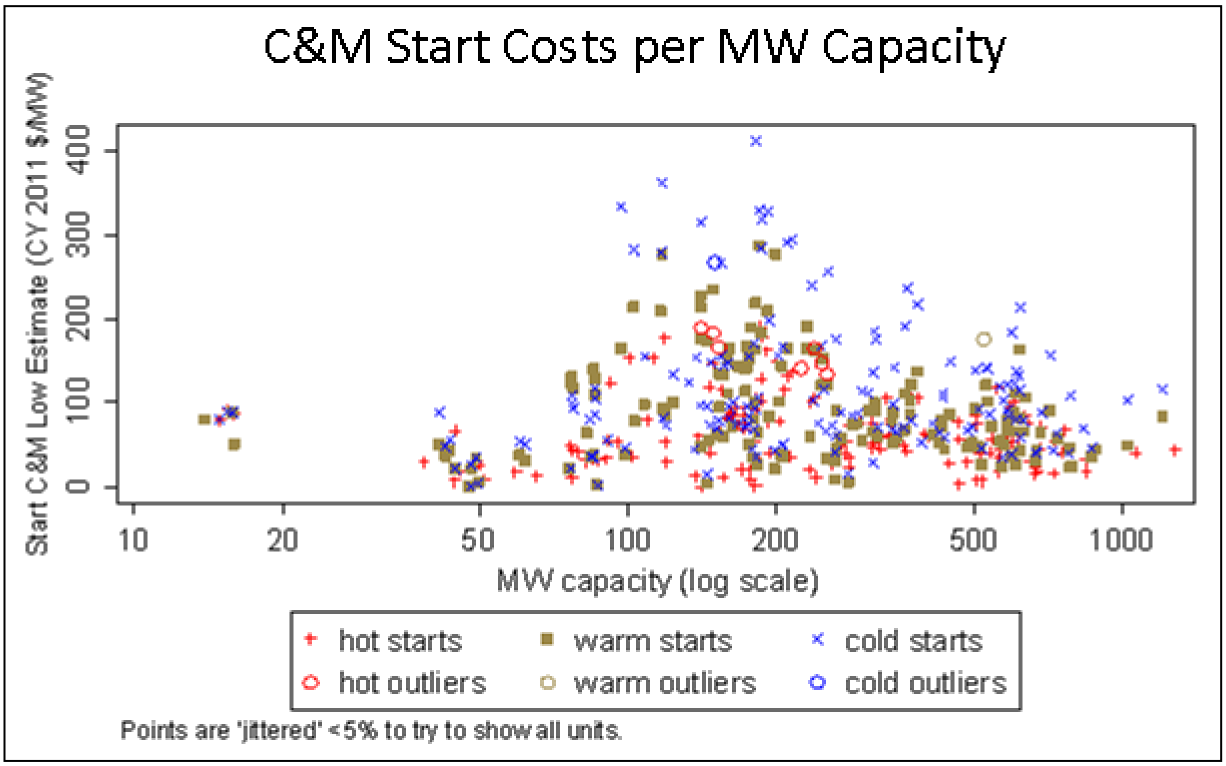

Figure 1-10: Capital and Maintenance Start Costs per MW Capacity[5]

1.7 Start Cost Impacts

One of the key outputs of the report is the Capital and Maintenance - Hot, Warm and Cold start costs[6]. Typical definitions of the cycling related costs are:

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[5] As estimated for the WWSIS Phase II Study.

[6] Note that these costs do not include the fuel cost required for the startup, which is being reported separately.

Cost of operation, maintenance and capital–

- Cost includes:
  - operator non-fixed labor,
  - general engineering and management cost (including planning and dispatch);
- Cost excludes:
  - fixed labor,
  - fixed maintenance and overhaul maintenance expenditures for boiler, turbine, generator, air quality control systems and balance of plant key components

Cost of operation –

- Cost includes:
  - operator non-fixed labor,
  - general engineering and management cost (including planning and dispatch);
- Cost excludes:
  - excludes fixed labor

Cost of maintenance –

- Cost includes:
  - maintenance and overhaul maintenance expenditures for boiler, turbine, generator, air quality control systems and balance of plant key components

Cost of capital maintenance –

- Cost includes:
  - overhaul capital maintenance expenditures for boiler, turbine, generator, air quality control systems and balance of plant key components

Additionally Intertek AIM records the following costs separately:

- Cost of forced outage and derate effects, including forced outage time, replacement energy, and capacity.

It should be emphasized that there are large variations in costs between individual units of each type, and that the numbers provided by Intertek AIM are *generic low bounds*[7]. All cost numbers in this report have been adjusted for calendar year 2013$.

Table 1-1 to Table 1-10 presents the estimated cycling cost results for each unit type for all the scenarios (based on the sample of units analyzed). These tables also present other basic data for each unit type such as: (1) Warm Start "Offline" Hours, (2) Load Following Cost (Typical Ramp Rates ($/MW Capacity per Load Follow), and (3) non-cycling related baseload variable O&M costs ($/MWH). In general, the baseline costs in the tables are costs determined by Intertek AIM for the WWSIS Phase II study. The costs estimated for each of the scenarios represents the relative change (positive or negative) in costs when the cycling is included in each of the new scenarios for an additional one year.

The typical ranges of "hour offline" for warm starts for each unit type are also presented - any start duration below this range would be a hot start, and any above this range would be a cold start.

As described, a power plant cycling can be classified either as on/off cycling or load follow cycling, which refers to a change in generation from maximum capacity to lower or minimum load. The load follow cycling is further classified by Intertek AIM as significant load following and mild load following. These tables provide the estimates for the costs of the "significant" load follow cycles. Depending on the unit, Intertek AIM regards all cycles of MW range greater than 20% gross dependable capacity (GDC) as significant.

In the case of the 14% RPS scenario, presented in Table 1-2, a significant increase in hot (40%), warm (24%), and cold (23%) start cost on the combined cycle units is observed. There is also a significant difference in the cold start cost of the supercritical coal units. The scenario represents a situation where the majority of on/off cycling is provided by the combined cycle units. Moreover, a vast majority of the load following cycle is shifted to the large coal units and in particular the supercritical coal units. As explained earlier, we analyzed the cycling and non-cycling variable O&M costs, to avoid double counting. The table represents a drop in baseload VOM costs since a majority of this cost is shifted to cycling related wear and tear.

The 20% HSBO scenario results presented in Table 1-6 shows the costs of hot, warm and cold starts on the combined cycle increase by 22%, 29% and 5% respectively. While, the cold start costs on the supercritical coal units increases by 43%. Again, a majority of the

[7] Care should be taken to implement the cycling cost. For example if a unit goes through 200 starts per year and the start cost is underestimated by $1000/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.

significant load following is provided by the larger coal units thus resulting in a higher cost associated with load follow or ramping wear and tear.

The 30% HOBO scenario results presented in Table 1-9, forecasts a very different operating pattern for the fossil generation. While the combined cycle units have slightly higher warm start cost at $76 per MW capacity, a 34% increase, the hot and warm start costs don’t change significantly. Interestingly, the biggest change in cycling wear and tear costs is on the supercritical coal load follow or ramping costs, which double from previous estimates.

Table 1-1: Estimated Costs of Cycling and Other Data for Various Generation Types (2% BAU)

Unit Type	Hot Start - C&M cost ($/MW cap.)			Warm Start - C&M cost ($/MW cap.)			Cold Start - C&M cost ($/MW cap.)			**Hot, Warm, Cold Start Definitions**
	Baseline*	2% BAU**	%Change	Baseline*	2% BAU**	%Change	Baseline*	2% BAU**	%Change	Typical WS Hours Offline
Subcritical Coal	78.7	82.0	4.1%	114.2	118.5	3.7%	129.7	145.8	12.4%	8 to 48 Hours
Supercritical Coal	55.6	55.6	0.0%	65.9	65.9	0.0%	107.0	157.5	47.2%	24 to 120 Hours
Combined Cycle [GT+HRSG+ST]	36.0	52.7	46.4%	56.6	67.0	18.4%	81.3	95.9	17.9%	12 to 72 Hours
Small Gas CT	19.6	19.6	0.0%	24.7	26.4	6.8%	32.9	34.1	3.6%	4 to 5 Hours
Large Gas CT	32.9	32.9	0.0%	56.0	56.3	0.5%	92.2	96.1	4.2%	5 to 40 Hours
Gas Steam	37.0	-	-	59.7	-	-	77.2	-	-	4 to 48 Hours
Unit Type				**Sig. Load Follow Cost ($/MW cap.)**			**Baseload VOM Cost ($/MWh)**			
				Baseline*	2% BAU**	%Change	Baseline*	2% BAU**	%Change	
Subcritical Coal				2.98	3.0	0.0%	2.70	2.63	-3%	
Supercritical Coal				2.02	2.0	0.0%	2.96	2.83	-4%	
Combined Cycle [GT+HRSG+ST]				0.66	0.7	9.1%	1.02	0.48	-53%	
Small Gas CT				0.65	0.7	0.8%	0.64	0.60	-6%	
Large Gas CT				1.64	1.6	0.0%	0.66	0.63	-4%	
Gas Steam				1.98	2.0	0.0%	0.92	0.92	0	

*Source - Kumar, Besuner, Agan, Lefton - http://www.nrel.gov/docs/fy12osti/55433.pdf

** - Changes in operating profiles to achieve 2% BAU were not included.

Cycling damage and costs accumulate and increase with increasing cycles, therefore the future costs are path dependent

e. g. increasing cycles in the future years will increase the future cycling costs

Table 1-2: Estimated Costs of Cycling and Other Data for Various Generation Types (14% RPS)

Unit Type	Hot Start - C&M cost ($/MW cap.)			Warm Start - C&M cost ($/MW cap.)			Cold Start - C&M cost ($/MW cap.)			**Hot, Warm, Cold Start Definitions**
	Baseline*	14% RPS**	%Change	Baseline*	14% RPS**	%Change	Baseline*	14% RPS**	%Change	Typical WS Hours Offline
Subcritical Coal	78.7	82.0	4.1%	114.2	118.7	3.9%	129.7	150.8	16.3%	8 to 48 Hours
Supercritical Coal	55.6	55.6	0.0%	65.9	65.9	0.0%	107.0	166.9	55.9%	24 to 120 Hours
Combined Cycle [GT+HRSG+ST]	36.0	50.6	40.4%	56.6	70.3	24.3%	81.3	99.9	22.9%	12 to 72 Hours
Small Gas CT	19.6	19.9	1.6%	24.7	25.7	4.1%	32.9	34.6	5.0%	4 to 5 Hours
Large Gas CT	32.9	32.9	0.0%	56.0	57.1	1.9%	92.2	95.4	3.4%	5 to 40 Hours
Gas Steam	37.0	-	-	59.7	-	-	77.2	-	-	4 to 48 Hours
Unit Type				**Sig. Load Follow Cost ($/MW cap.)**			**Baseload VOM Cost ($/MWh)**			
				Baseline*	14% RPS**	%Change	Baseline*	14% RPS**	%Change	
Subcritical Coal				3.0	3.1	3.7%	2.70	2.62	-3%	
Supercritical Coal				2.0	2.2	11.5%	2.96	2.84	-4%	
Combined Cycle [GT+HRSG+ST]				0.7	0.7	7.1%	1.02	0.42	-59%	
Small Gas CT				0.6	0.7	2.0%	0.64	0.61	-5%	
Large Gas CT				1.6	1.6	0.3%	0.66	0.63	-5%	
Gas Steam				2.0	2.0	0.0%	0.92	0.92		

*Source - Kumar, Besuner, Agan, Lefton - http://www.nrel.gov/docs/fy12osti/55433.pdf

** - Changes in operating profiles to achieve 14% RPS were not included.

Cycling damage and costs accumulate and increase with increasing cycles, therefore the future costs are path dependent

e. g. increasing cycles in the future years will increase the future cycling costs

Table 1-3: Estimated Costs of Cycling and Other Data for Various Generation Types (20% LOBO)

Unit Type	Hot Start - C&M cost ($/MW cap.)			Warm Start - C&M cost ($/MW cap.)			Cold Start - C&M cost ($/MW cap.)			**Hot, Warm, Cold Start Definitions**
	Baseline*	20% LOBO**	%Change	Baseline*	20% LOBO**	%Change	Baseline*	20% LOBO**	%Change	Typical WS Hours Offline
Subcritical Coal	78.7	82.7	5.0%	114.2	119.6	4.7%	129.7	148.3	14.3%	8 to 48 Hours
Supercritical Coal	55.6	55.6	0.0%	65.9	65.9	0.0%	107.0	154.8	44.6%	24 to 120 Hours
Combined Cycle [GT+HRSG+ST]	36.0	46.5	29.2%	56.6	74.5	31.5%	81.3	89.5	10.1%	12 to 72 Hours
Small Gas CT	19.6	20.0	2.2%	24.7	25.5	3.4%	32.9	33.8	2.8%	4 to 5 Hours
Large Gas CT	32.9	33.5	1.9%	56.0	57.1	1.9%	92.2	95.3	3.4%	5 to 40 Hours
Gas Steam	37.0	-	-	59.7	-	-	77.2	-	-	4 to 48 Hours
Unit Type				**Sig. Load Follow Cost ($/MW cap.)**			**Baseload VOM Cost ($/MWh)**			
				Baseline*	20% LOBO**	%Change	Baseline*	20% LOBO**	%Change	
Subcritical Coal				3.0	3.2	7.4%	2.70	2.61	-3%	
Supercritical Coal				2.0	2.6	30.8%	2.96	2.80	-5%	
Combined Cycle [GT+HRSG+ST]				0.7	0.7	0.0%	1.02	0.36	-65%	
Small Gas CT				0.6	0.7	2.0%	0.64	0.61	-4%	
Large Gas CT				1.6	1.7	1.3%	0.66	0.64	-3%	
Gas Steam				2.0	2.0	0.0%	0.92	0.92		

*Source - Kumar, Besuner, Agan, Lefton - http://www.nrel.gov/docs/fy12osti/55433.pdf

** - Changes in operating profiles to achieve 20% LOBO were not included.

Cycling damage and costs accumulate and increase with increasing cycles, therefore the future costs are path dependent

e. g. increasing cycles in the future years will increase the future cycling costs

Table 1-4: Estimated Costs of Cycling and Other Data for Various Generation Types (20% LODO)

Unit Type	Hot Start - C&M cost ($/MW cap.)			Warm Start - C&M cost ($/MW cap.)			Cold Start - C&M cost ($/MW cap.)			**Hot, Warm, Cold Start Definitions**
	Baseline*	20% LODO**	%Change	Baseline*	20% LODO**	%Change	Baseline*	20% LODO**	%Change	Typical WS Hours Offline
Subcritical Coal	78.7	82.6	5.0%	114.2	122.2	7.0%	129.7	148.8	14.8%	8 to 48 Hours
Supercritical Coal	55.6	55.6	0.0%	65.9	65.9	0.0%	107.0	152.6	42.6%	24 to 120 Hours
Combined Cycle [GT+HRSG+ST]	36.0	45.4	26.0%	56.6	75.8	33.9%	81.3	89.3	9.9%	12 to 72 Hours
Small Gas CT	19.6	20.0	2.2%	24.7	25.5	3.4%	32.9	33.9	2.8%	4 to 5 Hours
Large Gas CT	32.9	33.3	1.2%	56.0	57.2	2.1%	92.2	95.3	3.4%	5 to 40 Hours
Gas Steam	37.0	-	-	59.7	-	-	77.2	-	-	4 to 48 Hours
Unit Type				**Sig. Load Follow Cost ($/MW cap.)**			**Baseload VOM Cost ($/MWh)**			
				Baseline*	20% LODO**	%Change	Baseline*	20% LODO**	%Change	
Subcritical Coal				3.0	3.2	7.4%	2.70	2.61	-3%	
Supercritical Coal				2.0	2.6	26.9%	2.96	2.82	-5%	
Combined Cycle [GT+HRSG+ST]				0.7	0.7	0.0%	1.02	0.34	-67%	
Small Gas CT				0.6	0.7	2.0%	0.64	0.61	-4%	
Large Gas CT				1.6	1.7	1.2%	0.66	0.64	-4%	
Gas Steam				2.0	2.0	0.0%	0.92	0.92		

*Source - Kumar, Besuner, Agan, Lefton - http://www.nrel.gov/docs/fy12osti/55433.pdf

** - Changes in operating profiles to achieve 20% LODO were not included.

Cycling damage and costs accumulate and increase with increasing cycles, therefore the future costs are path dependent

e. g. increasing cycles in the future years will increase the future cycling costs

Table 1-5: Estimated Costs of Cycling and Other Data for Various Generation Types (20% HOBO)

Unit Type	Hot Start - C&M cost ($/MW cap.)			Warm Start - C&M cost ($/MW cap.)			Cold Start - C&M cost ($/MW cap.)			**Hot, Warm, Cold Start Definitions**
	Baseline*	20% HOBO**	%Change	Baseline*	20% HOBO**	%Change	Baseline*	20% HOBO**	%Change	Typical WS Hours Offline
Subcritical Coal	78.7	82.0	4.1%	114.2	118.0	3.3%	129.7	145.2	12.0%	8 to 48 Hours
Supercritical Coal	55.6	55.6	0.0%	65.9	65.9	0.0%	107.0	136.8	27.8%	24 to 120 Hours
Combined Cycle [GT+HRSG+ST]	36.0	41.3	14.7%	56.6	77.1	36.2%	81.3	91.1	12.1%	12 to 72 Hours
Small Gas CT	19.6	20.1	2.6%	24.7	25.4	2.7%	32.9	33.8	2.8%	4 to 5 Hours
Large Gas CT	32.9	33.7	2.2%	56.0	57.2	2.2%	92.2	95.1	3.1%	5 to 40 Hours
Gas Steam	37.0	-	-	59.7	-	-	77.2	-	-	4 to 48 Hours
Unit Type				**Sig. Load Follow Cost ($/MW cap.)**			**Baseload VOM Cost ($/MWh)**			
				Baseline*	20% HOBO**	%Change	Baseline*	20% HOBO**	%Change	
Subcritical Coal				3.0	3.5	16.0%	2.70	2.61	-3%	
Supercritical Coal				2.0	3.8	88.9%	2.96	2.84	-4%	
Combined Cycle [GT+HRSG+ST]				0.7	0.7	0.0%	1.02	0.39	-62%	
Small Gas CT				0.6	0.7	2.9%	0.64	0.62	-4%	
Large Gas CT				1.6	1.7	1.7%	0.66	0.64	-3%	
Gas Steam				2.0	2.0	0.0%	0.92	0.92		

*Source - Kumar, Besuner, Agan, Lefton - http://www.nrel.gov/docs/fy12osti/55433.pdf

** - Changes in operating profiles to achieve 20% HOBO were not included.

Cycling damage and costs accumulate and increase with increasing cycles, therefore the future costs are path dependent

e. g. increasing cycles in the future years will increase the future cycling costs

Table 1-6: Estimated Costs of Cycling and Other Data for Various Generation Types (20% HSBO)

Unit Type	Hot Start - C&M cost ($/MW cap.)			Warm Start - C&M cost ($/MW cap.)			Cold Start - C&M cost ($/MW cap.)			**Hot, Warm, Cold Start Definitions**
	Baseline*	20% HSBO**	%Change	Baseline*	20% HSBO**	%Change	Baseline*	20% HSBO**	%Change	Typical WS Hours Offline
Subcritical Coal	78.7	82.2	4.4%	114.2	118.7	3.9%	129.7	146.8	13.2%	8 to 48 Hours
Supercritical Coal	55.6	55.6	0.0%	65.9	65.9	0.0%	107.0	153.1	43.0%	24 to 120 Hours
Combined Cycle [GT+HRSG+ST]	36.0	43.9	21.9%	56.6	73.0	28.9%	81.3	85.7	5.4%	12 to 72 Hours
Small Gas CT	19.6	20.0	2.5%	24.7	25.3	2.5%	32.9	33.9	2.8%	4 to 5 Hours
Large Gas CT	32.9	33.5	1.6%	56.0	57.2	2.2%	92.2	95.1	3.1%	5 to 40 Hours
Gas Steam	37.0	-	-	59.7	-	-	77.2	-	-	4 to 48 Hours
Unit Type				**Sig. Load Follow Cost ($/MW cap.)**			**Baseload VOM Cost ($/MWh)**			
				Baseline*	20% HSBO**	%Change	Baseline*	20% HSBO**	%Change	
Subcritical Coal				3.0	3.2	7.1%	2.70	2.62	-3%	
Supercritical Coal				2.0	2.9	45.5%	2.96	2.82	-5%	
Combined Cycle [GT+HRSG+ST]				0.7	0.7	0.0%	1.02	0.35	-66%	
Small Gas CT				0.6	0.7	2.1%	0.64	0.61	-4%	
Large Gas CT				1.6	1.7	1.7%	0.66	0.64	-3%	
Gas Steam				2.0	2.0	0.0%	0.92	0.92		

*Source - Kumar, Besuner, Agan, Lefton - http://www.nrel.gov/docs/fy12osti/55433.pdf

** - Changes in operating profiles to achieve 20% HSBO were not included.

Cycling damage and costs accumulate and increase with increasing cycles, therefore the future costs are path dependent

e. g. increasing cycles in the future years will increase the future cycling costs

Table 1-7: Estimated Costs of Cycling and Other Data for Various Generation Types (30% LOBO)

Unit Type	Hot Start - C&M cost ($/MW cap.)			Warm Start - C&M cost ($/MW cap.)			Cold Start - C&M cost ($/MW cap.)			**Hot, Warm, Cold Start Definitions**
	Baseline*	30% LOBO**	%Change	Baseline*	30% LOBO**	%Change	Baseline*	30% LOBO**	%Change	Typical WS Hours Offline
Subcritical Coal	78.7	82.2	4.4%	114.2	122.4	7.1%	129.7	150.7	16.3%	8 to 48 Hours
Supercritical Coal	55.6	55.6	0.0%	65.9	73.6	11.7%	107.0	167.8	56.8%	24 to 120 Hours
Combined Cycle [GT+HRSG+ST]	36.0	45.1	25.1%	56.6	78.6	38.8%	81.3	86.9	6.8%	12 to 72 Hours
Small Gas CT	19.6	20.1	2.6%	24.7	25.3	2.4%	32.9	33.8	2.8%	4 to 5 Hours
Large Gas CT	32.9	33.5	1.6%	56.0	57.2	2.2%	92.2	95.1	3.1%	5 to 40 Hours
Gas Steam	37.0	-	-	59.7	-	-	77.2	-	-	4 to 48 Hours
Unit Type				**Sig. Load Follow Cost ($/MW cap.)**			**Baseload VOM Cost ($/MWh)**			
				Baseline*	30% LOBO**	%Change	Baseline*	30% LOBO**	%Change	
Subcritical Coal				3.0	3.5	16.0%	2.70	2.47	-9%	
Supercritical Coal				2.0	2.5	25.7%	2.96	2.30	-22%	
Combined Cycle [GT+HRSG+ST]				0.7	0.7	0.0%	1.02	0.36	-65%	
Small Gas CT				0.6	0.7	2.4%	0.64	0.62	-4%	
Large Gas CT				1.6	1.7	1.7%	0.66	0.64	-3%	
Gas Steam				2.0	2.0	0.0%	0.92	0.92		

*Source - Kumar, Besuner, Agan, Lefton - http://www.nrel.gov/docs/fy12osti/55433.pdf

** - Changes in operating profiles to achieve 30% LOBO were not included.

Cycling damage and costs accumulate and increase with increasing cycles, therefore the future costs are path dependent

e. g. increasing cycles in the future years will increase the future cycling costs

Table 1-8: Estimated Costs of Cycling and Other Data for Various Generation Types (30% LODO)

Unit Type	Hot Start - C&M cost ($/MW cap.)			Warm Start - C&M cost ($/MW cap.)			Cold Start - C&M cost ($/MW cap.)			Hot, Warm, Cold Start Definitions
	Baseline*	30% LODO**	%Change	Baseline*	30% LODO**	%Change	Baseline*	30% LODO**	%Change	Typical WS Hours Offline
Subcritical Coal	78.7	84.3	7.0%	114.2	128.8	12.8%	129.7	152.0	17.2%	8 to 48 Hours
Supercritical Coal	55.6	55.6	0.0%	65.9	71.7	8.9%	107.0	153.4	43.4%	24 to 120 Hours
Combined Cycle [GT+HRSG+ST]	36.0	45.7	27.0%	56.6	78.5	38.8%	81.3	84.1	3.4%	12 to 72 Hours
Small Gas CT	19.6	20.0	2.5%	24.7	25.3	2.5%	32.9	33.9	2.8%	4 to 5 Hours
Large Gas CT	32.9	33.5	1.6%	56.0	57.2	2.2%	92.2	95.1	3.1%	5 to 40 Hours
Gas Steam	37.0	-	-	59.7	-	-	77.2	-	-	4 to 48 Hours
Unit Type				**Sig. Load Follow Cost ($/MW cap.)**			**Baseload VOM Cost ($/MWh)**			
				Baseline*	30% LODO**	%Change	Baseline*	30% LODO**	%Change	
Subcritical Coal				3.0	3.4	14.3%	2.70	2.45	-9%	
Supercritical Coal				2.0	3.0	47.6%	2.96	2.60	-12%	
Combined Cycle [GT+HRSG+ST]				0.7	0.7	0.0%	1.02	0.33	-68%	
Small Gas CT				0.6	0.7	2.1%	0.64	0.61	-4%	
Large Gas CT				1.6	1.7	1.7%	0.66	0.64	-3%	
Gas Steam				2.0	2.0	0.0%	0.92	0.92		

*Source - Kumar, Besuner, Agan, Lefton - http://www.nrel.gov/docs/fy12osti/55433.pdf

** - Changes in operating profiles to achieve 30% LODO were not included.

Cycling damage and costs accumulate and increase with increasing cycles, therefore the future costs are path dependent

e. g. increasing cycles in the future years will increase the future cycling costs

Table 1-9: Estimated Costs of Cycling and Other Data for Various Generation Types (30% HOBO)

Unit Type	Hot Start - C&M cost ($/MW cap.)			Warm Start - C&M cost ($/MW cap.)			Cold Start - C&M cost ($/MW cap.)			**Hot, Warm, Cold Start Definitions**
	Baseline*	30% HOBO**	%Change	Baseline*	30% HOBO**	%Change	Baseline*	30% HOBO**	%Change	Typical WS Hours Offline
Subcritical Coal	78.7	84.3	7.0%	114.2	119.3	4.4%	129.7	144.0	11.1%	8 to 48 Hours
Supercritical Coal	55.6	55.6	0.0%	65.9	65.9	0.0%	107.0	136.2	27.3%	24 to 120 Hours
Combined Cycle [GT+HRSG+ST]	36.0	39.4	9.3%	56.6	76.1	34.4%	81.3	89.8	10.5%	12 to 72 Hours
Small Gas CT	19.6	20.3	3.9%	24.7	25.4	2.7%	32.9	33.7	2.4%	4 to 5 Hours
Large Gas CT	32.9	33.7	2.3%	56.0	57.2	2.2%	92.2	95.1	3.1%	5 to 40 Hours
Gas Steam	37.0	-	-	59.7	-	-	77.2	-	-	4 to 48 Hours
Unit Type				**Sig. Load Follow Cost ($/MW cap.)**			**Baseload VOM Cost ($/MWh)**			
				Baseline*	30% HOBO**	%Change	Baseline*	30% HOBO**	%Change	
Subcritical Coal				3.0	3.5	16.0%	2.70	2.57	-5%	
Supercritical Coal				2.0	4.0	100.0%	2.96	2.79	-6%	
Combined Cycle [GT+HRSG+ST]				0.7	0.7	0.0%	1.02	0.35	-66%	
Small Gas CT				0.6	0.7	2.8%	0.64	0.61	-4%	
Large Gas CT				1.6	1.7	2.0%	0.66	0.64	-3%	
Gas Steam				2.0	2.0	0.0%	0.92	0.92		

*Source - Kumar, Besuner, Agan, Lefton - http://www.nrel.gov/docs/fy12osti/55433.pdf

** - Changes in operating profiles to achieve 30% HOBO were not included.

Cycling damage and costs accumulate and increase with increasing cycles, therefore the future costs are path dependent

e. g. increasing cycles in the future years will increase the future cycling costs

Table 1-10: Estimated Costs of Cycling and Other Data for Various Generation Types (30% HSBO)

Unit Type	Hot Start - C&M cost ($/MW cap.)			Warm Start - C&M cost ($/MW cap.)			Cold Start - C&M cost ($/MW cap.)			**Hot, Warm, Cold Start Definitions**
	Baseline*	30% HSBO**	%Change	Baseline*	30% HSBO**	%Change	Baseline*	30% HSBO**	%Change	Typical WS Hours Offline
Subcritical Coal	78.7	83.2	5.7%	114.2	123.7	8.3%	129.7	149.4	15.2%	8 to 48 Hours
Supercritical Coal	55.6	55.6	0.0%	65.9	69.4	5.4%	107.0	154.3	44.2%	24 to 120 Hours
Combined Cycle [GT+HRSG+ST]	36.0	45.2	25.6%	56.6	75.0	32.6%	81.3	85.0	4.6%	12 to 72 Hours
Small Gas CT	19.6	20.1	2.8%	24.7	25.4	2.7%	32.9	33.6	2.1%	4 to 5 Hours
Large Gas CT	32.9	33.5	1.9%	56.0	57.2	2.2%	92.2	95.3	3.4%	5 to 40 Hours
Gas Steam	37.0	-	-	59.7	-	-	77.2	-	-	4 to 48 Hours
Unit Type				**Sig. Load Follow Cost ($/MW cap.)**			**Baseload VOM Cost ($/MWh)**			
				Baseline*	30% HSBO**	%Change	Baseline*	30% HSBO**	%Change	
Subcritical Coal				3.0	3.3	11.1%	2.70	2.58	-4%	
Supercritical Coal				2.0	3.0	50.0%	2.96	2.71	-8%	
Combined Cycle [GT+HRSG+ST]				0.7	0.7	0.0%	1.02	0.30	-70%	
Small Gas CT				0.6	0.7	3.2%	0.64	0.62	-4%	
Large Gas CT				1.6	1.7	1.9%	0.66	0.64	-3%	
Gas Steam				2.0	2.0	0.0%	0.92	0.92		

*Source - Kumar, Besuner, Agan, Lefton - http://www.nrel.gov/docs/fy12osti/55433.pdf

** - Changes in operating profiles to achieve 30% HSBO were not included.

Cycling damage and costs accumulate and increase with increasing cycles, therefore the future costs are path dependent

e. g. increasing cycles in the future years will increase the future cycling costs

The following figures represent the change in cycling damage and costs for each of the generation types when compared to the historical baseline costs. Again, the baseline costs are the lower bound wear and tear cycling costs determined and published by Intertek as part of the WWSIS Phase II study. The sample of units we analyzed did not represent a large number of gas steam units. Additionally the future scenarios forecast this generation type to be sparingly used. Therefore, we do not present any difference in costs for the different scenarios for the Gas Steam generation type.

Figure 1-11 shows the net impact of different cycle types – on/off as well as load follow cycling and the age related, creep damage represented as baseload damage. It is evident from this plot that units traditionally performing baseload operation, namely the coal fired units see a net change in cycling damage as they continue to operate in the same manner with small increase in on/off cycling. The majority of the increase in cycling damage on these units can in fact be related to the increased load follow cycling. However, typical load follow damage is usually a smaller percent of total damage. In general it is better to load follow a unit than to have an on/off cycle to prevent increased wear and tear costs. The biggest change in operating profile is seen on the combined cycle units, which perform a bulk of the on/off cycling in scenarios with increased renewable penetration.

It is interesting to note the more dramatic change in cycling impact on the supercritical coal units compared to the subcritical coal units. The primary reason for this is the increased load follows cycling performed by the supercritical units compared to the sub critical units. Figure 1-12 shows the change in load follow or ramping for the supercritical units compared to historical trends. While some of the units do not see major differences in the number of ramp/load cycles, there are several units that operate with at least 50% more load follow cycles than the historical trend. In fact almost 70% of the units in the 30% High Offshore Best Sites Onshore (30% HOBO) have greater than 50% ramp cycles compared to their operating history (this result also impacts the emissions analysis). A large change in the operation of these units is seen in the 30% HOBO scenario, with increased cycling operation, which results in a larger cost to cycle.

The results shown in Figure 1-11 through Figure 1-17 represent typical cycling cost values and spread that have been observed in our more than 20 years of cycling studies and estimated for the PRIS renewable integration scenarios.

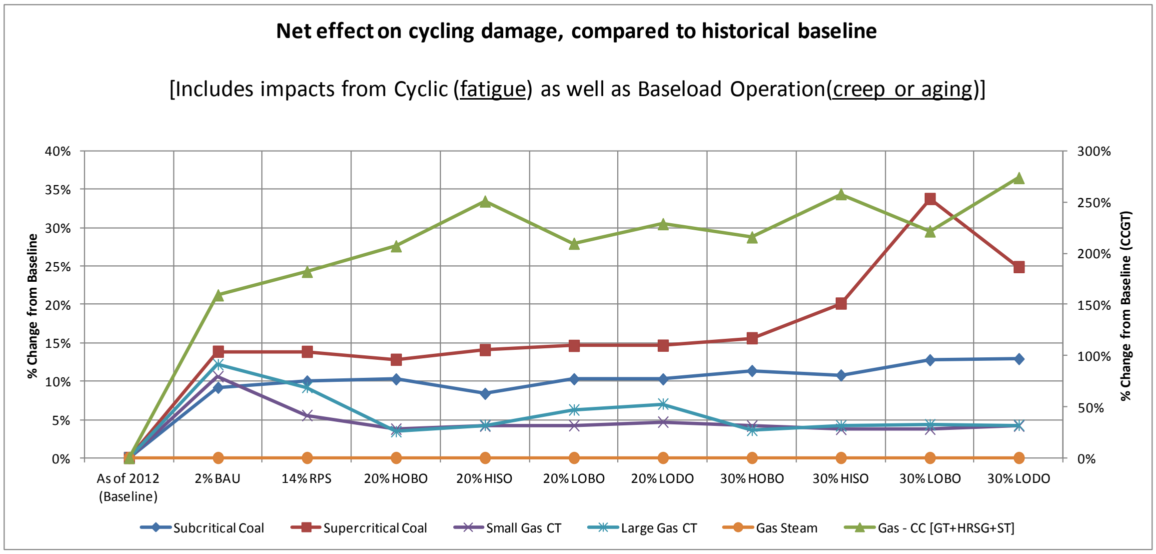

Figure 1-11: Net Impact on Costs in Different Scenarios

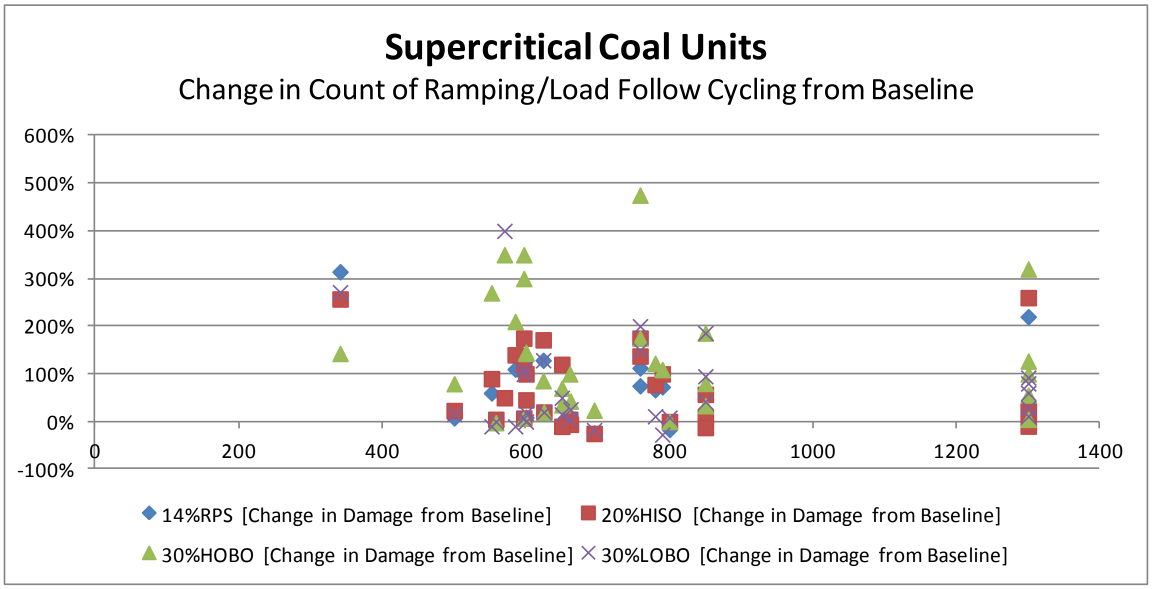

Figure 1-12: Supercritical Coal Units, Cycling Operation in Different Scenarios

Baseload VOM Cost

Figure 1-13 to Figure 1-17 show reductions in the baseload variable O&M costs ($/MWh) distribution for the power plant groups show reductions in the baseload variable O&M costs ($/MWh) distribution for the power plant groups. Non-cycling-related O&M costs include equipment damage due to base-load operation, chemicals, and other consumables used during operations. Supercritical units tend to operate as baseload and hence have the highest median baseload VOM cost. The CT units, both large frame and aero-derivative, typically run as intermediate or peaker units and are not operated baseload resulting in lower overall baseload VOM costs. Gas aero derivative CT units were found to have the least base load VOM cost, but these units typically operate in a cycling environment as peaking units (which have high “total” VOM Cost). Based on our methodology described in Figure 1-6, we attributed a significant portion of industry standard total VOM cost to cycling. As units change their mandate to increased cycling, baseload VOM costs tend to decrease while we see an increase in cycling related costs.

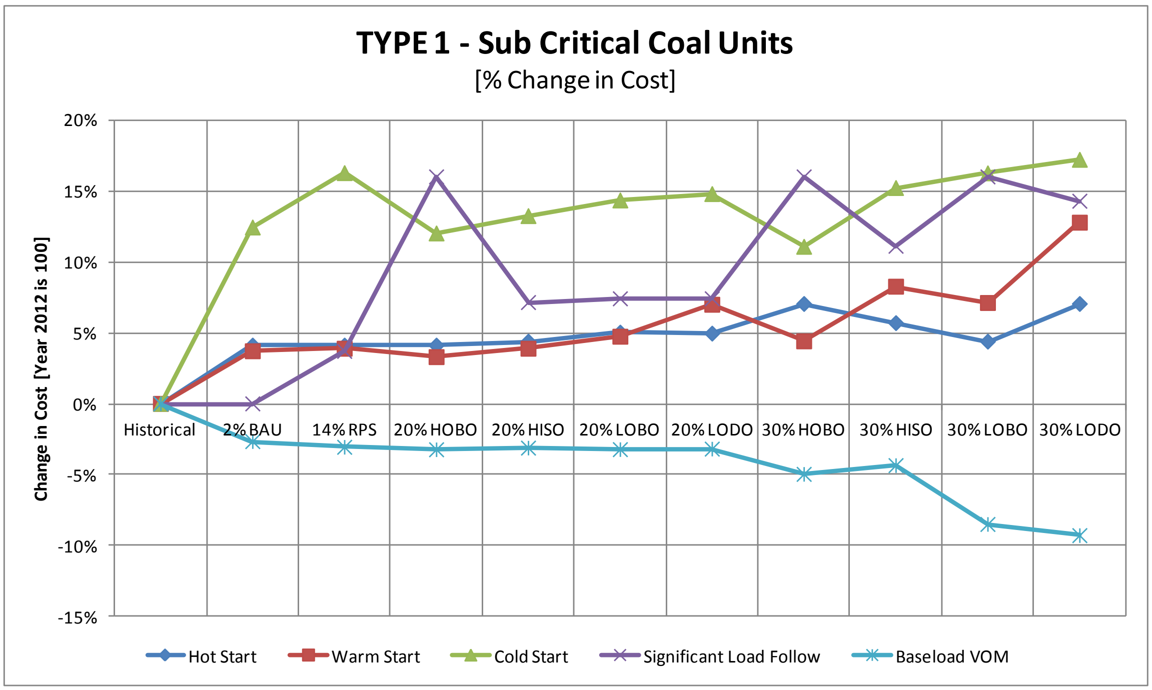

Figure 1-13: Subcritical Coal Units, Change in Number of Cycles in Different Scenarios

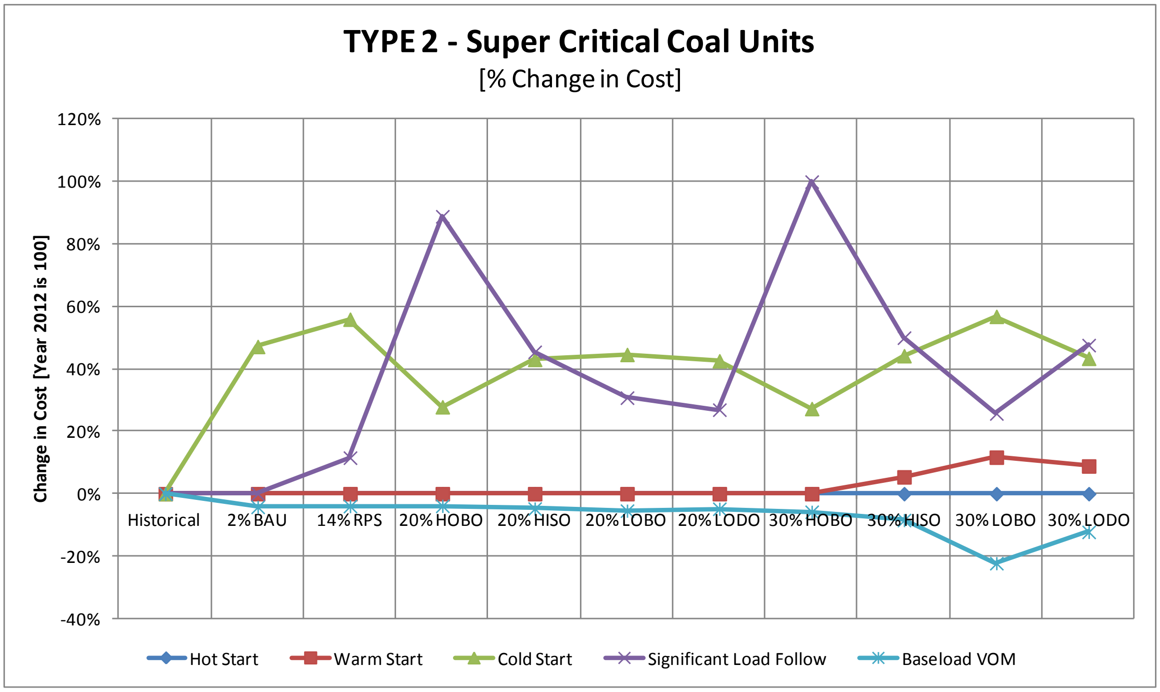

Figure 1-14: Supercritical Coal Units, Change in Number of Cycles in Different Scenarios

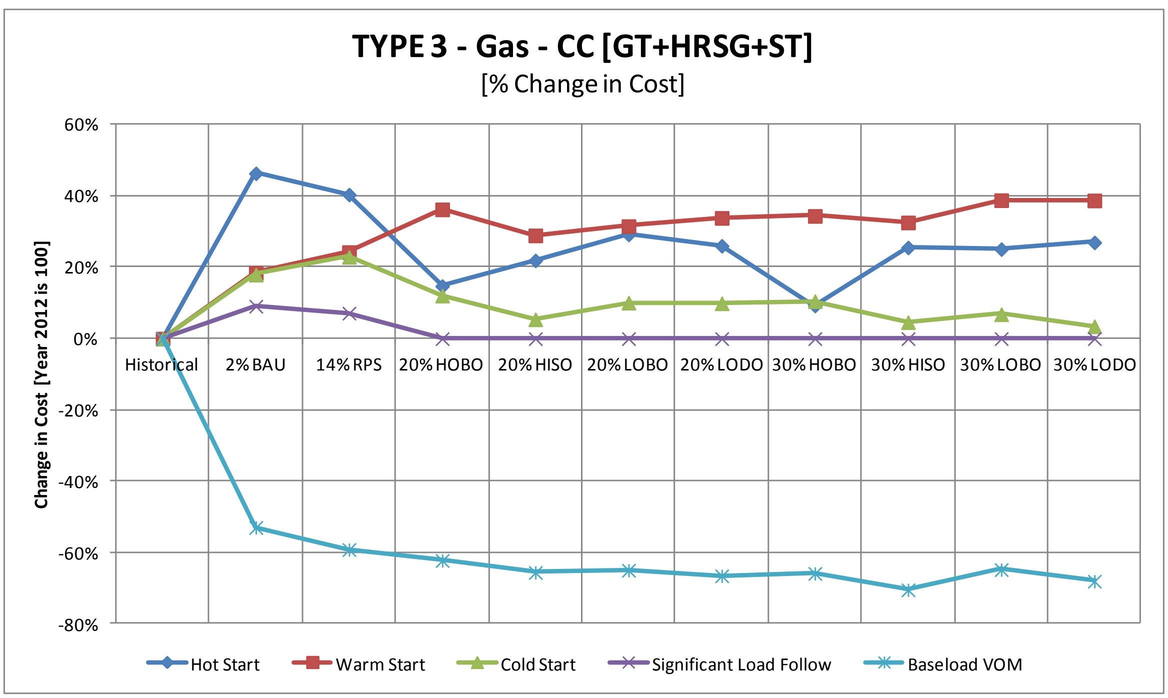

Figure 1-15: Combined Cycle Units, Change in Number of Cycles in Different Scenarios

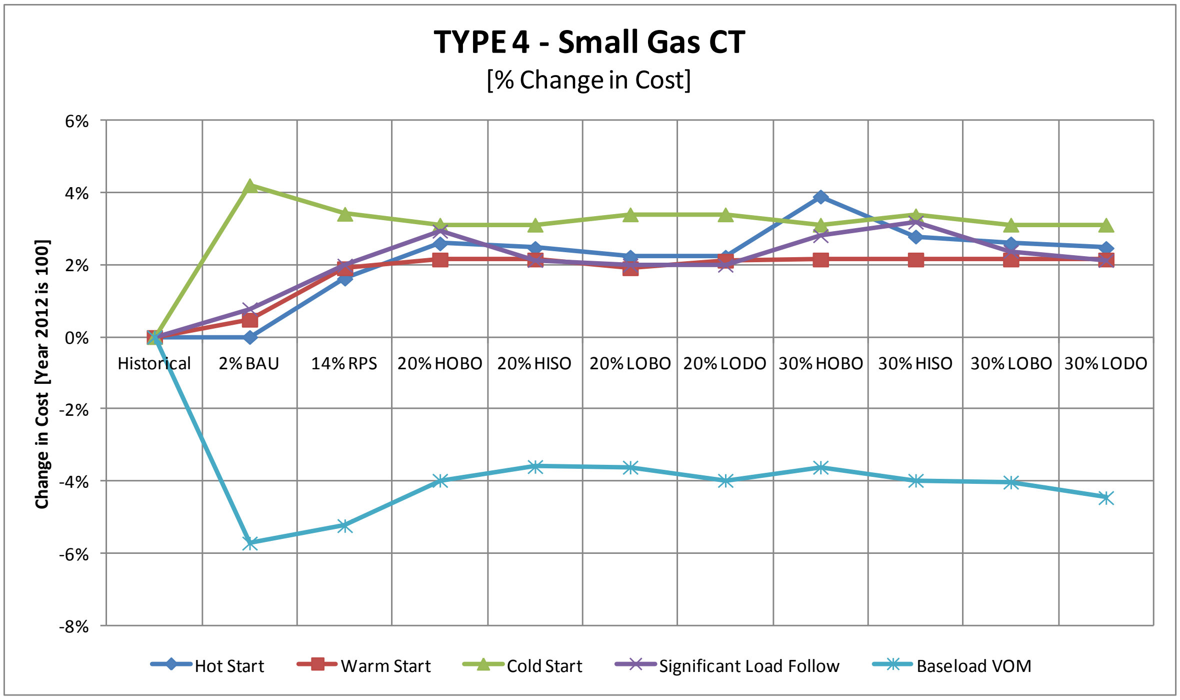

Figure 1-16: Small Gas CT Units, Change in Number of Cycles in Different Scenarios

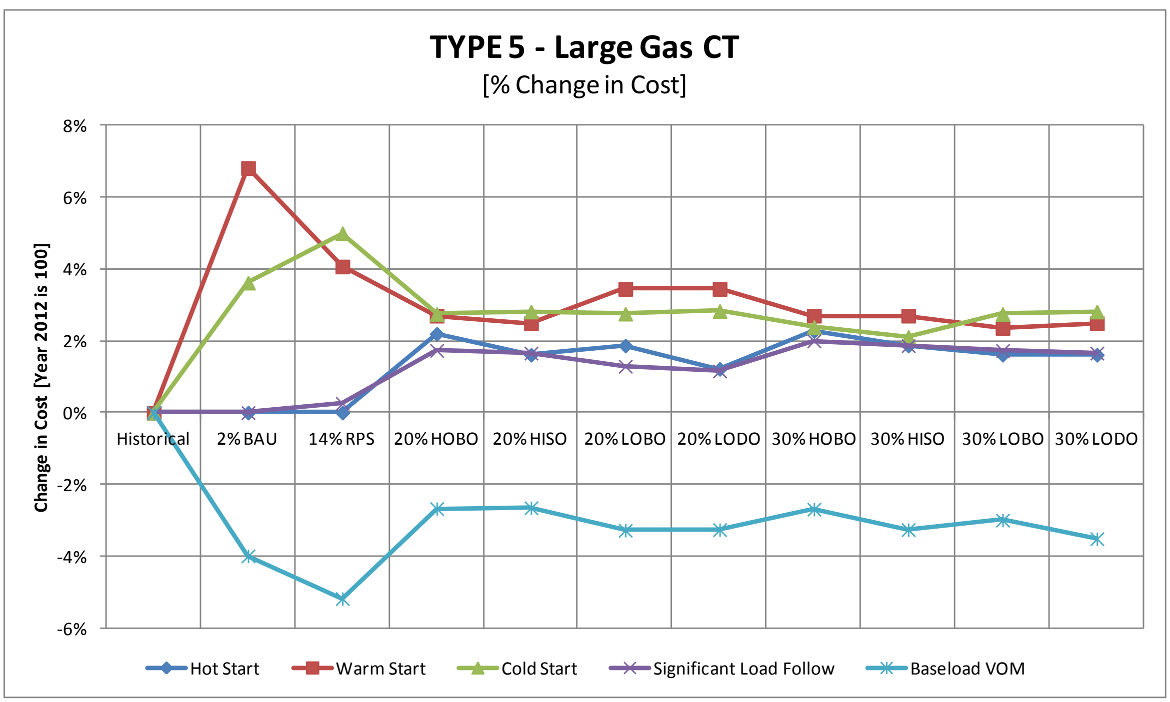

Figure 1-17: Small Gas CT Units, Change in Number of Cycles in Different Scenarios

Load Following Cost

The load following cost is presented as a $/MW capacity per load follows. Several units are simply incapable of ramping much faster than their typical ramp rates and hence applying a penalty for faster ramp rates has to be carefully included in production cost models. For example on the combined cycle units, the Gas turbines have traditionally compromised their fast-loading capabilities to accommodate the limitations of the HRSG and steam turbine. Table 1-11 shows the difference in startup ramp rates of the coal and combined cycle units when compared to historical actual averages. The combined cycle units have faster startup ramp rates, however the supercritical coal units are forecasted to have almost twice the ramp rate compared to their actual historical averages. This increased ramp rate impact is included in our analysis and is reflected in the cost to cycle these units.

Table 1-11: Comparing Scenario Ramp Rates to Historical

	MW/Min Ramp Rate								
	Historical			20% HISO			30%HISO		
	Hot Start	Warm Start	Cold Start	Hot Start	Warm Start	Cold Start	Hot Start	Warm Start	Cold Start
Subcritical Coal	1.24	1.16	1.22	1.47	1.51	1.55	1.51	1.57	1.55
Supercritical Coal	4.35	3.75	3.01	4.71	4.82	6.87	4.81	4.53	6.56
CCGT	2.73	2.89	2.65	4.84	4.96	4.11	4.85	5.02	4.29
x Times Historical Ramp Rates -->			Subcritical Coal	1.2	1.3	1.3	1.2	1.4	1.3
			Supercritical Coal	1.1	1.3	2.3	1.1	1.2	2.2
			CCGT	1.8	1.7	1.5	1.8	1.7	1.6

Typically larger units may have several significant load follows but only a few cycles that represent a minimum generation to maximum operating capacity type load follow cycle (deep load follow). Intertek AIM has seen this trend change of late with increased renewable generation on the grid. This trend is reflected in the scenario analysis performed in this study with supercritical coal units performing the bulk of the load follow operation.

Start-up Fuel and Other Start Costs

The Startup Cost of a power plant has other components other than Cycling Capital and Maintenance Cost. They are:

- Cost of startup auxiliary power
- Cost of startup fuel
- Cost of startup (Operations – chemicals, water, additive, etc.)

These costs have been included in the production cost simulations using the Ventyx – Velocity Suite database.

Figure 1-18 shows a comparison of the total fuel related costs and the wear and tear start/stop cycling costs for the different unit types for the 14% RPS scenario. As expected, the fuel costs dominate overall operating costs. However, taking into account the increased start/stop cycling from say the 14% RPS scenario to the 30% High Offshore Best Sites Onshore, the increase in plant maintenance cost can be significant.

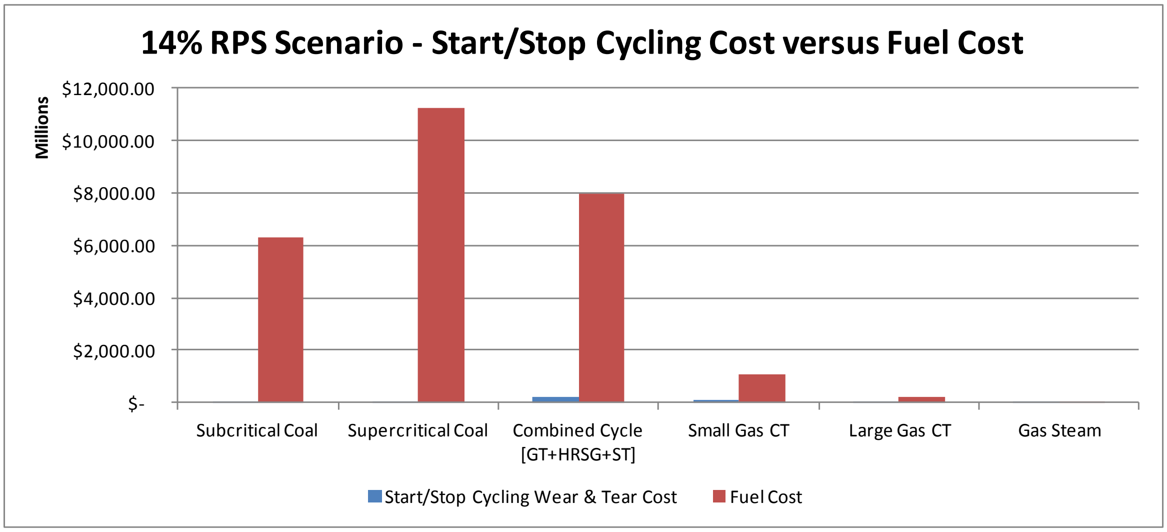

Figure 1-18: 14% RPS Scenario, Start/Stop Cycling Cost versus Fuel Related Cost

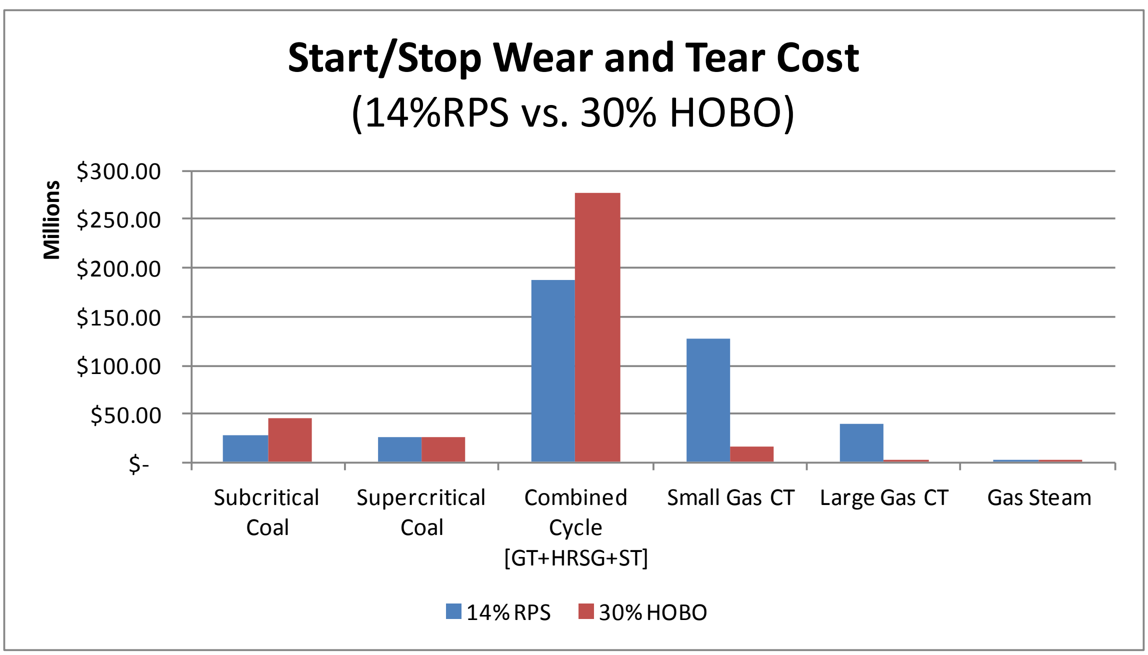

Figure 1-19: 14% RPS Scenario versus 30% HOBO Start/Stop Wear and Tear Cost

Figure 1-19 clearly shows that while as a percent of total operating costs, the wear and tear cycling costs may be low, but increased cycling can and will result in increased maintenance related costs on the fossil fleet. Moreover, if we add the cost of load follow or ramping cycling to the above start/stop cycling then the total wear and tear costs can be significant. Figure 1-20 shows the relative increase in total load follow related cycling costs for the supercritical coal units for two scenarios. Since, the supercritical coal units are forecast to provide a large amount of load follow cycles in the 30% scenario, this cost is in fact more than the start related costs. Energy markets should enable and create mechanisms for asset owners to recover these costs as the increased costs are not reflected in current budgets.

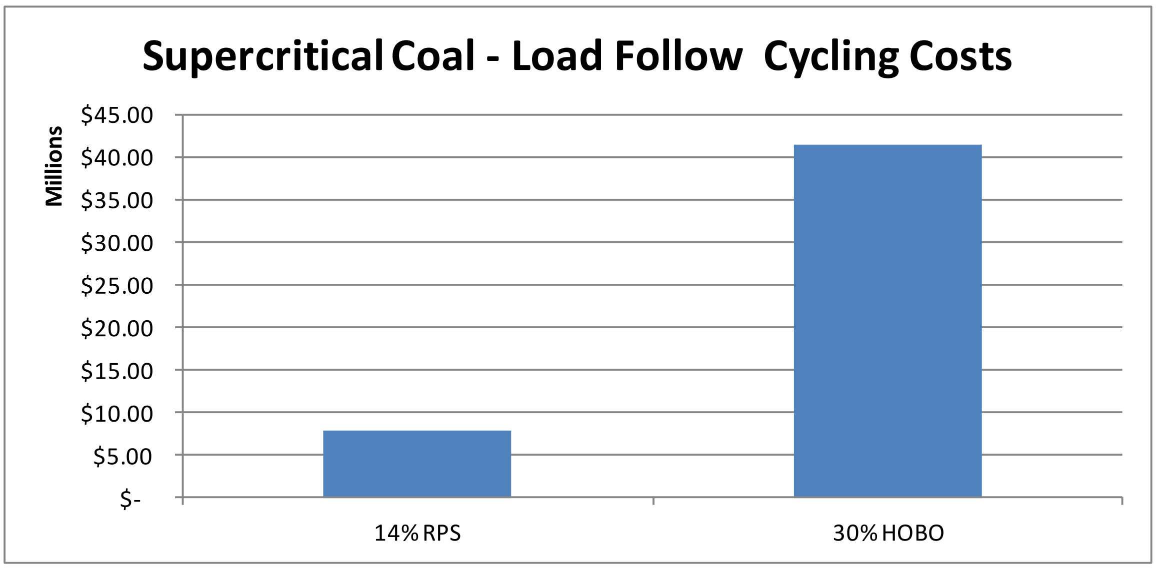

Figure 1-20: 14% RPS Scenario versus 30% HOBO Start/Stop Wear and Tear Cost

1.8 Impact of Cycling Duty on Variable O&M Costs

Figure 1-21 summarizes changes in cycling duty by study scenario for five types of PJM units. Combined cycle units experience the largest change in cycling duty as renewable penetration increases. Some increase in cycling is also evident for supercritical coal units in the 30% scenarios. Combined cycle units perform majority of the on/off cycling in the scenarios, with the coal units performing much of the load follow cycling.

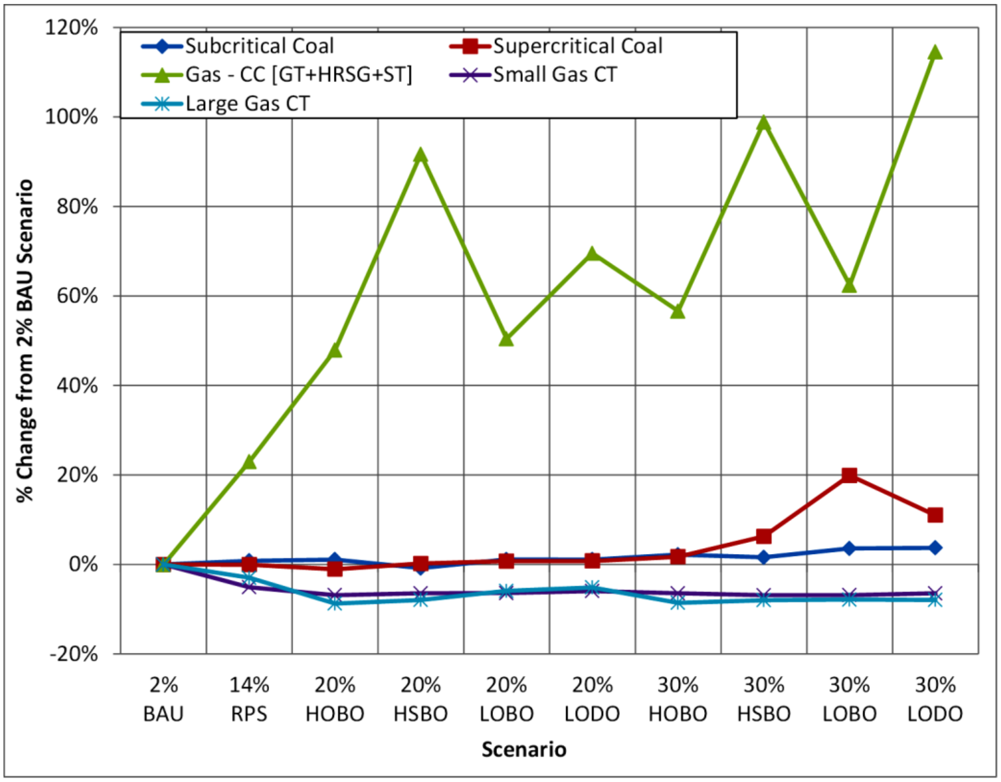

Figure 1-21: Net Effect on Cycling Damage Compared to 2% BAU Scenario

Table 1-12 shows cycling VOM costs in $/MWh (Cycling Costs = Start/Stop + Significant Load Follow). In almost all of the scenarios, the coal and combined cycle units perform increasing amounts of cycling; resulting in higher cycling related VOM cost and reduced baseload VOM cost, where:

$$\textit{Total VOM Cost} = \textit{Baseload VOM} + \textit{Cycling VOM}$$

Table 1-12: Variable O&M Costs ($/MWh) Due to Cycling Duty for Study Scenarios)

	2% BAU	14% RPS	20% HOBO	20% HSBO	20% LOBO	20% LODO	30% LOBO	30% HSBO	30% HOBO	30% LODO
Subcritical Coal	$1.14	$0.61	$1.78	$0.51	$0.69	$0.59	$1.09	$1.46	$2.52	$1.01
Supercritical Coal	$0.09	$0.11	$0.21	$0.15	$0.15	$0.14	$0.99	$0.31	$0.34	$0.46
Combined Cycle [GT+HRSG+ST]	$1.80	$2.69	$6.29	$5.19	$4.77	$4.68	$5.43	$7.55	$6.76	$5.81
Small Gas CT	$1.65	$1.74	$0.41	$0.52	$0.51	$0.60	$0.92	$0.87	$0.51	$0.82
Large Gas CT	$3.32	$3.41	$1.88	$2.68	$2.19	$2.42	$1.56	$1.52	$1.85	$2.02

1.9 Using Power Plant Cycling Costs in Simulation Models

Intertek AIM suggests that the cycling cost data in this report be used in PJM simulation models based on perception of the target unit's past cycling history and its cycling susceptibility. Intertek AIM suggests using its Loads Model[8] to more accurately account for power plant cycles (using the Rainflow counting method). This will allow Intertek AIM to provide the best suggestion for using these costs.

Still, for units with exceptionally high or low cycling susceptibility, even the use of the 75th and 25th percentile costs is not appropriate. For such atypical units, we recommend using Intertek AIM to produce appropriate Unit-specific cycling cost estimates.

A paper by J. Larson of Northern States Power (NSP)[9&10] addresses the concern about economic penalties of dispatching generation units using the wrong cycling cost data. This paper presents the results of a study quantifying the cost penalties of using incorrect cycling cost data in a Unit Commitment model (a model used to optimize dispatch schedules). The study used a typical five-weekday medium load period at NSP. The dispatch problem involved determining which small coal-fired units to run and cycle, and which purchases to buy. Figure 1-22 summarizes the results of this study by presenting the cost penalties to the system as a function of the degree of error in the startup cost estimate. The curve given in Figure 1-22 provides some very interesting insights. The first is that moderate errors in cycling cost information (e.g., plus or minus 50%) can be tolerated, as the cost penalties are relatively small. The second, more significant insight is that the penalties of using a cycling cost estimate that is much too low is much worse than for estimates that are much too high. Given the information on cycling costs, most utilities are using cycling costs in the range of 10% to 30% of what AIM has found to be the "true" cost of cycling. Thus, we believe most utilities may be in this high cost penalty regime.

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[8] The Loads Model includes the methodology and software Intertek AIM has been developing since the late 1980s to quantify cycling intensity from hourly generation and other data and background information, such as thermal signature and remaining useful life data. Loads Model software is simplified and converted to subroutines within the Cycling Advisor computer program (Production Cost Model), ensuring that our best cycling models are simulated.

[9] Cited in: "Operational aspects of generation cycling", IEEE Transactions on Power Systems (Volume: 5, Issue: 4, Page(s): 1194 - 1203) [Nov 1990].

[10] Technical Paper: "Economics of Cycling 101: What Do You Need To Know About Cycling Costs and Why?", by G. Paul Grimsrud and Steven A. Lefton.

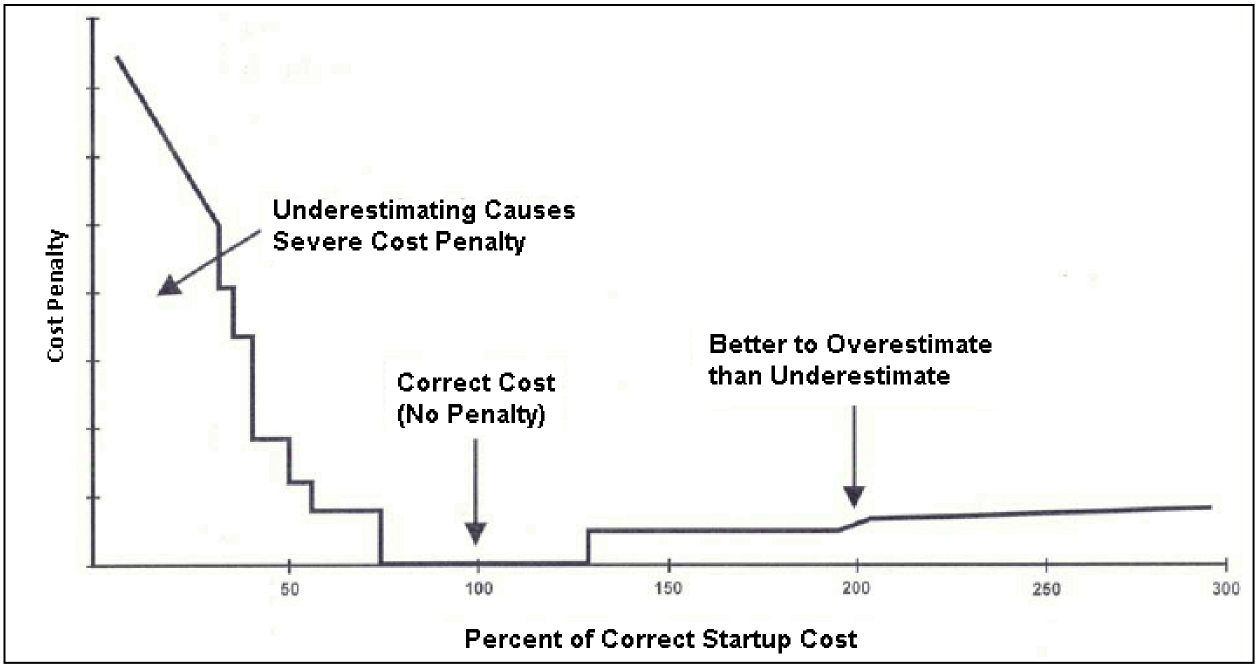

Figure 1-22: Calculated System Penalty for Using Incorrect Startup Cost

1.10 Components and Systems Affected by Cycling

Cycling operation increases the concern for creep-fatigue damage caused by thermal stresses, especially in units designed for baseload operation. The creep-fatigue is a dominant failure mode for damage and failures of many fossil plant components. A sample list of these is summarized in Table 1-13 to Table 1-18, which are lists of specific components in different technologies that are typically adversely affected by cycling and the primary damage mechanisms causing the damage. From this list several observations can be made. Creep-fatigue damage often locally occurs at stress concentration such as rotor grooves, header bore holes, ligaments, etc. involving large plastic strain. It may also involve elastic strain combined with stress relaxation like in combustion turbine blades. Creep-fatigue damage usually occurs because of thermal stress in constrained components during thermal transients. The constraints can be in internal cooling of components that incur rapid heating at the surface, like gas turbine blades, or internally in the case of heavy sections components like rotors, headers, drums, etc. where thermal gradients come about between the surface and the interior. The constraint can also be external such as in the case of joining thick to thin section or materials of different coefficients of expansion as in dissimilar metal welds. All of these stresses are thermally induced and occur in a relatively low number of cycles.

For gas turbines, the impacts of startup, shutdown, and part load cyclic operation on the component life, maintenance cost, emission compliance, unit reliability and availability are significant. Starts and shutdowns can induce excessive thermal fatigue damage, especially to the combustion system and hot gas path components, which lead to premature life and more forced outages. Fast cycling during load following can require transitions from one combustion mode to another which can reduce flame stability and increase combustion pressure dynamics. Both of these reduce reliability. Also, the high exhaust temperatures during transients mode transfers cause creep damage to expansion joints and of course the HRSG.

Table 1-13: Specific Components Typically Affected by Cycling (Small and Large Sub-Critical Coal)

Unit Type	Plant Equipment with Most Significant Adverse Impacts from Cycling	Primary Damage Mechanism	Backup Paper (if available)
Small and Large Sub-Critical Coal	Boiler Waterwalls	Fatigue Corrosion fatigue due to outages oxygen and high starts up oxygen Chemical deposits	The Cost of Cycling Coal Fired Power Plants, Coal Power Magazine, 2006 - S. Lefton, P. Besuner
	Boiler Superheaters	High temperature differential and hot spots from low steam flows during startup, long term overheating failures	
	Boiler Reheaters	High temperature differential and hot spots from low steam flows during startup, long term overheating failures, tube exfoliation damages IP turbines	
	Boiler Economizer	Temperature transient during startups	
	Boiler Headers	Fatigue due to temperature ranges and rates, thermal differentials tube to headers	
	LP Turbine	Blade erosion	
	Turbine shell and rotor clearances	Non uniform temperatures result in rotor bow and loss of desired clearance and possible rotor rubs with resulting steam seal damages	
	Feedwater Heaters	High ramp rates during starts, not designed for rapid thermal changes	
	Air Heaters	Cold end basket corrosion when at low loads and start up, acid dew point	
	Water/Chemistry Water Treatment Chemistry	Cycling results in peak demands on condensate supply and oxygen controls	
	Fuel System/ Pulverizers	Cycling of the mills occurs from even load following operation as iron wear rates increase from low coal flow during turn down to minimum	Power Magazine, August 2011, S Lefton & D. Hilleman, Making your Plant Ready for Cycling Operation. Also: Coal Power Mag, Improved Coal Fineness Improves Performance

Table 1-14: Specific Components Typically Affected by Cycling (Supercritical Coal, 600-700 MW)

Unit Type	Plant Equipment with Most Significant Adverse Impacts from Cycling	Primary Damage Mechanism	Backup Paper (if available)
Supercritical Coal, 600-700 MW	Same as subcritical coal except added temperatures in furnace tubing		
	Large supercritical furnace subject to uneven temperatures and distortion	Fatigue due to temperature ranges and rates, thermal differentials tube to headers	

Table 1-15: Specific Components Typically Affected by Cycling (Large Frame 7 or Frame 9 CT)

Unit Type	Plant Equipment with Most Significant Adverse Impacts from Cycling	Primary Damage Mechanism	Backup Paper (if available)
Large Frame 7 or Frame 9 CT	Compressor Blades	Erosion/corrosion fatigue. Thermal fatigue. Fatigue crack growth. Higher temperature gradients.	Erosion and Fatigue Behavior of Coated Titanium Alloys for Gas Turbine Compressors. Milton Levy, et. al. 1976.
	Turbine Nozzles/Vanes	Variable amplitude loading.	
	Turbine Buckets/Blades	Erosion/corrosion fatigue. Thermal fatigue. Fatigue crack growth.	Failure Analysis of Gas Turbine Blades. Microscopy Society of America. 2005. Rybnikov A.I., et al.
	Turbine Rotor	Variable amplitude loading. Erosion/corrosion fatigue. Thermal fatigue. Fatigue crack growth. Higher temperature gradients.	Potential Issues in Cycling of Advanced Power Plants, OMMI, April 2002. F. Starr
	Combustor Liner	Erosion/corrosion fatigue. Thermal fatigue. Creep-fatigue interaction	Combustion Turbine Hot Section Life Management, OMMI August 2002. M. Kemppainen, J. Scheibel, and R. Viswanathan.
	Fuel Injectors	Erosion fatigue. Thermal fatigue	Gas Turbine Handbook: Principles and Practice. Tony Giampalo 2003.

Table 1-16: Specific Components Typically Affected by Cycling (Aero-Derivative CT, LM 6000)

Unit Type	Plant Equipment with Most Significant Adverse Impacts from Cycling	Primary Damage Mechanism	Backup Paper (if available)
Aero-Derivative CT, LM 6000	Turbine Nozzles/Vanes	Variable amplitude loading. Erosion/corrosion fatigue. Thermal fatigue. Fatigue crack growth.	
	Turbine Buckets/Blades	Erosion/corrosion fatigue. Thermal fatigue. Fatigue crack growth.	
	Turbine Rotor	Variable amplitude loading. Erosion/corrosion fatigue. Thermal fatigue. Fatigue crack growth. Higher temperature gradients.	
	Combustor Liner	Erosion/corrosion fatigue. Thermal fatigue. Creep-fatigue interaction	

Table 1-17: Specific Components Typically Affected by Cycling (CCGT)

Unit Type	Plant Equipment with Most Significant Adverse Impacts from Cycling	Primary Damage Mechanism	Backup Paper (if available)
Combined Cycle Gas Turbine	HRSG Tube to Header Connections	Spatial (between tubes) differential temperatures High temporal temperature ramp rates & differential tube temperatures tube to tube. Thermal shock from un-drained Condensate during a startup or forced cooling purge cycles	
	Headers and drum	High ramp rates when cycling, thermal quench of bottom headers from un-drained condensate	Analysis Of Cycling Impacts On Combined Cycle, ASME Power Proceedings 2008 - S. Lefton, P. Grimsrud, P Besuner, D. Agan, J. Grover

Table 1-18: Specific Components Typically Affected by Cycling (CH, HRSG, and ST)

Unit Type	Plant Equipment with Most Significant Adverse Impacts from Cycling	Primary Damage Mechanism	Backup Paper (if available)
CT, HRSG, and ST	HRSG Tubes	High temporal temperature ramp rates and high stress from uneven flow rates, from laning of gas and low steam flows during cycling. Overheating (temperatures too high) in duct fired units Feedwater heater tube failures from thermal differentials in adjacent tubes during startups	Heat Recovery Steam Generators And Evaluating Future Costs Of Countermeasures To Reduce Impacts
	Condensate Piping, LP evaporator and Economizer/ Feedwater heater Tubing For CT (see Large Frame Unit below)	FAC Flow Assisted Corrosion in carbon steel tubes, headers and piping in low temperature sections including the LP or IP evaporator, economizers and feedwater heaters.	

1.11 Conclusions

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

- Figure 1-10 clearly shows the large spread of cycling start cost observed.
- Median Cold Start Cost for each of the generation types is about 1.5 to 3 times the Hot Start Capital and Maintenance Cost.
- The Small Gas CT units have almost the same relatively low costs for hot, warm, and cold starts. That is because in these designed-to-cycle units, every start is cold.
- Most coal units were designed for baseload operation and hence, on average are higher cycling cost units. This holds true for subcritical coal units in the various scenarios as well.
- There are some important economies of scale for large coal (and other fossil Units), that lower their costs. So the highest costs per MW capacity, as plotted, occur in some “abused” smaller coal units, especially for cold starts.
- Typically, large supercritical power plants have operated at baseload and not cycled historically. The forecast on the operating profile of these units in the various scenarios of the PJM PRIS study show a significant increase in load follow cycling on these units. Operating these units in cycling mode can result in unit trips and cycling failures. As a result of the false starts and trips, the real cost of cycling these units is significantly high. Moreover, these units cannot easily be brought online under these circumstances and such factors are not fully captured in this dataset.
- Combined cycle units are forecast to perform the bulk of the on/off cycling operation in the different scenarios. Older combined cycle units were designed for baseload operation and when operated in cycling mode can have higher cycling costs, which can be seen from the distribution of costs.
- Increasing ramp rates during load following is expensive. Still, the costs of increased ramp rate calculated for this report include only those fully attributed to start cycles.
    - The combined cycle units have a higher ramp rate cost, due to the operational constraints on the HRSG and ST. The large increase in cycle costs for the combined cycle estimated in the 14% and 30% HOBO scenario can be attributed to the faster cold start ramp rates. Higher ramp rates result in higher damage and this is most easily seen on the coal fired units. While not a linear relationship, additional research is required to determine further detail.
    - Combined cycle units have a limited load following range while maintaining emissions compliance.

- The higher operating and maintenance costs of supercritical units can be observed from the baseload VOM cost data.
- Small Gas CT units were found to have the least base load VOM cost, but these units typically operate in a cycling environment as peaking units (which have high "total" VOM Cost). Based on our methodology described in Figure 1-9, we attributed a significant portion of industry standard total VOM cost to cycling.
- 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.

1.12 Overview of the Method for Determining Bounds for Cycling Cost Estimates

Intertek AIM believes it is important to determine the bounds for the top-down cycling cost estimates. This is done by assessing the uncertainty in the cycling cost regression due to the combination of:

- Limited sample size
- Noise inherent in variations of annual cost and cycling characteristics
- Both standard and heuristic numerical procedures

Uncertainty is estimated in several steps:

- **Step 1** — Compute the best estimate of cycling cost (dC/de)[11] as the one that best fits annual cost data and "soft regression constraints." This answer must also satisfy any "hard" regression constraints imposed by data limitations and by Intertek AIM's engineering judgment (such as, on the "A coefficient", which represents that portion of costs that is independent of Unit loads). A hard constraint is one that must be satisfied unconditionally. A soft constraint need not be totally satisfied. Still, a penalty is imposed on the regression that increases according to how much the soft constraint is violated.
- **Step 2** — Rerun the analysis several times while forcing cycling cost (dC/de) "answers" that differ by various amounts from the best estimate of Step 1. The greater this forced deviation from the best-fit cycling cost, the worse the fit.

[11] Here "C" is wear and tear cost, including cycling cost, and "e" represents a specified cycle. A more complete description of APTECH's top down cycling cost equations will be included in the final report.

- **Step 3** — Study the negative impact of changing the answer on the regression fit and constraints in the following two ways:
  - o Visually and subjectively, comparing the fits "by eye"
  - o More objectively by comparing statistical measures of the "goodness" of both fit and ability to satisfy soft constraints
- **Step 4** — The bounds are set where the deviation from the best fit cannot be explained solely by randomness in the sample.

One Hard Constraint

As described above, for baseload units, typically a 50% to 75% range is imposed on the top-down analysis A coefficient to reflect the portion of wear and tear costs that have no relation to unit loading variations. This is a hard constraint. To implement it, the numerical analysis routine is prohibited from using values of A outside this range. The routine will arrive at its best regression solution by choosing any A value it wants to within the constraint, but it is forbidden to "wander" outside of the 50% to 75% range.

Two Soft Constraints

Soft constraints are more tolerant. They allow the numerical analysis routine to wander wherever it wants in search of a best regression fit. Soft constraints do not prohibit such wandering but severely "penalize" the routine if it wanders too far from the soft constraints.

In our first example of soft constraints, AIM uses a smoothing algorithm for many of its top-down regressions. The smoothing is done to cope with large year-to-year variations in maintenance, capital, and outage spending that may be the result of economic and political decisions, as opposed to how the unit is loaded. The smoothing algorithm uses one or more soft constraints. To implement these we defined "loss functions" (a term in the mathematics and statistics literature on regression) and place them into the function that the analysis routine is attempting to minimize. The loss function allows us to tolerate some small violation beyond a typical ±50% limit for smoothing annual cost data, if it results in a better regression fit.

The second example of a soft constraint is even more creative. After completing a top-down regression cycling cost estimate for one large unit, the client believed the estimate to be too low, as only past expenditures had been used as input and no accounting was made for large future capital costs that were certain to occur within the next 5 years. Certain boiler-tube sections were in need of replacement at a projected cost of $10 million (±30%). To account for this, a soft constraint on future capital spending was added to the regression model. The added loss function stayed at zero whenever the regression search predicted about $10 million capital spending over the next 5 years. This "future-spending loss function" was designed specifically to grow rapidly for models that differed by more than 30% from the predicted $10 million.

Even with this modification, however, the new cycling cost estimates increased by only about 15% over those from the original model. The reason was that the original model had "anticipated" some of these extraordinary future capital costs because it "noticed" annual past costs had been rapidly accelerating. Therefore, the aging part of the original regression model had done a good job modeling this unit's cost history.

Two measures are used in Step 3, Part 2, to calculate the deviations from perfect fit. The first is a measure of fit error alone. It is symbolized by "COV" because it is similar to, but considered more robust than, the standard statistical measure called "coefficient of variation." Specifically:

$$COV = \%100 * AAAFE / AAC$$

Where,

AAAFE = Average annual absolute fit error

AAC = Average annual cost

The second measure is a function developed by AIM that depends on the type and completeness of available data. We call this second measure equivalent COV or "ECOV." It depends on several measures of uncertainty including COV, maximum annual fit error, and the degree any soft constraints are violated by the regression result. The numerical value of ECOV is always expressed as a percentage and we define it such that ECOV is always larger than COV.

1.13 Overview of Cycling Analysis Approach

The Basic Premise

The underlying premise of the 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.

As detailed earlier in this section, AIM first screens total costs to eliminate only those costs that bear no relation to unit loading, like buildings and grounds expenses. Costs remaining after this initial screen are called "candidate" costs. These costs represent the total candidate annual capital, maintenance, and forced outage cost, independent of whether the cost was actually due to cycling or not.

Costs per Start

The final desired result is an estimate of the cycling cost elements combined to determine the effect of an additional equivalent start. 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. The present value of future wear-and-tear cycling costs for the plant equipment is the sum of two components: adding costs and hastening 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, hastening 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.

Determining bounds for the cycling cost estimates

AIM believes it is important to report the high and low bounds for the top-down cycling cost estimates. These are determined by assessing the uncertainty in the estimates of costs and the inputs to our damage models. Much of this uncertainty assessment is done heuristically, by inputting AIM's and the client's best, high, and low estimates of key input data into our cost calculations.

Heat Rate at Low Load and during Variable Load Operation

For most steam boiler fossil units and GTs, efficiency as measured by heat rate tests can degrade markedly due to cycling. Poor efficiency comes from low-load operations like load following and shutdowns. The cumulative effect of long-term usage can also increase the heat rate from causes like fouled heat exchangers and worn seals. This trend can often be shown by heat rate test data taken over time. However, heat rate tests do not tell nearly the whole story about the relation between efficiency and operation. The tests measure fuel burn efficiency only under ideal conditions reflecting a full constant load and, typically, a "tuned" and optimized mode of operation. This is why we make use of actual fuel burn data to estimate heat rate costs due to variable- and low-load operation.

Life Shortening Costs of Cycling

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

Overview of Cycling Costs and General Calculation Method

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., 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. These cycling cost numbers result from the combination of bottom-up and benchmarking analyses introduced in this section, as well as consideration of the unit operation and maintenance history, results of signature data analysis, and confidential cycling studies done by AIM for other utilities.

Intertek AIM has developed an equation that defines the total cost of cycling as the sum of the following distinct elements:

1. Increases in maintenance, operation (excluding fixed costs), and overhaul capital expenditures
2. Cost of heat rate changes due to low load and variable load operation
3. Cost of startup fuel, auxiliary power, chemicals, and extra manpower for startups
4. Cost of long-term heat rate increases (i.e., efficiency loss)
5. Long-term generation capacity cost increases due to unit life shortening

Additionally we capture the cost of replacement power (associated with EFOR), but has not been reported in our study for PJM.

The first cost element listed above, namely cycling-related maintenance, operation, and overhaul capital costs, is typically the largest cycling cost element for most fossil generating units. This is also true for GT cogeneration and combined cycle units.

Intertek AIM is bound by client requirements to report power plant cycling costs. As part of this project, Intertek AIM is reporting the above mentioned elements of costs separately.

Methodology: Determining Cycling Costs

Intertek AIM performs a comprehensive analysis of the plant operations and maintenance metrics, including a detailed audit of plant costs to determine the cost of cycling. As mentioned earlier the two key tasks in this analysis are the 'top-down' and 'bottom-up' steps. Typically, Intertek AIM performs the following tasks to determine its final cycling cost values:

- Review and Analysis of Plant Signature Data
- Engineering Assessment and Operations Review
- Survey of Selected Plant Personnel
- Damage Modeling
- Top-Down Cycling Cost Estimation
- Bottom-Up Cycling Cost Estimation
- Evaluate Unit Cycling Costs for Future Operations Scenarios

Review and Analysis of Plant Signature Data

Objectives: To determine the relative stresses and damage to key unit components using available signature data (i.e., real-time data points on pressures and temperatures at key points in each unit).

The following will be done for the selected unit for detailed cost of cycling analysis.

First, Intertek AIM develops a critical equipment list. The critical equipment list will include those components that are currently known to cause major outages and costs from the startup of a power plant and from similar units. Past reliability and outage data obtained from the unit under review will be analyzed. This analysis and review of major component outage cost contributors will assist in defining the critical cycling-related components. We will also make use of our past studies of cycling power plants to assist in identifying the critical equipment and the anticipated damage mechanisms.

For selected critical components, we will use available signature data, specifically, temperature and pressure transient data, to develop relative cycling damage. Examples of the analysis of plant hot start data are shown in Figure 1-23 and Figure 1-24 and the temperature change rates are shown in Figure 1-25. This is done by type of cycling (e.g., cold start, warm start, hot start, load swing to minimum load, unit trip, and normal shutdown). This data is shown in Table 1-20 and Table 1-21 and an example of the damage model input data by component is shown in Figure 1-26 and Figure 1-27. This analysis will be used as input to the damage modeling and the overall statistical/engineering analysis.

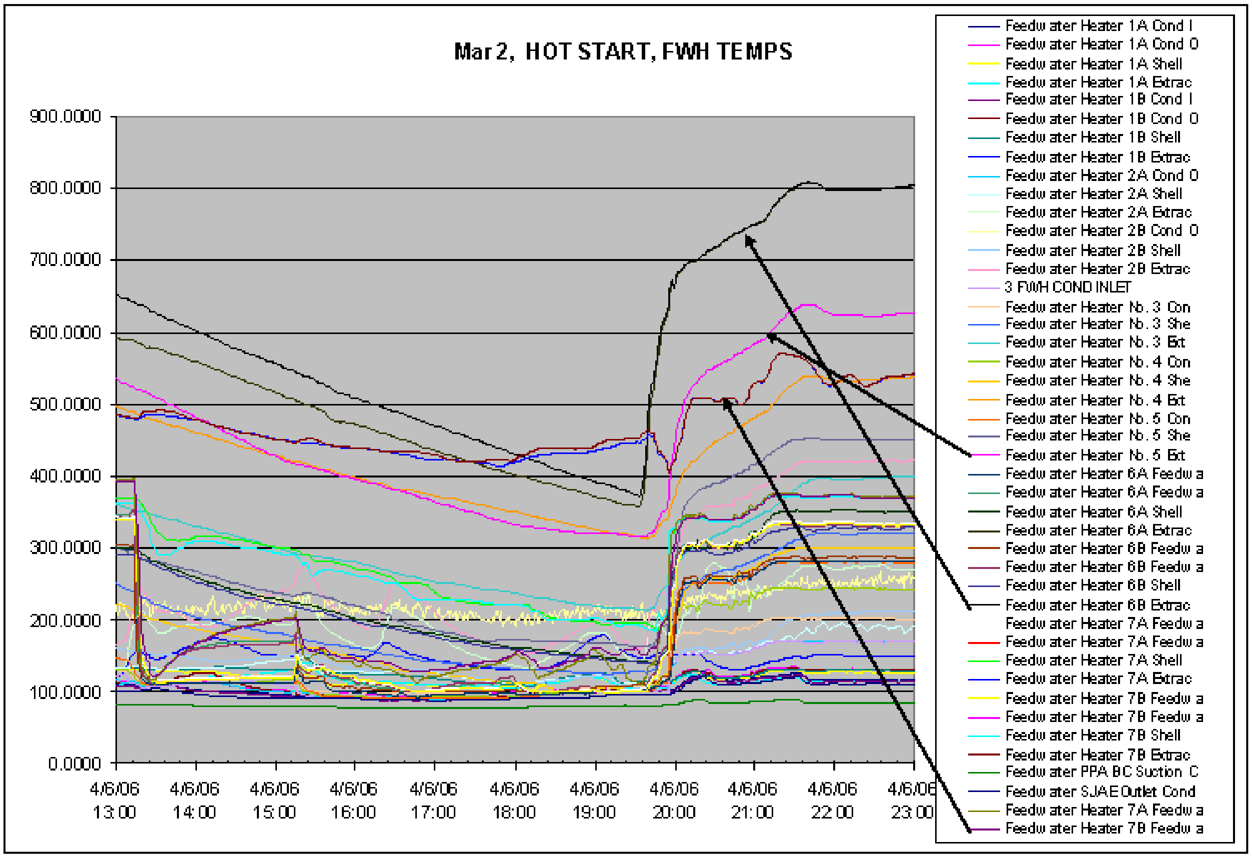

Figure 1-23: Example of Plant Hot Start Data

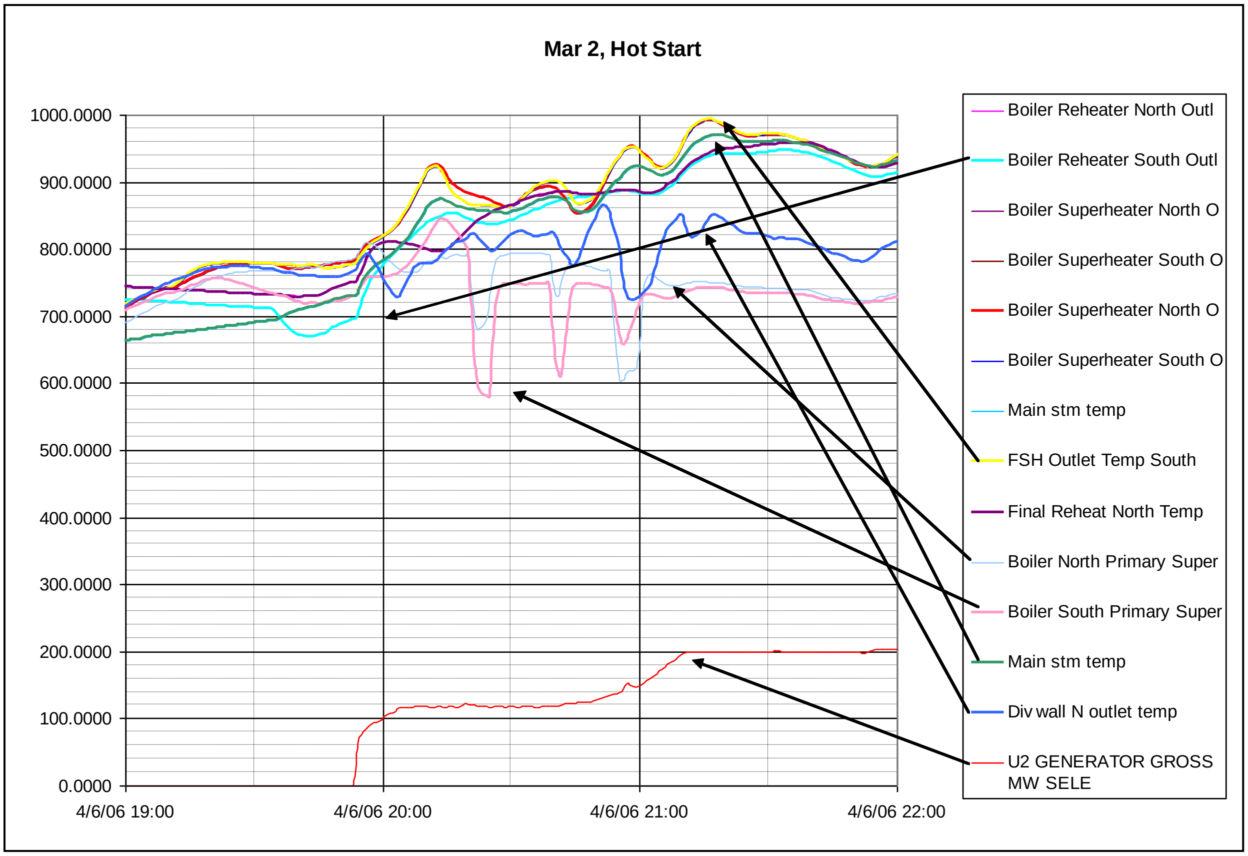

Figure 1-24: Another example of Plant Hot Start Data

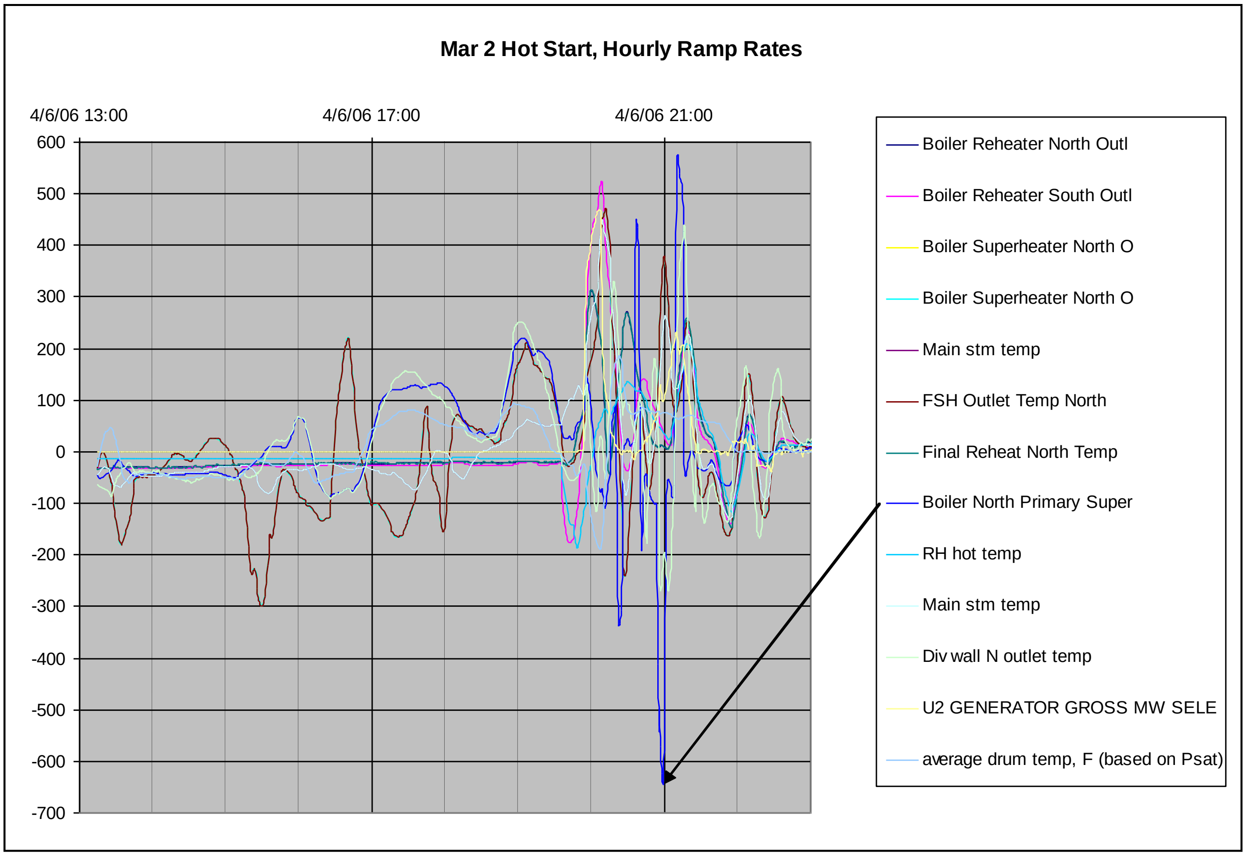

Figure 1-25: Example of Hourly Temperature Changes Corresponding to Figure 1-23

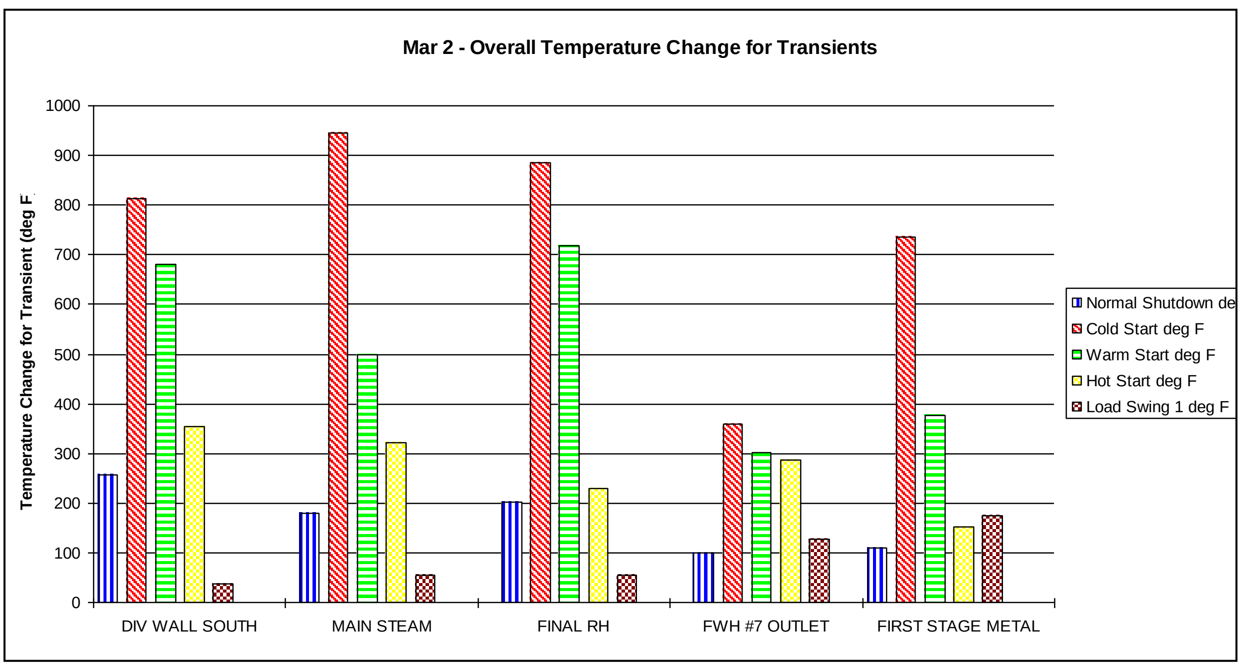

Figure 1-26: Example of Maximum Temperature Change for Components

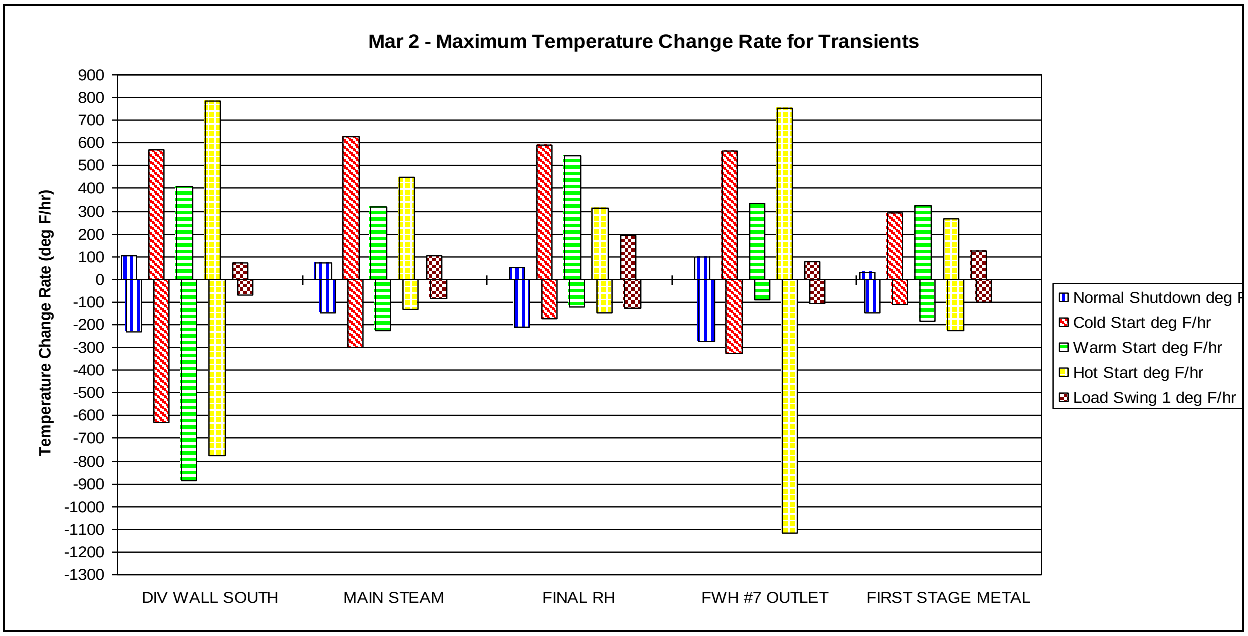

Figure 1-27: Example of Overall Temperature Change for Components

Engineering Assessment and Operations Review

Objectives: To assess cycling damage based on equipment outage and inspection data that is independent from top-down analysis. To provide insights on which component and operation practices contribute most to cycling costs.

Intertek AIM investigates and assesses the major causes of failures at the selected units, and determines whether they are wholly or partially caused by cycling or low load operation. Specific activities in this task will include:

1. Design review of current unit design including equipment lists, piping and instrument diagrams, and startup-related equipment limitations.
2. Review major failure modes of critical boiler, turbine, generator, fans, pumps, feedwater heater, and condenser equipment that we know are cycling-related.
3. Review all work orders to include 95% of all the work orders for the last 7 years and assign a percent cycling to these work orders and total by major component and system.
4. Review the history of the cycling-related failures with other similar units "in the industry" we have studied.

5. Review of plant operational procedures from the minute-by-minute analysis of the plant signature data, written procedures, and evaluate options for improved operational and maintenance procedures for cycling operations.
6. Provide a preliminary list of improvement options soon after the completion of the field trip.
7. Provide a list of concerns and recommendations.
8. Review unit condition assessment and remaining useful life data.

Survey of Selected Plant Personnel

Objectives: To provide a check on cost of cycling estimates using a survey of the selected power plant unit experts in the field and obtain plant personnel input on cycling-related problems.

Intertek AIM has found that a good way of checking the cost of cycling estimates made by regression analysis is to do a qualitative survey of experts, including primarily plant personnel, who are very familiar with the operating histories and problems at the plants. An interview process Intertek AIM has developed for other cost of cycling studies will be adapted and customized for use in this project. The interviews are designed to utilize the knowledge of at least six key selected plant personnel to discuss past cycling costs and to foresee what future effects different unit operation modes (e.g., types and intensities of cycling) will have on their units [example for a coal unit]. Ideally, the six people should consist of the following:

- Plant Management
- Operations
- General Maintenance
- Turbine Maintenance Expert
- Boiler Maintenance Expert
- Plant Chemistry Expert

Damage Modeling

Objectives: To adapt Intertek AIM's unit-wide damage model to develop unit damage histories for the selected units.

Intertek AIM adapts its existing damage models for assessing the damage accumulation and reliability impact on the critical equipment. The damage model starts with a previously-developed Intertek AIM power plant damage model, called the "Loads Model," which is based on hourly MW generation. We request all hourly data for the unit to be studied. We have proven methods to extrapolate loads model results backward in time using annual generation, service hour, and start data.

The damage model calculates total unit baseload (creep) and cyclic (fatigue) damage. Therefore, the model has the ability to apportion and discriminate between baseload and cyclic damage. It also can incorporate the effects of poor fuel quality (e.g., increased erosion), which is not expected to have an impact on costs for oil and gas-fired units. The model calculates damage under cyclic and steady loads of any magnitude that interact with each other in a nonlinear fashion. It accounts for any combination of load peaks and valleys, times at load, ramp rates (load changes with time), and differences among hot, warm, and cold starts. Thus, it handles all sorts of cycling in combination with normal, derated, or uprated steady loads.

Top-Down Cycling Cost Estimation

Objectives: To develop best estimates and upper and lower bounds of the largest cycling cost components, which are capital and maintenance costs, and outage costs.

We use Intertek AIM's proprietary regression techniques, along with the output of previous tasks (e.g., annual damage accumulation histories), to develop cycling cost estimates for what is typically the largest cycling cost components — namely, increased capital and maintenance spending, increased outages leading to more expensive replacement power, and increased heat rates due to low and variable load operation. This analysis will result in best estimates, and upper and lower bounds for these cost components, and with plots of the regression fit model against historical records of actual cost/outage data.

Bottom-Up Cycling Cost Estimation

Objective: To allocate the total unit cycling costs by primary unit systems and components (e.g., boiler, turbine, generator, piping, etc.).

Intertek AIM collects, and reviews detailed accounting data on specific capital and non-routine maintenance expenditures. This may include the accounting of major work orders that relate to projects to repair or mitigate adverse cycling impacts. We estimate the percent of each expenditure that is caused by cycling. We use this accounting to estimate the breakdown of unit-wide cycling costs into major systems and components, as shown in Figure 1-28.

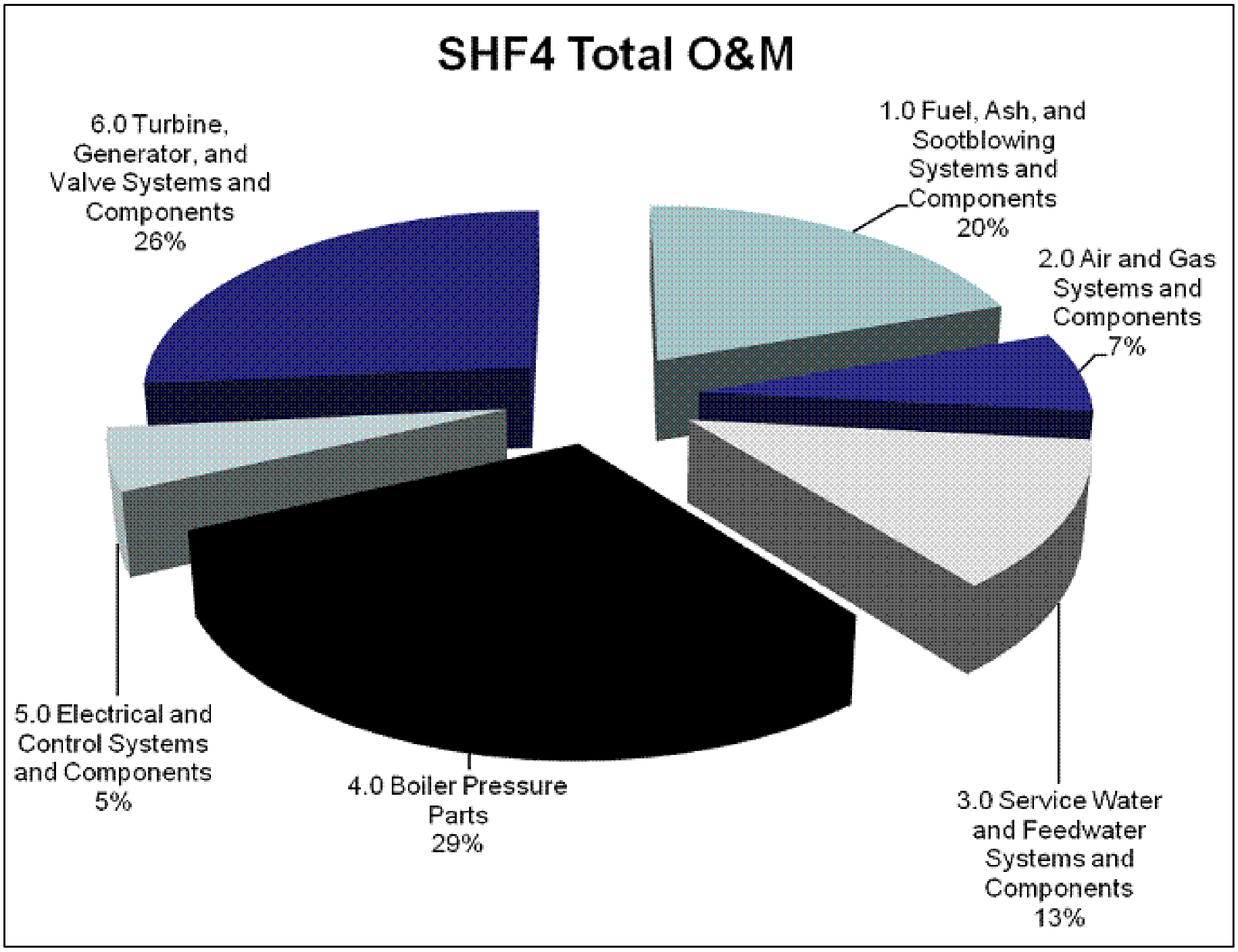

Figure 1-28: Work Orders Broken Out by Component and System for Cycling Costs

We also use our industry databases, both NERC-GADS data and data from similar units Intertek AIM has already studied in detail, to broaden and bolster the bottom-up accounting of outages and costs for the selected unit. We collect and summarize subsystem level cost data from our previous and current cycling studies and collect industry wide outage, maintenance, and other data collected by NERC-GADS for similar units. We use the GADS "pedigree" file and detailed descriptions of plant equipment of the unit under review to determine both similarities and differences from the subject unit.

Evaluate Unit Cycling Costs for Future Operations Scenarios

Objective: To project the reliability and capital/maintenance cost impacts of future operations scenarios.

Intertek AIM develops a set of graphs that show how the reliability and capital/maintenance costs of the selected unit will vary in the future under the different operation scenarios identified by the subject unit. An example of such a graph is shown in Figure 1-29. It resulted from an actual Cycling Model for large units. We computed cycling damage for the four plotted future scenarios and used these to model past and future costs.

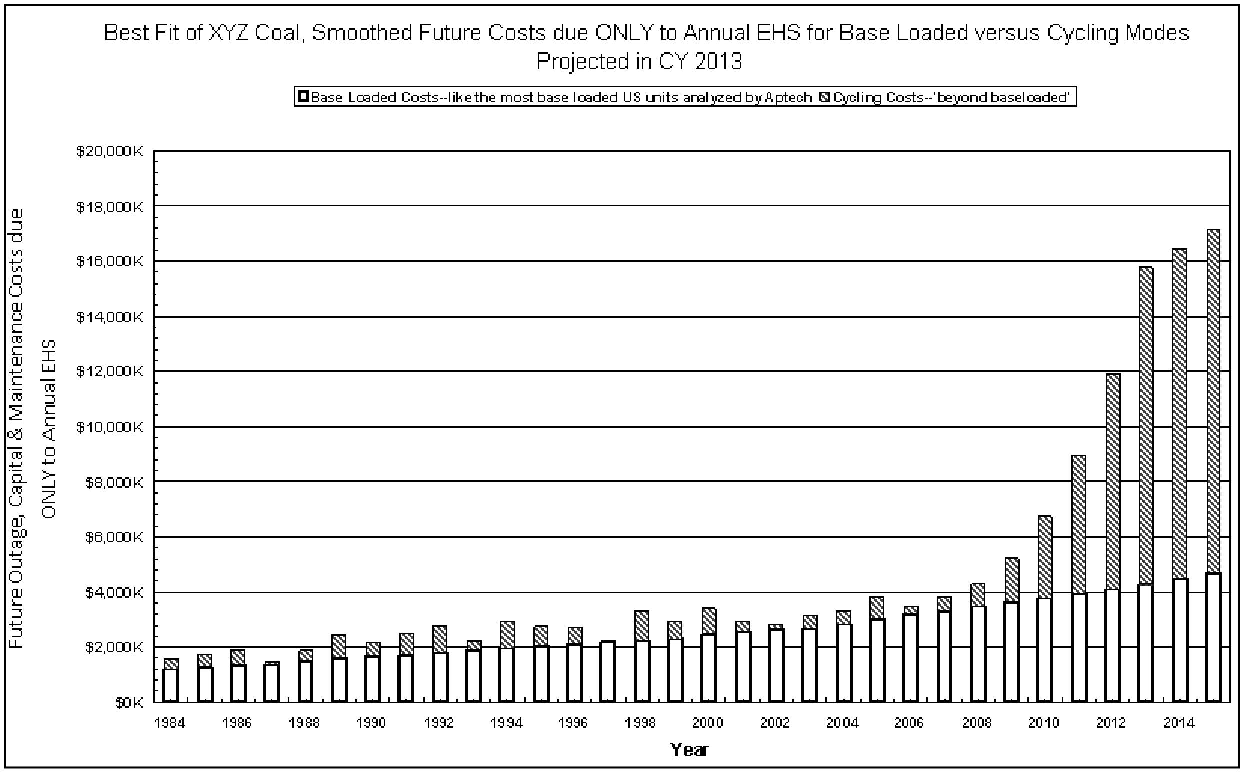

Figure 1-29: Best Estimate of XYZ Cycling Maintenance and Capital Costs

Note: Based on Large Power Plant No Cycling Countermeasures and Increases Due to Increased Load Cycling Only

Results from the Cost of Cycling Study

The total cost of cycling is broken down into nine different elements (E1 through E9). The composite of these nine cost elements (E1 through E9) are totaled to determine the cost of each type of cycling (hot starts, warm starts, cold starts, and significant load follows). For example, for a combined cycle unit, the hot, warm, and cold starts are defined by the metal temperature of the heat recovery steam generator (HRSG), gas turbine, and steam turbine when the start is initiated. A significant load follow is defined as a load change (typically 20% of maximum continuous rating or more) that results in a substantial amount of wear-and-tear damage as defined by Intertek AIM's Loads Model (very small MW load changes are not considered). Table 1-19 shown below provides an example break down of cycling costs for a steam turbine.

Table 1-19: Cost Elements for Hot Start/Shutdown cycles at Steam Generator

1 Steam Turbine Hot Starts for 2002	Baseline Data ($/ cycle) [1]			Baseline Data ($/MW-hr) [2]		
	Best Estimate	Low	High	Best Estimate	Low	High
E1: Cost of operation – Includes operator non-fixed labor, general engineering and management cost (including planning and dispatch); excludes fixed labor		$ 1,600			$0.00094	
E2: Cost of maintenance - includes maintenance and overhaul maintenance expenditures for boiler, turbine, generator, air quality control systems and balance of plant key components		$ 5,000			$ 0.0029	
E3: Cost of capital maintenance - includes overhaul capital maintenance expenditures for boiler, turbine, generator, air quality control systems and balance of plant key components		$ 3,000			$ 0.0018	
E4: Cost of forced outage and derate effects, including forced outage time, replacement energy, and capacity.		$ 18,000			$ 0.0106	
E5: Cost of long-term heat rate change due to cycling wear and tear [3]		$ -			$ -	
E6: Cost of heat rate change due to low load and variable load operation (process related)		$ -			$ -	
E7: Cost of startup auxiliary power		$ -				
E8: Cost of startup fuel		$ 40,000			$ 0.0235	
E9: Cost of startup (Operations – chemicals, water, additive, etc.)		$ -				
Total incremental cost of cycling (sum of E1 through E9)		$ 71,000			$ 0.0416	

[1] Cost data refer to top down results for CY2002, including fatigue-creep interaction effects, does not include adjustment for signature data analyses
[2] based on all analyzed starts and net MWh during CY2002
[3] Over the last 5 years, maintenance and other activities have prevented discernible heat rate increase solely due to cycling
Note: Total best estimate = sum of individual ones; but this is not true of high and low totals

Top-Down Statistical Regression Method

Intertek AIM has found that reasonably accurate estimates of total unit cycling costs can be derived using a regression analysis of historical unit damage with historical cost and equivalent forced outages, along with component-specific data that indicate the breakdown of cycling costs among various cycle types (e.g., hot, warm, and cold starts, load follows). This section briefly describes the various aspects of Intertek AIM's top-down cycling cost methodology.

Damage Modeling

Model Description

One way to model cycling-related damage for any component in a fossil power plant is by direct damage modeling. This type of modeling could combine physical measurements, taken while the component is on-line (e.g., temperature, strain, and heat flux), with state-of-the-art stress analyses and damage algorithms to produce a detailed estimate of the amount of damage suffered by the particular component.

However, this type of analysis would require substantial time, data collection, and funding. To limit the cost of analyzing all critical components in the unit, a general damage resources model, developed by Intertek AIM, is employed. This model is intended to provide information on the cycling-related damage for the entire unit. It is founded on physical models and uses plant temperature and other signature data to provide cross validation with MW changes, but requires only hourly MW "loads" data to estimate damage. (Note: In this section of the report, the term "loads" refers to the MW output of the unit, not forces, moments, or temperatures.) Relying solely on hourly MW unit load data is an inherent advantage due to the fact that these types of data are more readily available. In addition, hourly MW data provide an accurate history of past unit operations.

The general damage model is based on an Intertek AIM proprietary computer code that has been tested and employed on over 300 previous fossil plant cycling studies. The model is very flexible, adaptable, and general. It accounts for creep damage, fatigue damage, erosion, corrosion, and all other types of damage that are known to occur in fossil power plants.

The damage model has been calibrated several different ways. The two most important methods are:

- Predicting later cycling costs from earlier ones. Benchmarking studies have been performed which ask the top-down model to predict later costs using only the early portion of cost data from the units' database. Comparison of the predicted costs with the actual past costs has helped to calibrate and improve the cycling damage and cost models. The model has been calibrated to accurately reflect past costs and should accurately predict future costs.

- Comparing cycling cost estimates with “bottom-up” results. A bottom-up approach to calculating cycling costs requires a very detailed and comprehensive accounting. This accounting would include a diary of all past equipment failures and all maintenance activities. From this data and an understanding of the active damage mechanisms for each piece of equipment and their root causes, the costs of cycling as a function of cycling events can be developed for each piece of equipment. The cycling-related cost divided by the number of cycles (as defined later) results in a cost per cycle. This type of analysis has been performed for many different unit types at different power companies. Reasonably close agreement between the bottom-up and top-down estimates serves to confirm the models.

Damage Model Results and Operational Histories

The Loads Model is an MW-output-based damage model that counts all fatigue cycles, creep, and fatigue-creep interaction. The damage accumulation rates computed by Intertek AIM's Loads Model are related to the fatigue damage emanating from an idealized gentle load transient known as an equivalent hot start (EHS). The model takes hourly MW data as input to calculate the EHS. Table 1-20 gives the resulting quarterly damage estimates in equivalent hot starts (EHS) per quarter.

Using the hourly MW data the damage model is used to determine the relative damage of “typical” hot, warm, and cold start cycles of Example Units 5, 6, 7, 8, and 9 in relation to our normalized damage parameter, EHS. These are shown in Table 1-21, along with the typical MW ramp rates used for all five units. The relative damage numbers for hot, warm, and cold start cycles are among the highest we’ve seen for coal-fired steam units. Table 1-22 shows the computed relative damage rates of load follow cycles.

Table 1-20: Loads Model Quarterly Data for Example Unit

Quarter	EHSs	Op Day	EHSs	Per Day	Hot op days	ws	cs	if	orat	pd	md	starts
1Q82	48.4	81.8	0.592	7.2	3	4	0	26	26.96	90	1	7
2Q82	29.4	77.2	0.489	12.8	2	4	1	31	8.21	91	1	7
3Q82	24.7	71.2	0.445	13.8	0	2	3	32	5.67	92	7	5
4Q82	30	44.2	0.482	44.8	1	1	3	16	11.29	92	3	5
1Q83	30.7	33.9	0.529	56.1	1	0	5	5	8.08	90	0	6
2Q83	30.8	44.2	0.55	44.8	2	1	4	29	11.25	91	2	7
3Q83	36.6	82.5	0.53	9.5	2	3	1	11	29.46	92	0	6
4Q83	26.3	86.5	0.493	5.5	0	0	1	2	27.46	92	0	1
1Q84	43.9	59.8	0.517	31.2	4	5	3	21	9.38	91	0	12
2Q84	24.1	17.8	0.542	73.2	2	0	2	3	4.21	91	0	4
3Q84	42.3	72.4	0.547	19.6	1	2	4	33	13.5	92	0	7
4Q84	28.1	75.6	0.529	15.4	0	2	1	6	22.12	92	1	3
1Q85	40	82.1	0.525	7.9	2	4	1	12	21.25	90	0	7
2Q85	36.6	87.1	0.515	3.9	2	3	0	5	31.88	91	0	5
3Q85	24.5	84.2	0.496	5.8	1	2	1	20	3.75	92	2	4
4Q85	27.6	76	0.487	14	0	1	2	10	12.29	92	2	3
1Q86	27.2	86.7	0.474	3.3	1	0	1	5	27.04	90	0	2
2Q86	19.1	78.6	0.459	12.4	0	1	0	9	14.5	91	0	1
3Q86	8.5	5.4	0.464	84.6	0	1	1	1	2.83	92	2	2
4Q86	34.1	66.4	0.467	18.6	3	2	0	6	40.88	92	7	5
1Q87	46.3	69.3	0.477	17.7	2	1	4	9	37.25	90	3	7
2Q87	53	75.8	0.488	12.2	5	6	1	17	23.62	91	3	12
4Q87	38.7	83.8	0.487	8.2	1	2	1	20	31.83	92	0	4
1Q88	29.9	81.9	0.481	8.1	0	1	1	17	47.12	91	1	2
2Q88	36.9	86.2	0.478	4.8	1	3	0	21	42.12	91	0	4
3Q88	28.9	81.5	0.473	10.5	1	0	1	27	39.29	92	0	2
4Q88	44.6	74.6	0.477	15.4	2	3	3	10	44.75	92	2	8
1Q89	27.2	49.2	0.479	40.8	0	0	3	4	25.88	90	0	3
2Q89	27	33.6	0.485	57.4	2	4	3	23	8.29	91	0	9
3Q89	31.5	57	0.487	32	2	1	3	36	11.62	92	3	6
4Q89	60	68.9	0.499	20.1	4	4	3	32	25.58	92	3	11
1Q90	56.1	71.8	0.508	17.2	7	1	3	65	15	90	1	11
2Q90	28	81.1	0.502	2.9	1	2	0	21	17.33	91	7	3

Table 1-20 (Continued)

Quarter	EHSs	op days	EHSs	Per day	Hot op days	ws	cs	lf	orat	pd	md	starts
3Q90	33.8	85.5	0.499	6.5	0	2	1	8	44.75	92	0	3
4Q90	24	88.5	0.49	2.5	0	0	0	10	25.96	92	1	0
1Q91	21.9	56.4	0.488	33.6	1	1	2	30	0	90	0	4
2Q91	27.8	79.5	0.484	9.5	2	1	1	39	0	91	2	4
3Q91	20.6	58.9	0.481	31.1	0	2	1	26	0	92	2	3
4Q91	31.5	61.5	0.482	30.5	1	2	1	36	1.46	92	0	4
1Q92	32.1	77.5	0.48	13.5	0	1	2	38	3.33	91	0	3
2Q92	26.3	83.3	0.475	6.7	1	2	1	30	1.25	91	1	4
3Q92	28.9	81.5	0.472	10.5	0	3	1	50	0.12	92	0	4
4Q92	26.5	83.9	0.467	8.1	1	0	1	27	0.79	92	0	2
1Q93	31.5	74.3	0.466	15.7	0	2	3	32	0.25	90	0	5
2Q93	37.5	75.8	0.467	15.2	3	3	1	20	0.42	91	0	7
3Q93	22.1	89.8	0.461	2.2	0	1	0	23	0.25	92	0	1
4Q93	11.2	42.9	0.458	49.1	0	0	0	1	0.17	92	0	0
1Q94	39.1	64	0.461	26	4	3	2	22	0.88	90	0	9
2Q94	32.8	83.1	0.46	7.9	2	4	0	40	0.08	91	0	6
3Q94	23.9	89.5	0.455	2.5	0	2	0	38	0.21	92	0	2
4Q94	25.4	87.2	0.451	4.8	1	3	0	9	0.08	92	0	4
1Q95	26.3	72.1	0.449	17.9	0	2	2	1	0.33	90	0	4
2Q95	22.1	83.8	0.445	7.2	1	1	1	3	0.29	91	0	3
3Q95	21.4	89.8	0.44	2.2	0	2	0	4	0.46	92	0	2
4Q95	30.6	80.2	0.439	11.8	0	2	2	6	3.58	92	0	4
1Q96	18.9	66.9	0.437	24.1	0	2	0	7	0.71	91	0	2
2Q96	26.3	50.3	0.438	40.7	1	3	1	23	0.12	91	0	5
3Q96	29	80.6	0.436	11.4	0	5	0	40	0.08	92	0	5
4Q96	34.2	80.8	0.436	11.2	1	2	1	25	21.62	92	0	4
1Q97	26	80.9	0.434	9.1	1	1	2	39	0.62	90	0	4
2Q97	30.9	77	0.433	14	0	4	1	29	0.04	91	0	5
3Q97	30.6	83.1	0.432	7.9	0	4	0	21	0.08	92	1	4
4Q97	23.8	87.1	0.429	4.9	0	3	0	28	0.38	92	0	3
1Q98	22.1	83.3	0.426	4.7	0	0	1	39	0.62	90	2	1
2Q98	28.4	90	0.424	1	0	1	0	50	2.08	91	0	1
3Q98	31.2	82.1	0.423	9.9	2	3	1	15	0	92	0	6

Table 1-20 (Continued)

Quarter	EHSs	Op days	EHSs	Per day	Hot op days	ws	cs	lf	orat	pd	md	starts
4Q98	20.8	82.1	0.42	9.9	0	0	1	6	0.92	92	0	1
1Q99	26	62.5	0.42	27.5	0	0	3	9	0.46	90	0	3
2Q99	23	81.5	0.418	9.5	0	2	1	7	1.17	91	0	3
3Q99	23.7	88.7	0.416	2.3	0	2	0	5	0.75	92	1	2
4Q99	29	83.7	0.415	8.3	1	4	0	4	0	92	0	5
1Q00	19.2	83.7	0.412	6.3	0	1	1	7	0.17	91	1	2
2Q00	19.4	26.9	0.413	64.1	0	0	4	4	0.42	91	0	4
3Q00	31	82.9	0.413	9.1	2	0	1	4	1	92	0	3
4Q00	24.6	86.2	0.411	4.8	0	2	1	2	0.54	92	1	3
1Q01	25.8	77.5	0.41	11.5	1	3	1	2	0.21	90	1	5
2Q01	24.8	80	0.408	11	0	3	1	9	0.29	91	0	4
3Q01	20.1	86.7	0.405	5.3	0	2	0	5	0.21	92	0	2
4Q01	17.8	67.7	0.404	24.3	0	2	1	4	0.04	92	0	3
1Q02	26.2	80	0.403	10	0	3	2	2	1.83	90	0	5
2Q02	23.4	77.5	0.401	13.5	1	1	2	5	0	91	0	4
3Q02	31.6	85.3	0.401	6.7	1	4	0	7	0.92	92	0	5
4Q02	19.6	84.1	0.399	7.9	0	0	2	5	0	92	0	2
1Q03	21.1	85.6	0.397	4.4	0	1	1	3	0	90	0	2
2Q03	25.7	77.6	0.396	13.4	1	1	1	0	0.04	91	0	3
3Q03	18.8	83	0.394	9	0	1	1	3	0	92	0	2
4Q03	25.9	76.3	0.393	15.7	0	2	1	4	0	92	0	3
1Q04	21.8	40	0.394	51	0	0	4	3	0	91	0	4
2Q04	24.8	85.5	0.393	5.5	0	3	0	3	0.58	91	0	3
3Q04	29.3	62	0.393	30	0	1	4	6	0.25	92	0	5
4Q04	18.7	63.4	0.392	28.6	0	1	2	3	1.83	92	0	3
1Q05	14	47.6	0.392	42.4	0	1	1	1	1.83	90	0	2
2Q05	23.8	68	0.391	23	0	1	3	35	1.92	91	0	4
3Q05	27	83.9	0.39	8.1	0	2	1	46	0	92	0	3
4Q05	16.1	85.5	0.388	6.5	0	0	1	17	0.17	92	0	1
1Q06	21.8	87.4	0.386	2.6	0	1	0	13	0.04	90	0	1
2Q06	18.6	86.7	0.384	4.3	0	0	1	27	0.04	91	0	1
3Q06	17.3	89.9	0.382	2.1	0	1	0	32	0	92	0	1
4Q06	15.9	92	0.379	0	0	0	0	11	0.04	92	0	0
1Q07	23.1	73	0.379	17	2	2	1	6	0	90	0	5

Statistical Regression on Damage Costs

Intertek AIM has developed an equation that defines the total cost-of-cycling as the sum of the following five distinct elements:

Increases in maintenance, operation (excluding fixed costs), and overhaul capital expenditures:

- Increased time-averaged replacement energy and capacity cost due to increased equivalent forced outage rates (EFOR)
- Increase in the cost of heat rate changes due to low load and variable load operation
- Increase in the cost of startup fuel, auxiliary power, chemicals, and extra manpower for startups
- Cost of long-term heat rate increases (i.e., efficiency loss)

Intertek AIM's top-down statistical method uses a mathematical regression technique to calculate the present value wear-and-tear cost of the next additional cycle. The basis for the top-down regression analysis is made by examining calendar time trends in maintenance (including capital) and EFOR-related costs, and obtaining an independent quantitative relation between cycling and these time-varying costs for the plant.

Table 1-21: Damage Statistics for Typical Starts

	Hot Starts				Warm Starts				Cold Starts			
Unit	Number in Database	Range (%GDC)	Ramp Rate (%/hr.)	Damage (%EHS)	Number in Database	Range (%GDC)	Ramp Rate (%/hr.)	Damage (%EHS)	Number in Database	Range (%GDC)	Ramp Rate (%/hr.)	Damage (%EHS)
5	82	105	53	216	152	102	52	311	110	96	48	450
6	88	103	52	206	182	101	51	292	133	98	48	469
7	101	107	50	200	170	100	54	311	111	94	50	467
8	95	107	48	197	191	102	52	309	109	96	50	478
9	72	103	53	211	157	102	51	299	118	96	50	480

Table 1-22: Load Following Damage

Unit	Number in Database	Eff. Avg. Min. Load	Eff. Avg. Drop (% GDC)	Eff. Avg. Rate (%GDC/hr)	Damage (%EHS)
ki5	2075	126	29	33	5
ki6	1735	127	29	34	5
ki7	2382	128	28	35	5
ki8	2118	126	29	34	5
ki9	2164	127	28	34	5

Note: average damage from load-following drops of more than 15% gross capacity (based on hourly gross MW data)

2 Power Plant Cycling Emissions Analysis

2.1 Effects of Power Plant Cycling on Air Emissions

While renewable energy resources provide emissions-free electricity, their variability requires the coal and gas fired generation resources to adapt with less efficient ramping and cycling operations, which in turn impacts their environmental emissions, potentially reducing some of the benefit from the renewable generation. This study examines the changes in emissions amounts and rates for the PJM portfolio considering various future scenarios which differ in the level of cycling operations of the units.

Heat rates and therefore emissions from fossil-fueled generators are impacted during cycling and ramping/load cycling and differ compared to steady-state operation. We analyzed this cycling impact on the annual emissions (lbs/year) and emissions rates in pounds per million Btu of fuel burned (lbs/MMBtu) of NOx and SO2 for gas and coal fired steam power plants, gas turbine and gas turbine combined cycle plants. Traditional production-cost models estimate emissions based on steady-state operation of the plant and do not take into account on-off cycling or load ramping.

This research on the effects of cycling on emissions shows the additional impact of cycling operation on the emissions as the proportion of renewable energy increase for the PJM portfolio. We have estimated the system-wide incremental changes in air emission for the following six conventional plant generation types:

- Sub-Critical Coal (35-900 MW)
- Large Supercritical Coal (500-1300 MW)
- Combined Cycle Units based on LF CT Cost
- Small Gas CT (=50 MW)
- Large Gas CT (50-200 MW)
- Gas Fired Steam Plants (50 MW-700 MW)

The first step of this analysis is to calculate coefficients of emissions per cycle based on actual historical operation of the units. Following this step, we use the emissions per load follow (ramp) and start/stop cycle to determine the emissions of each of the unit types for the following scenarios:

- 2% BAU: Business As Usual [all other scenarios are compared to this baseline]
- 14% RPS: Renewable Portfolio Standard Reference Scenario
- 20% HOBO: High Offshore Best Sites Onshore

- 20% HSBO: High Solar Best Sites Onshore
- 20% LOBO: Low Offshore Best Sites Onshore
- 20% LODO: Low Offshore Dispersed Sites Onshore
- 30% HOBO: High Offshore Best Sites Onshore
- 30% HSBO: High Solar Best Sites Onshore
- 30% LOBO: Low Offshore Best Sites Onshore
- 30% LODO: Low Offshore Dispersed Sites Onshore

The percentages above reflect the amount of renewable wind and solar energy in the PJM portfolio, with 2% representing the current state of affairs.

2.1.1 Purpose and Objectives

The annual emissions of NOx and SOx for gas and coal-fired steam, simple cycle gas turbine and gas turbine combined cycle plants are affected by unit cycling. Power plant cycling influences the emissions output of power plants because of potential changes in the unit's heat rate, reliability, effectiveness of emissions control equipment as well as emission rates (lbs/MMBtu) during startup, shutdown, and load cycling. The power plant emissions for each of the six groups of plant types were analyzed to derive the incremental change in emissions based on the MW dispatch and other inputs provided by the GE-MAPS. Power plant cycling refers to both on-off transients (starts-shutdowns) and load following (ramps).

- Start and shutdown cycles were counted on a per day basis. A unit that only has a startup on a given day would have a half start/stop cycle. This ensured that we accounted for the entire start-shutdown cycle of the unit for the emissions analysis.
- Load Following is the process of adjusting unit electrical output with demand. For this analysis, we assumed a MW load change of magnitude greater than 20% and less than 70% of the unit's maximum rating.
- Preliminary analysis yielded insignificant impact from the rate of change of unit MW output during a load-following event. Since the ramp rate during a load follow event did not matter, it was not examined. But the investigation tracked whether or not the unit was ramping, and correlate that with the emissions output.
- Traditional production-cost models estimate emissions using emission factors (lbs/MMBtu) based on steady-state operation of the plant and do not take into

account on-off cycling[12] or load cycling. The analysis described in this section provides PJM greater insights into the total expected changes in power plant emissions for the study scenarios, including cycling and ramping effects. This study does not examine the legal compliance of any of these units to applicable emission regulations.

2.1.2 Methodology and Scope

In this investigation we have estimated the system-wide incremental changes in air emission for six conventional plant generation types. Actual historical power plant emissions were analyzed to derive the impact of plant cycling on each type of power plant. Results are presented, with and without cycling impact on emissions of the fossil units, for the ten scenarios described above. GE MAPS production cost simulations were used to calculate the steady state "without cycling" emission amounts, which were then updated using Intertek's regression results to generate the total "with cycling" emissions estimates. The results for each of the incremental renewable energy scenarios were then compared to the 2% BAU scenario, where

Total Emissions = Steady State Emissions (from GE MAPS)
+ Extra Cycling-Related Emissions (from Intertek AIM Regression Model)

There are two major databases that were utilized in this study:

1. U. S. Environmental Protection Agency (EPA) Continuous Monitoring (CEM) data that is comprised of: hourly measured emissions, MW, and heat input data for the same units analyzed back to 2001 for regression. We found that data since 2009 was the best quality. Before that, we found that many of the current plant emissions control equipment were not yet installed. This caused issues when looking at a unit that had equipment that was not constant and was changing during the year. The historical analysis yielded the coefficients of emissions per cycle for each unit type based on actual operation.
2. GE provided hourly output profile data from MAPS for the 180-unit sample of units: MW; heat input (MMBtu); Steady State NOx and SOx (by mass) for each of the future scenarios. We applied our regression results to each of these scenarios to calculate the total emissions with the effects of cycling. Additionally, GE provided total annual

[12] When units are offline, there is no heat input or emissions. This is true when GE MAPS models emissions. However, there are inefficiencies involved with unit startups that are not accounted for with steady state emissions estimates.

energy, heat input, and steady state emissions amounts for all PJM units in the scenarios, which were extrapolated to estimate the total emissions per scenario.

In order to determine the changes in emissions from cycling for each unit type, we modeled the historical emissions measurements for 180 units of the PJM portfolio for a 12 year time horizon (2001-11) using the CEMS data set. The EPA reports MW generation, heat input (fuel flow in MMBtu), SO2, and NOx emissions every hour the unit operates. The study uses statistical regression methods to determine the cycling impacts on emissions of fossil fired power plants for a sample of units that represents the PJM portfolio. The multivariate regression analysis was performed for each emission type – SOx and NOx, for each unit of the six categories of unit types. The regression analysis uses a multivariate linear regression. Nonlinear approaches were also examined[13] for the most critical unit types (coal sub- and super-critical) but these offered insignificant improvements for goodness-of-fit. Intertek AIM used the same approach for these analyses that it has used for many years to estimate the effects of cycling on unit heat rates based on the EPA generation and heat input data from the installed CEMs at the plants. Using judicious regression and outlier removal techniques, the "signal" was separated from the "noise" in heat rate data, and a successful regression model was achieved.

From the exploratory analysis of the EPA data we found that the hourly emissions data are even nosier than hourly heat input data. NOx emissions data analyses using hourly data are often plagued by poor fits, unexplained residuals, and possible time lags in the system between hourly heat input and subsequent emissions which might not occur within the same hour. After considerable study, the unit of "days" was chosen for calculating emission rates. That is, we summed the total emissions for the day and divided it by the total heat input for that day to get a daily emission rate. We looked carefully at other time units – notably hours, 8-hour shifts, weeks, and months. The number of outliers was much higher for hourly data and it was difficult to characterize starts and shutdowns based on single hours.

The emissions rates are applied to each future operating scenario to calculate the total emissions which include the full impacts of cycling. These emission levels (total emissions) are then compared to the Steady State emissions (output by MAPS) for the same future scenario that does not consider all of the cycling and ramping effects that were calculated by the regression model.

The regression of the historical measured emissions data for each of the six unit types uses several independent variables:

- load,

[13] We used Stata's "mfp" command—please see http://www.stata.com/help.cgi?mfp.

- time period,
- months of year,
- individual unit,
- start/shutdown cycles,
- weekend-holiday vs. work day,
- emission control, and
- load follows greater than 20% of the unit's full capacity.

In the regression analysis, about 2% of the total data was eliminated as outliers. Only 1% of the coal unit data were included in the outliers, which is comforting given that coal plants tend to dominate emissions impacts during grid operations.

The coefficients derived from the regression models are used to estimate the future emissions for each of the units for different load profiles as defined in the scenario database. The regression coefficients for start-stop cycles are in units of daily extra emission rate per cycle (for days containing at least one start or shutdown). A day with only a start or shutdown was modeled as "half a cycle". The regression coefficients for load following transients are in units of: daily extra emission rate for the largest daily load follow range (as a percent of its capacity). The coefficients from the analyses (for startup-shutdown cycles and load follow magnitude) are used for the scenario calculations to determine the extra emissions. Daily extra emissions are the amount of additional (extra) emissions generated for the day compared to those steady state emissions estimated from the MAPS model. Note that the daily "extra" emissions can positive or negative, i.e., the emissions due to cycling impacts can either increase or decrease compared to the estimates from MAPS for a particular unit type.

Finally, we extrapolate the emissions analysis on the 180 unit sample for the entire PJM portfolio. For each of the scenarios, over 50% of the total MWh and heat input was analyzed. Moreover, majority of the coal fired subcritical and supercritical units along with almost 70% of the energy from combined cycle units was considered in our sample estimates. This gives us confidence that the emissions estimates represent the PJM portfolio adequately.

2.1.3 Results

The total emissions with cycling impacts for the PJM portfolio are dominated by the coal generation. Coal plants (subcritical and supercritical) comprise 97% of the NOx and 99% of the total annual SOx emissions (lbs/yr) for almost all scenarios. The contribution from gas-fired steam plants, combined cycle and simple cycle gas turbine plants is small (See Figure

2-1). We also found that NOx and SOx rates (lbs/MMBtu) increase at low loads for coal plants and decrease for the gas turbine and combined cycle plants. This may be caused by the lower efficiency for the emissions controls at low loads for coal plants. For gas turbines low loads often have lower average flame temperatures leading to lower NOx. Also for all gas burning plants, the SOx emissions are directly correlated to the fuel burned and all sulfur in fuel is converted to SOx.

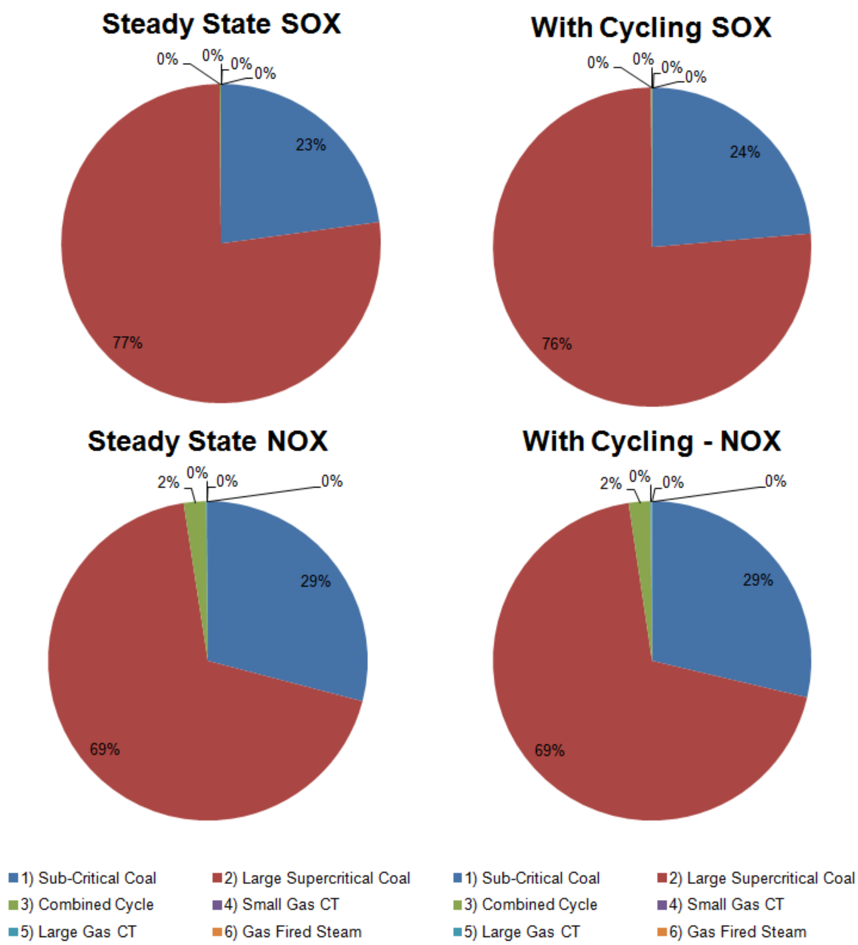

Figure 2-1: Emissions by Unit Type for 14% RPS Scenario, With and Without Cycling Effects

All scenarios are compared to the 2% BAU scenario, which represents the current penetration of renewable energy in the PJM portfolio as shown in Table 2-1 and Table 2-2. The steady state emissions reduction ranged from 5 to 39%, while the, "with cycling" impact emissions for SOx reduction was reduced to 4 to 35%.

Table 2-1: Cycling Impacts for NOx and SOx Emissions

Compared to 2% BAU Scenario	SOx Steady State Reduction in Emissions	SOx Emissions Reduction with Cycling Impacts	SOx Emissions Change Relative to Steady State
14% RPS	5%	4%	-1%
20% HOBO	8%	4%	-4%
20% HSBO	9%	7%	-2%
20% LOBO	10%	7%	-3%
20% LODO	9%	7%	-2%
30% HOBO	14%	9%	-5%
30% HSBO	21%	18%	-3%
30% LOBO	39%	35%	-4%
30% LODO	25%	23%	-2%
Compared to 2% BAU Scenario	**NOx Steady State Reduction in Emissions**	**NOx Emissions Reduction with Cycling Impacts**	**NOx Emissions Change Relative to Steady State**
14% RPS	6%	6%	0%
20% HOBO	10%	8%	-2%
20% HSBO	9%	9%	0%
20% LOBO	14%	13%	-1%
20% LODO	12%	12%	0%
30% HOBO	16%	14%	-2%
30% HSBO	19%	18%	-1%
30% LOBO	36%	36%	0%
30% LODO	23%	22%	-1%

Table 2-2: Comparing Total MWh, Heat Input and CO2 to the 2% BAU Scenario

Compared to 2% BAU Scenario	Reduction in MWh Energy Output from Coal and Gas plants	Reduction in Heat Input (Fuel)	Reduction in CO2 Emissions
14% RPS	15%	14%	12%
20% HOBO	20%	18%	14%
20% HSBO	18%	16%	15%
20% LOBO	19%	19%	18%
20% LODO	18%	18%	17%
30% HOBO	35%	32%	27%
30% HSBO	31%	29%	28%
30% LOBO	40%	40%	41%
30% LODO	30%	29%	29%

Table 2-3, shows the relative contributions of cycling-related emissions impacts on total SOx and NOx emissions. In other words this is the contribution of cycling events to the total emissions (including cyclic impacts). Note, that load follow results are dominated by Supercritical Coal.

Table 2-3: Relative Contribution of On/Off Cycling and Load-Follow Cycling to Emissions

	SOX Impact From		NOX Impact From	
	On/Off	Load Follow	On/Off	Load Follow
2% BAU	0%	2%	0%	1%
14% RPS	0%	3%	1%	2%
20% HOBO	0%	6%	0%	3%
20% HSBO	0%	4%	0%	2%
20% LOBO	1%	4%	1%	2%
20% LODO	1%	4%	1%	2%
30% HOBO	1%	7%	1%	4%
30% HSBO	1%	5%	1%	2%
30% LOBO	1%	6%	1%	2%
30% LODO	1%	5%	1%	2%

Figure 2-2 and Figure 2-3 show the overall results of the emissions analysis. In Figure 2-2, the dark blue bars show steady-state SOx emissions as calculated by the production cost simulations. The dark red bars stacked over the dark blue bars show incremental SOx emissions due to unit cycling. In Figure 2-3, the green and orange bars show similar results for NOx emissions. The black lines show total generation energy from the thermal power plants. The results indicate that SOx and NOx emissions decline as renewable penetration increases, but increased cycling causes the reduction to be somewhat smaller than would be calculated by simply considering a constant emission rate per MMBtu of energy consumed at gas and coal generation facilities.

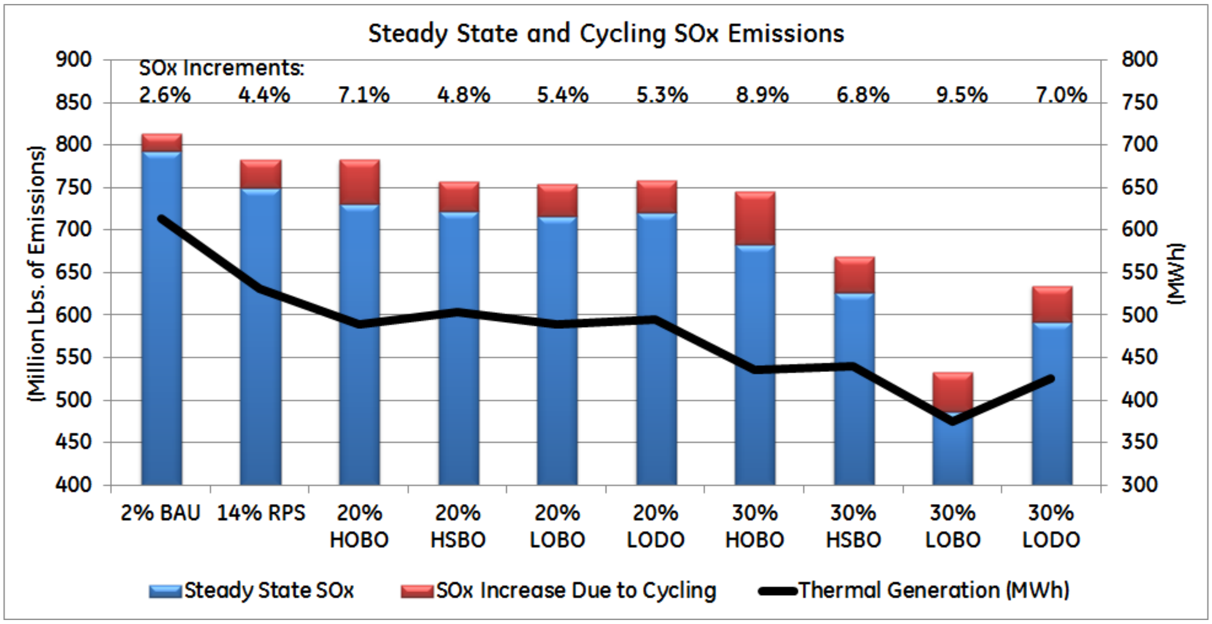

Figure 2-2: SOx Emissions for Study Scenarios, With and Without Cycling Effects Included

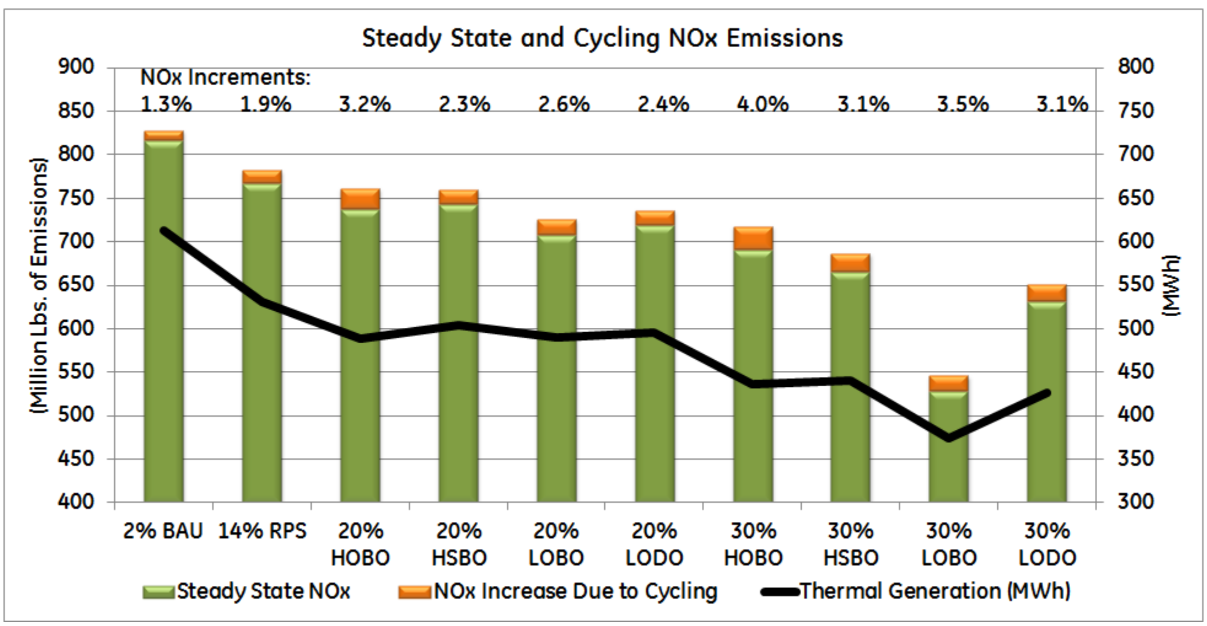

Figure 2-3: NOx Emissions for Study Scenarios, With and Without Cycling Effects Included

As shown in Table 2-1 the NOx emissions reduction from the 2% scenario for both the steady state estimates and the "with cycling" estimates ranged from 6% in the 14% RPS scenario to 36% in the 30% LOBO scenario. The emission reductions for the scenarios with increased renewable energy are still significant when cycling impacts are included, although they the reductions in emissions are somewhat smaller when compared to the steady state emissions calculations.

Table 2-4 displays the cycling impacts on reduction of coal and gas plant energy outputs, fuel usage, and CO2 emissions, for each scenario compared to the 2% BAU scenario.

Table 2-4: Impact of Cycling on Coal and Gas Plant Energy Outputs, Fuel Usage, and CO2 Emissions

Scenario	Reduction in MWh Energy Output from Coal and Gas Plants Relative to 2% BAU Scenario	Reduction in Heat Input (Fuel) Relative to 2% BAU Scenario	Reduction in CO2 Emissions Relative to 2% BAU Scenario
14% RPS	15%	14%	12%
20% HOBO	20%	18%	14%
20% HSBO	18%	16%	15%
20% LOBO	19%	19%	18%
20% LODO	18%	18%	17%
30% HOBO	35%	32%	27%
30% HSBO	31%	29%	28%
30% LOBO	40%	40%	41%
30% LODO	30%	29%	29%

2.1.4 Tables of Results

A summary of the extrapolated annual emission results for the 2% BAU and the 14% RPS scenarios is presented in Table 2-5 and Table 2-6 respectively. In these tables the annual SOx and NOx emissions (in lbs.) for each of the six unit types (sub-critical coal, supercritical coal, combined cycle, small gas CT, Large gas CT, and Gas-fired steam units) are tabulated. In the first column of the tables, the steady-state emissions from the GE MAPS model are given. These emissions do not include the full impacts of cycling. The second column gives the change in annual emissions (positive or negative) due to on/off cycling. The next column shows the change in annual emissions due to load following. The last column is the total emissions including both steady-state, on/off cycling, and load follow cycling. Note that these results take into account the number of cycles that each unit type experiences in the scenario as well as the impact of those cycling operations on the production of emissions. For example, CT units do not experience much load following in these two scenarios, thus the impact of load following emissions is nil for CT units.

By comparing the emission rates (lbs/MMBtu) and steady state vs. total cycling for the different unit types, it is evident that the NOx and SOx rates (lbs/MMBtu) increase at low loads for coal plants and decrease for the combustion turbines. On/off cycling in the small and large CTs reduces the amount of NOx emissions generation rate (lbs/Btu) thus the NOx emissions from the CTs are reduced due to on/off cycling. On the other hand the NOx emissions from the coal-fired plants increase during cycling most likely because the NOx reduction technologies for coal plants are less effective during startups.

Table 2-5: Annual Extrapolated Emissions for the 2% BAU Scenario

2% Scenario	Steady State SOX (lbs)	SOX Emissions from Start/Stop Cycle (lbs)	SOX Emissions from Load Follow Cycle (lbs)	Total SOX Emissions with Cycling Impact (lbs)
1) Sub-Critical Coal	262,134,574	2,068,690	6,425,543	270,628,807
2) Large Supercritical Coal	529,314,252	828,701	11,252,763	541,395,716
3) Combined Cycle	715,769	1,285	3,392	720,446
4) Small Gas CT	524,909	0	0	524,909
5) Large Gas CT	438,230	91,831	0	530,062
6) Gas Fired Steam	57	0	0	57
Total	793,127,791	2,990,508	17,681,698	813,799,997

2% Scenario	Steady State NOX (lbs)	NOX Emissions from Start/Stop Cycle (lbs)	NOX Emissions from Load Follow Cycle (lbs)	Total NOX Emissions with Cycling Impact (lbs)
1) Sub-Critical Coal	311,227,505	794,202	645,642	312,667,349
2) Large Supercritical Coal	471,815,029	1,930,237	8,850,736	482,596,002
3) Combined Cycle	23,127,472	234,357	-413,119	22,948,710
4) Small Gas CT	7,536,191	-1,019,167	0	6,517,024
5) Large Gas CT	3,511,765	-243,130	0	3,268,635
6) Gas Fired Steam	72,330	-693	0	71,637
Total	817,290,293	1,695,805	9,083,260	828,069,358

Table 2-6: Annual Extrapolated Emissions for the 14% RPS Scenario

14% Scenario	Steady State SOX (lbs)	SOX Emissions from Start/Stop Cycle (lbs)	SOX Emissions from Load Follow Cycle (lbs)	Total SOX Emissions with Cycling Impact (lbs)
1) Sub-Critical Coal	248,235,680	2,509,008	16,116,780	266,861,468
2) Large Supercritical Coal	500,894,240	1,207,057	12,827,291	514,928,588
3) Combined Cycle	541,324	1,421	2,311	545,056
4) Small Gas CT	487,575	0	0	487,575
5) Large Gas CT	173,350	39,656	0	213,006
6) Gas Fired Steam	36	0	0	36
Total	750,332,206	3,757,142	28,946,382	783,035,729

14% Scenario	Steady State NOX (lbs)	NOX Emissions from Start/Stop Cycle (lbs)	NOX Emissions from Load Follow Cycle (lbs)	Total NOX Emissions with Cycling Impact (lbs)
1) Sub-Critical Coal	289,110,694	956,243	1,607,648	291,674,585
2) Large Supercritical Coal	453,875,492	2,822,510	10,128,616	466,826,618
3) Combined Cycle	17,200,060	264,782	-287,380	17,177,462
4) Small Gas CT	5,353,215	-758,690	0	4,594,526
5) Large Gas CT	2,175,790	-162,075	0	2,013,715
6) Gas Fired Steam	53,782	-507	0	53,275
Total	767,769,034	3,122,263	11,448,884	782,340,181

Table 2-7 to Table 2-16 in Appendix B present results from the sample of 180 units for each of the renewable scenarios.

2.1.5 Conclusions

This analysis calculated total annual emissions for coal and gas-fired units in PJM for all the study scenarios. The analysis included the effects of on/off cycling and load-following (ramps) in addition to the steady-state emissions that are calculated by the MAPS production simulation program. The analysis illustrated that emissions in the PJM system will be reduced as wind and solar penetration increases. However, the emissions reductions will be somewhat less than that predicted by production cost analysis if cycling effects are taken into account. For example, in the 30% LOBO scenario, the MAPS analysis calculates a 39% reduction in SOx emissions as compared to the 2% BAU scenario. If cycling impacts are taken into account, there is only a 35% reduction in SOx emissions for the 30% LOBO scenario.

The main observations and conclusions from this analysis are:

- Emissions from coal plants comprise 97% of the NOx and 99% of the SOx emissions
- For scenarios that experience increased cycling, the results are dominated by supercritical coal emissions.
- NOx and SOx rates (lbs/MMBtu) increase at low loads for coal plants and decrease for CTs
- Including the effects of cycling in emissions calculations does not dramatically change the level of emissions for scenarios with higher levels of renewable generation. However, on/off cycling and load-following ramps do increase emissions over steady state levels. This analysis has provided quantified data on the magnitudes of those impacts.

2.2 Appendix A: Emissions Analysis Statistical Regression, Inputs and Assumptions

Regression modeling focuses on the relationship between a ***dependent variable*** and several ***independent variables***. More specifically, regression analysis helps one understand how the typical value of the dependent variable changes when any one of the independent variables is varied, while the other independent variables are held fixed.

2.2.1 Independent Variables

The regression analysis modeled the following independent variables:

- MW load level as a fraction of unit capacity,
- Passage of time - using data limited to the latest three years for each unit. Figures 1 and 2 use two types of monthly emission rate averages to show dramatic variations for a representative large coal unit. Most units showed much less variations in the last 3 years than in the full 12-year data period. Also, emission rates tended to be lower more recently, perhaps reflecting more emission controls in some units,
- Month of the year - to pick up seasonal effects which can be quite pronounced for some units, as indicated in Figures 1 and 2,
- Individual unit - unit-to-unit emission rate variation is very large, even within the same unit type.
- The presence or absence of emission controls,
- Working days vs. weekends or holidays,

- The maximum range of daily load follow transients - we ignored all cyclic transients of range less than 20% of the unit's MW capacity. We also ignored load follows during days that experienced at least one start or shutdown, and
- The number of daily start-shutdown cycles, if any.

Efforts were made to verify that there was no auto-correlation among all the variables discussed above.

2.2.2 Regression Coefficients

The coefficients derived from our regression models are used to estimate the future emissions for each of the units for different load profiles as defined in the scenario database. The key regression coefficients used in the cycling emission scenario calculations were for start-shutdown cycles and load follow magnitude. When these coefficients were statistically insignificant[14], they were ignored—that is, set equal to zero in the scenario analysis. That explains the zero entries in tabulation of results presented in Tables 1 through 10 (Appendix 2) for the four 20%, and four 30% renewable scenarios. The dominant coal units had cycling and load follow NOx and SOx regression coefficients that were all positive and statistically significant, indicating that cycling these units increases NOx and SOx emissions.

The regression coefficients for start-stop cycles are expressed in units of *daily extra emission rate* per cycle (for days containing at least one start or shutdown, each modeled as "half a cycle"). Each such day can have different total heat input and different numbers of starts and shutdowns, and therefore, changing the rate will have different effects each day. Figure 2-4 to Figure 2-7 illustrate this considerable variation in daily emissions for such cycles of the coal units.

The regression coefficients for load following transients (of range exceeding 20% MW capacity) are in units of daily extra emission rate per for the largest daily load follow's percent range (for days containing at least one such load follow but no start or shutdowns). Since each such day can have different total heat input, changing the rate will have different

14 Statistical significance is defined in terms of the "p-value" in regression analyses. This p-value probability is used as a criterion to state whether or not the association between an independent variable and emission is statistically significant. Here, a result is considered statistically significant if it is unlikely to have occurred by chance. The amount of evidence required to accept that an event is unlikely to have arisen by chance is known as the significance level or critical p-value conventionally set equal to 0.05 (5%), 1%, or 10%. Here we used a p<1% to defines statistical significance, p>10% to define insignificance and 1% ≤ p ≤ 10% to define marginal significance. This p-value is the probability conditional on the "null hypothesis" of no impact on emissions. If the obtained p-value is smaller than the critical 1%, then it can be said either the null hypothesis is false or an unusual event has occurred.

effects each day. Figure 2-8 to Figure 2-11 also demonstrate this considerable variation in daily emissions for the load cycling of the coal units. They also show that load following produced more NOx emissions in supercritical coal units than in subcritical coal ones.

Figure 2-12 shows the distribution of residuals after outlier removal for subcritical coal units. Figure 2-13 is a sunflower plot[15], comparing fit and actual emission rates. In a perfect fit, all data points would fall on the red line. Clearly, while the great majority of the data are close to the red line, there is plenty of scatter even after the worst outliers were removed.

2.2.3 Handling Outliers

Data outliers are identified and judiciously eliminated. Intertek AIM used the same outlier handling procedure we use in our cycling heat rate analysis. The general procedure:

3. Conduct statistical regression fit of all data.
4. Calculate the residuals and statistically summarize them.
5. Inspect the distribution of residuals manually, using plots as needed.
6. Remove only the worst outliers (highest absolute valued residuals).
7. If the key regression coefficients change significantly, try removing a few more high residuals.
8. Stop when the key regression coefficients stabilize.

A total of 12 regression models were developed, SOx and NOx for all six unit types. In all cases but one, less than 1% of the data were identified as outliers. In the exceptional case (for SOx emissions of Small GTs) about 2% of the data were discarded. For each of the four coal unit regressions, less than ½% of the data were discarded as outliers.

[15] Density-distribution sunflower plots are used to display high-density bivariate data. They are useful for data where a conventional scatterplot is difficult to read due to overstriking of the plot symbol.

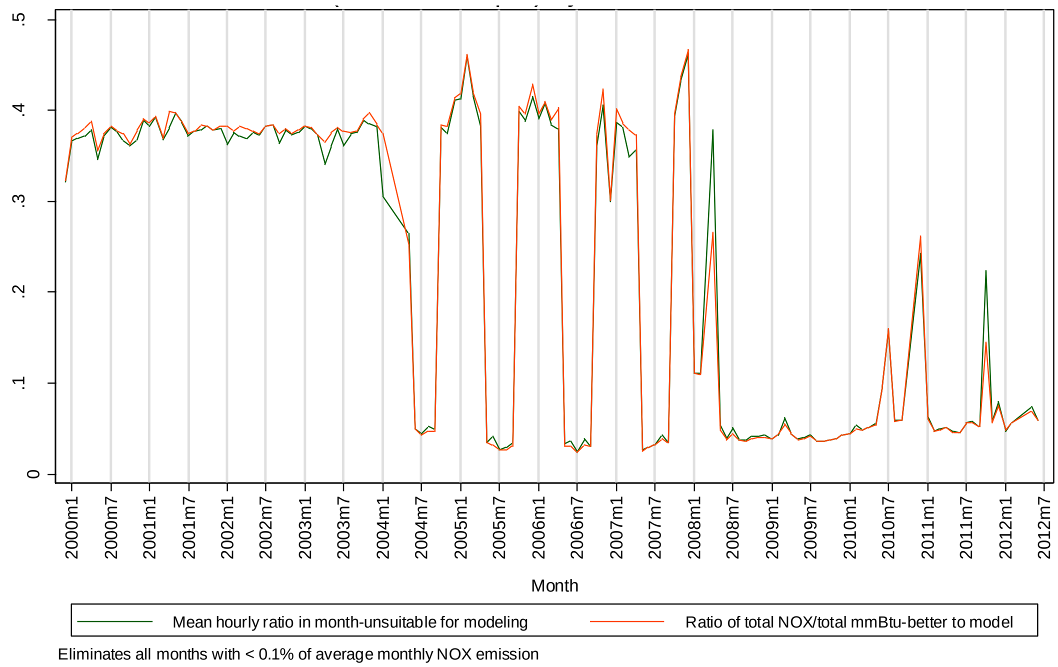

Figure 2-4: Ratio of NOX/Heat Input by Month for a Representative Large Coal Unit

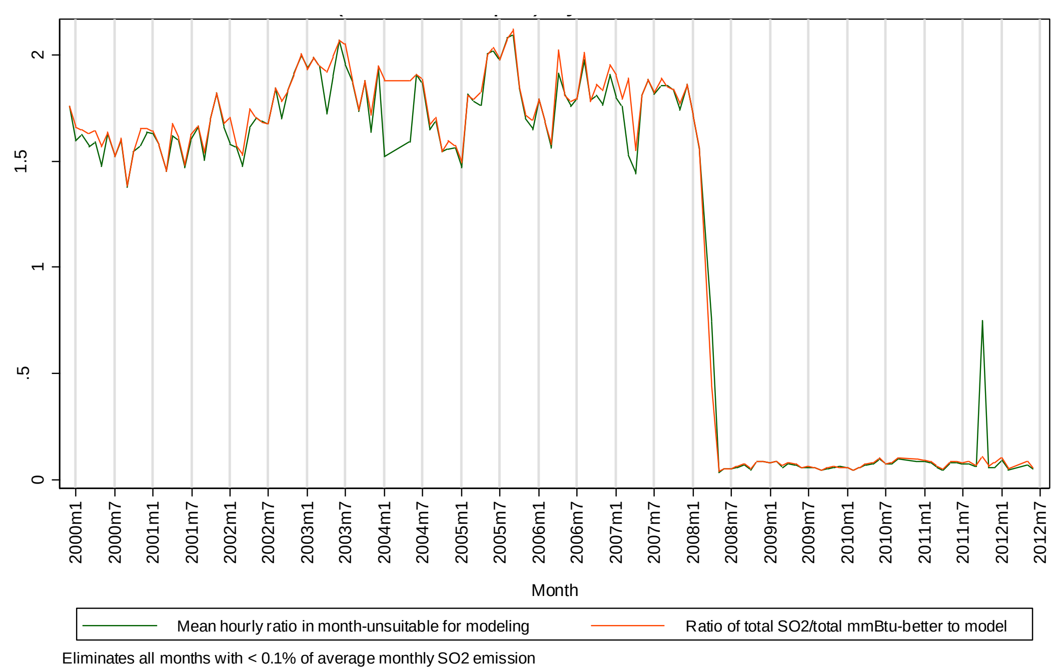

Figure 2-5: Ratio of SO2/Heat Input by Month for a Representative Large Coal Unit

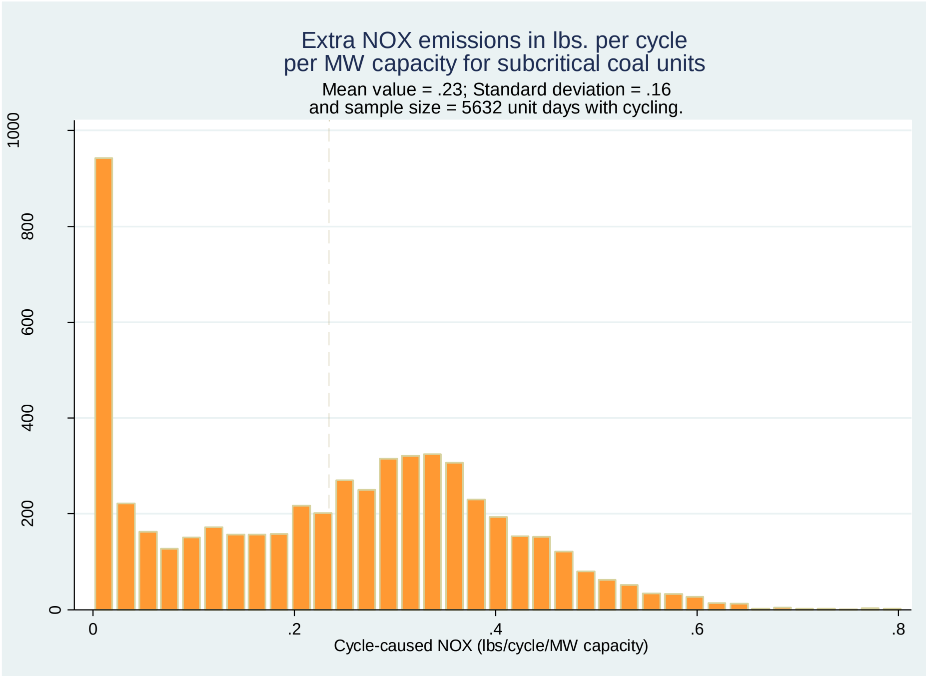

Figure 2-6: Extra NOx Emissions per Cycle per MW Capacity for Subcritical Coal Units

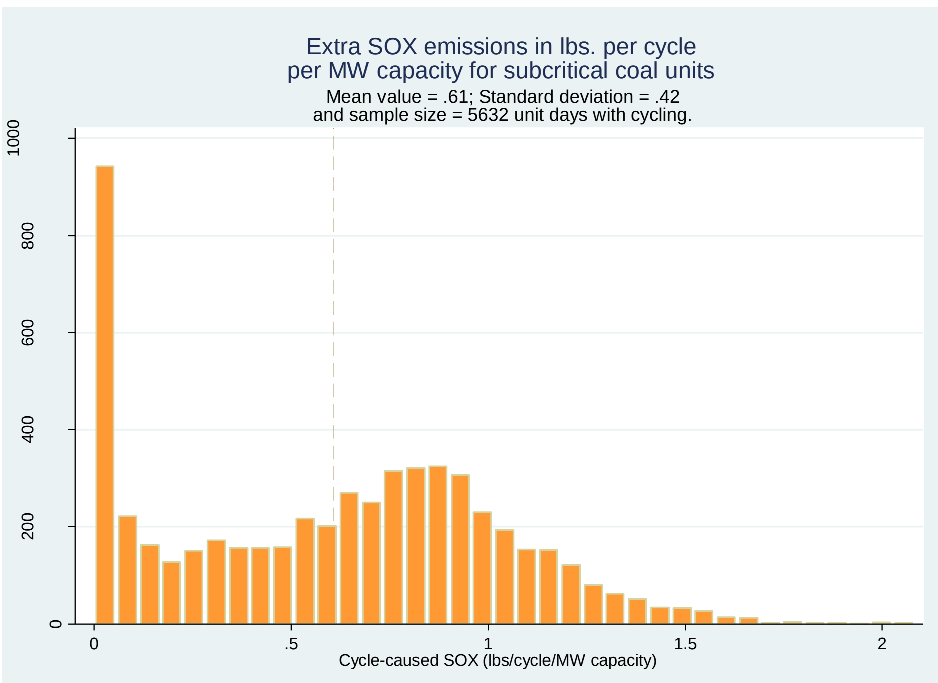

Figure 2-7: Extra SOX Emissions per Cycle per MW Capacity for Subcritical Coal Units

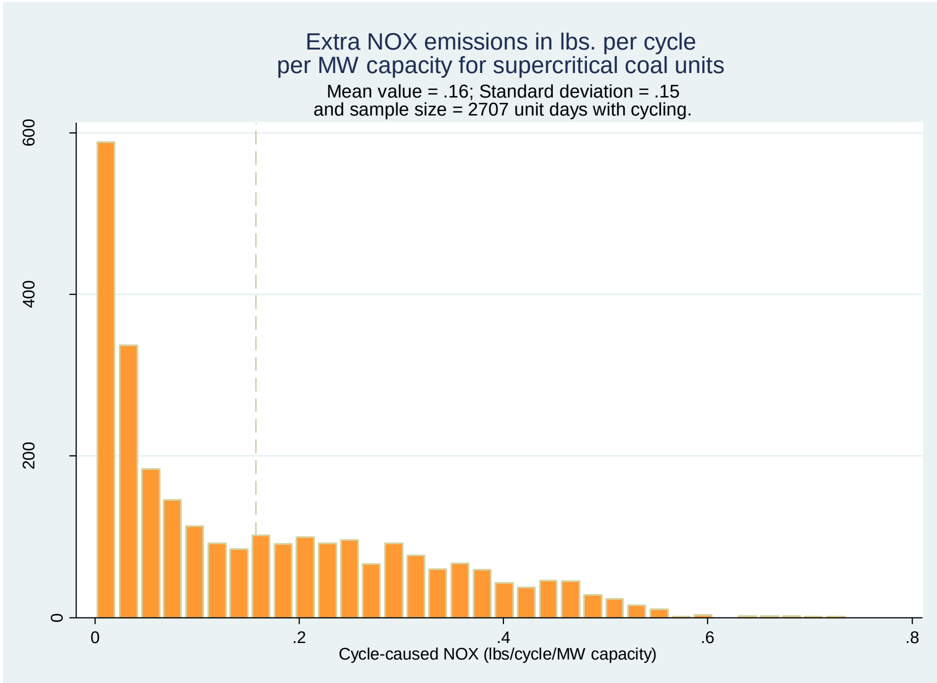

Figure 2-8: Extra NOx Emissions per Cycle per MW Capacity for Supercritical Coal Units

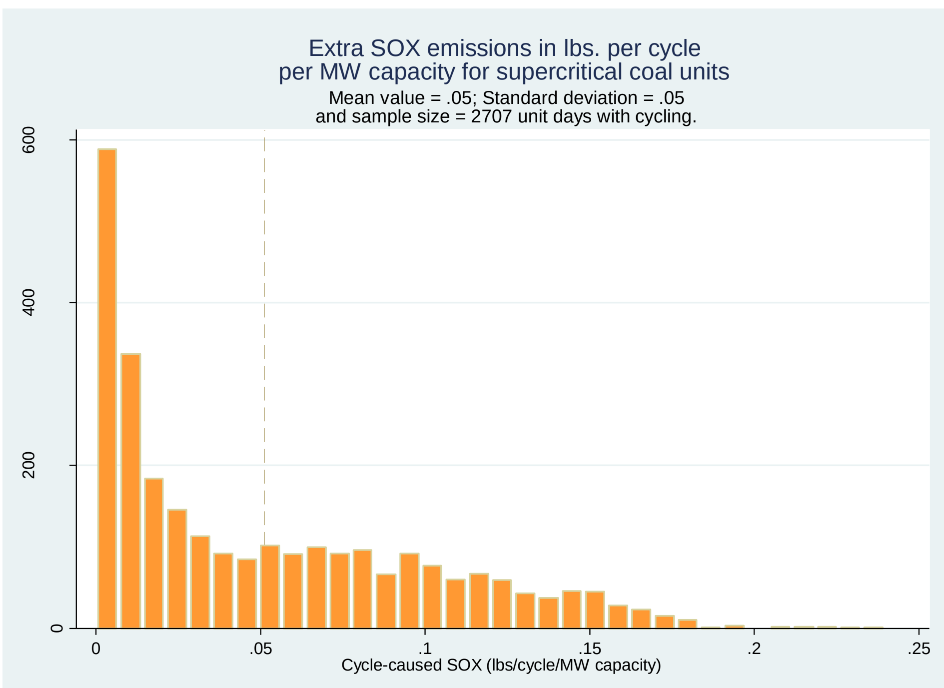

Figure 2-9: Extra SOx Emissions per Cycle per MW Capacity for Supercritical Coal Units

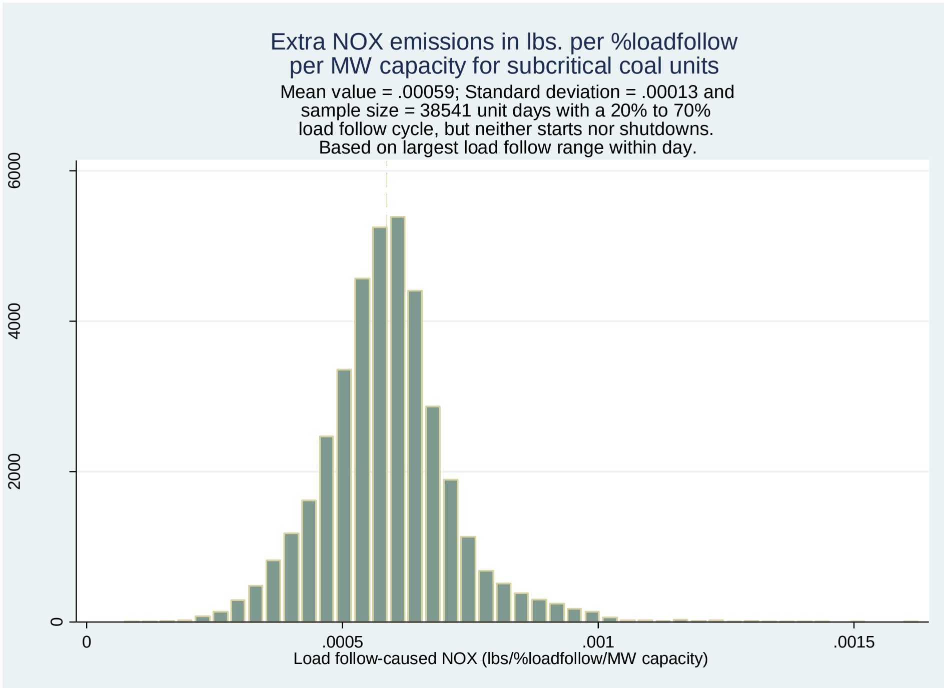

Figure 2-10: Extra NOx Emissions per % Load Flow per MW Capacity for Subcritical Coal Units

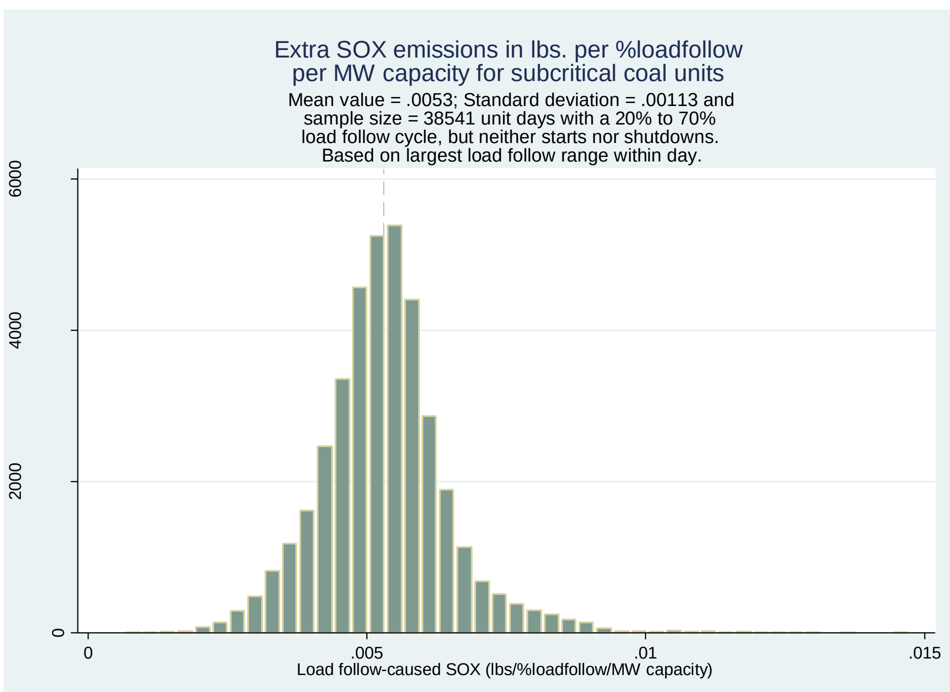

Figure 2-11: Extra SOx Emissions per % Load-Follow per MW Capacity for Subcritical Coal Units

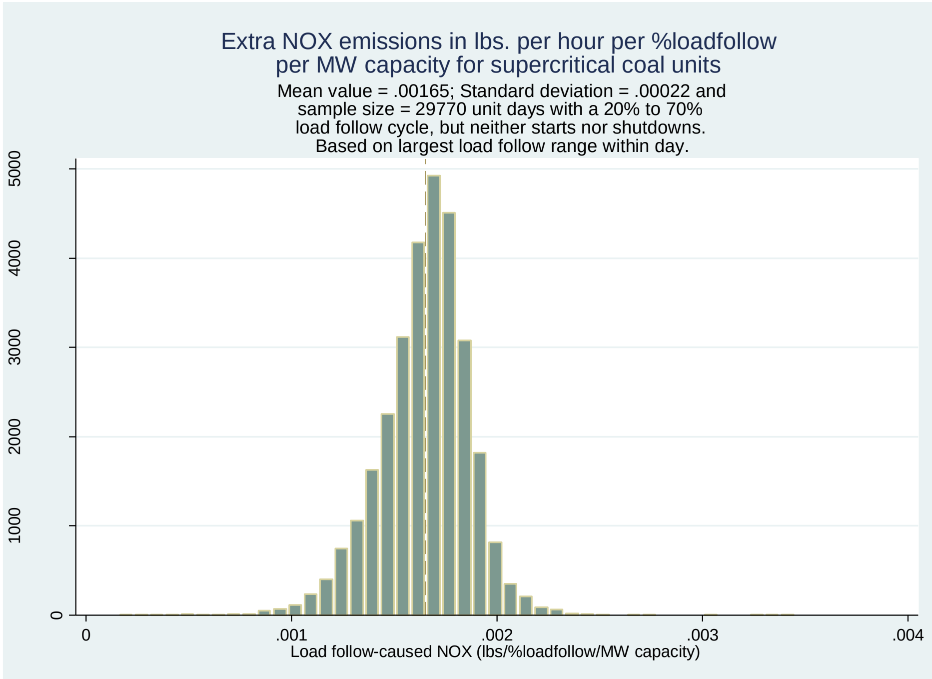

Figure 2-12: Supercritical Coal Units Extra NOx Emissions per Hour per % Load-Follow per MW Capacity

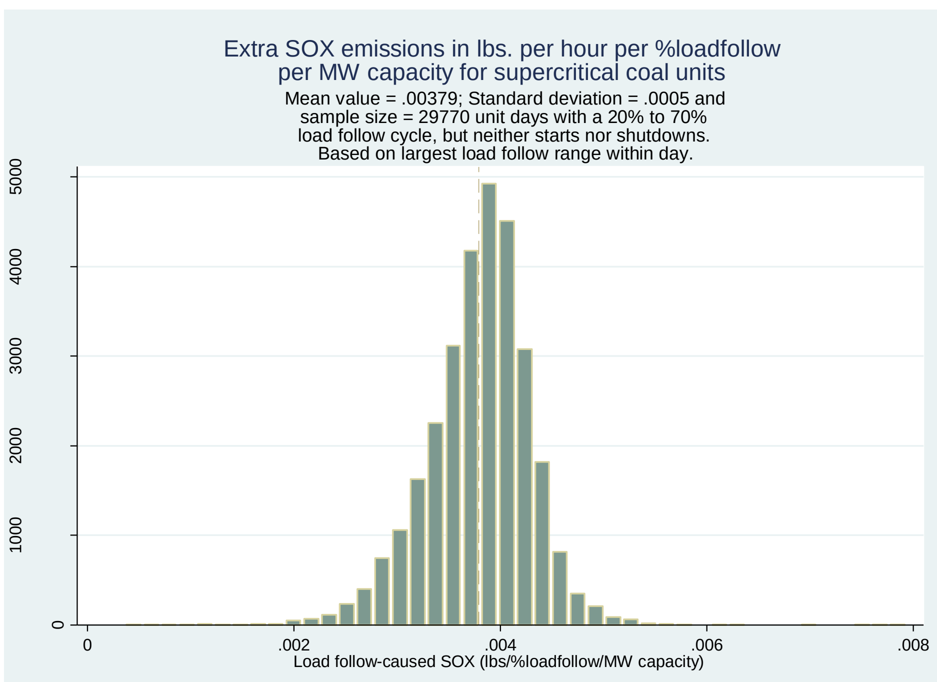

Figure 2-13: Supercritical Coal Units Extra SOx Emissions per Hour per % Load-Follow per MW Capacity

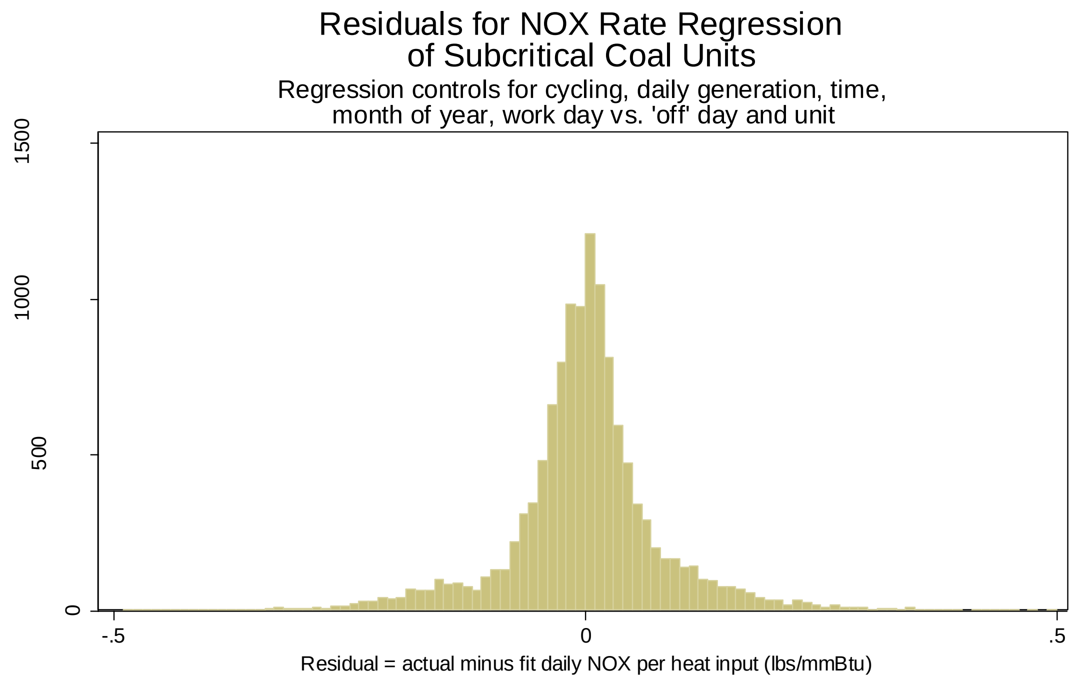

Figure 2-14: Residual for NOx Rate Regression of Subcritical Coal Units

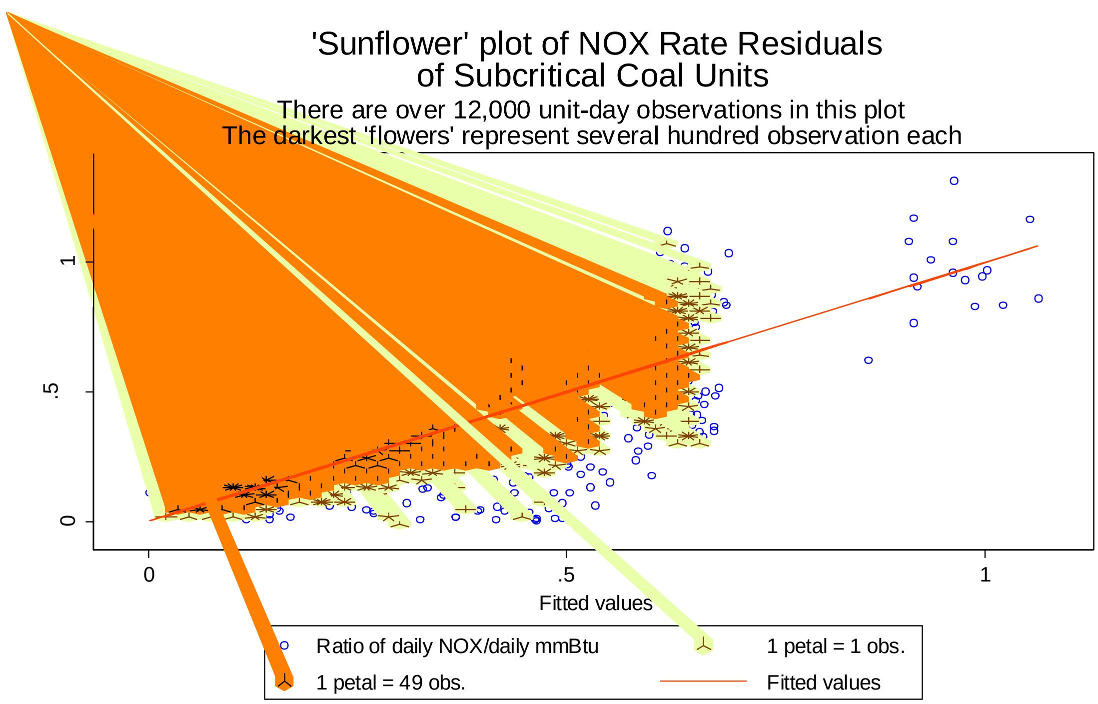

Figure 2-15: "Sunflower" Plot of NOx Rate Residuals of Subcritical Coal Units

2.3 Appendix B: Emissions Analysis Results for the PJM Portfolio (180 Unit Sample)

Table 2-7: Emissions Results - 2% BAU

2% BAU	Steady State SOX (lbs)	SOX Emissions from Start/Stop Cycle (lbs)	SOX Emissions from Load Follow Cycle (lbs)	Total SOX Emissions with Cycling Impact (lbs)
1) Sub-Critical Coal	91,345,464	720,872	2,239,095	94,305,431
2) Large Supercritical Coal	312,460,507	489,192	6,642,640	319,592,340
3) Combined Cycle	611,033	1,097	2,896	615,026
4) Small Gas CT	11,744	0	0	11,744
5) Large Gas CT	66,991	14,038	0	81,029
6) Gas Fired Steam	57	0	0	57
Total	404,495,796	1,225,199	8,884,631	414,605,627

2% BAU	Steady State NOX (lbs)	NOX Emissions from Start/Stop Cycle (lbs)	NOX Emissions from Load Follow Cycle (lbs)	Total NOX Emissions with Cycling Impact (lbs)
1) Sub-Critical Coal	109,091,654	278,384	226,311	109,596,349
2) Large Supercritical Coal	254,477,997	1,041,092	4,773,730	260,292,820
3) Combined Cycle	11,688,048	118,438	-208,780	11,597,706
4) Small Gas CT	130,808	-17,690	0	113,118
5) Large Gas CT	817,905	-56,626	0	761,279
6) Gas Fired Steam	48,981	-469	0	48,513
Total	376,255,393	1,363,129	4,791,261	382,409,785

Table 2-8: Emissions Results - 14% RPS

14% RPS	Steady State SOX (lbs)	SOX Emissions from Start/Stop Cycle (lbs)	SOX Emissions from Load Follow Cycle (lbs)	Total SOX Emissions with Cycling Impact (lbs)
1) Sub-Critical Coal	87,448,046	883,869	5,677,592	94,009,507
2) Large Supercritical Coal	294,871,715	710,583	7,551,305	303,133,603
3) Combined Cycle	432,640	1,136	1,847	435,622
4) Small Gas CT	6,943	0	0	6,943
5) Large Gas CT	43,141	9,869	0	53,009
6) Gas Fired Steam	36	0	0	36
Total	382,802,521	1,605,457	13,230,744	397,638,720

14% RPS	Steady State NOX (lbs)	NOX Emissions from Start/Stop Cycle (lbs)	NOX Emissions from Load Follow Cycle (lbs)	Total NOX Emissions with Cycling Impact (lbs)
1) Sub-Critical Coal	103,197,728	341,330	573,848	104,112,905
2) Large Supercritical Coal	243,178,811	1,512,253	5,426,741	250,117,805
3) Combined Cycle	7,967,529	122,654	-133,122	7,957,062
4) Small Gas CT	99,643	-14,122	0	85,521
5) Large Gas CT	534,393	-39,807	0	494,585
6) Gas Fired Steam	30,961	-292	0	30,669
Total	355,009,065	1,922,016	5,867,467	362,798,547

Table 2-9: Emissions Results – 20% HOBO

20% HOBO	Steady State SOX (lbs)	SOX Emissions from Start/Stop Cycle (lbs)	SOX Emissions from Load Follow Cycle (lbs)	Total SOX Emissions with Cycling Impact (lbs)
1) Sub-Critical Coal	86,799,770	979,461	8,990,327	96,769,558
2) Large Supercritical Coal	289,249,223	349,909	13,969,051	303,568,183
3) Combined Cycle	340,571	1,231	1,437	343,239
4) Small Gas CT	1,122	0	0	1,122
5) Large Gas CT	3,591	1,882	0	5,473
6) Gas Fired Steam	30	0	0	30
Total	376,394,307	1,332,483	22,960,815	400,687,605

20% HOBO	Steady State NOX (lbs)	NOX Emissions from Start/Stop Cycle (lbs)	NOX Emissions from Load Follow Cycle (lbs)	Total NOX Emissions with Cycling Impact (lbs)
1) Sub-Critical Coal	101,731,267	378,245	908,674	103,018,186
2) Large Supercritical Coal	236,048,443	744,672	10,038,851	246,831,966
3) Combined Cycle	6,295,035	132,939	-103,610	6,324,365
4) Small Gas CT	13,649	-2,127	0	11,522
5) Large Gas CT	89,369	-7,592	0	81,777
6) Gas Fired Steam	26,118	-246	0	25,872
Total	344,203,881	1,245,891	10,843,915	356,293,688

Table 2-10: Emissions Results - 20% HSBO

20% HSBO	Steady State SOX (lbs)	SOX Emissions from Start/Stop Cycle (lbs)	SOX Emissions from Load Follow Cycle (lbs)	Total SOX Emissions with Cycling Impact (lbs)
1) Sub-Critical Coal	83,411,298	786,401	5,758,394	89,956,092
2) Large Supercritical Coal	288,182,640	584,757	9,263,840	298,031,236
3) Combined Cycle	429,447	1,415	1,783	432,645
4) Small Gas CT	2,129	0	0	2,129
5) Large Gas CT	10,714	5,718	0	16,432
6) Gas Fired Steam	22	0	0	22
Total	**372,036,250**	**1,378,291**	**15,024,017**	**388,438,556**

20% HSBO	Steady State NOX (lbs)	NOX Emissions from Start/Stop Cycle (lbs)	NOX Emissions from Load Follow Cycle (lbs)	Total NOX Emissions with Cycling Impact (lbs)
1) Sub-Critical Coal	99,543,597	303,690	582,015	100,429,301
2) Large Supercritical Coal	237,526,003	1,244,472	6,657,454	245,427,929
3) Combined Cycle	8,033,186	152,846	-128,489	8,057,544
4) Small Gas CT	30,448	-4,341	0	26,107
5) Large Gas CT	287,437	-23,064	0	264,374
6) Gas Fired Steam	19,219	-181	0	19,038
Total	**345,439,890**	**1,673,422**	**7,110,980**	**354,224,293**

Table 2-11: Emissions Results - 20% LOBO

20% LOBO	Steady State SOX (lbs)	SOX Emissions from Start/Stop Cycle (lbs)	SOX Emissions from Load Follow Cycle (lbs)	Total SOX Emissions with Cycling Impact (lbs)
1) Sub-Critical Coal	82,350,687	1,697,137	6,152,266	90,200,091
2) Large Supercritical Coal	285,094,741	702,399	9,031,675	294,828,815
3) Combined Cycle	454,784	1,476	1,682	457,941
4) Small Gas CT	4,307	0	0	4,307
5) Large Gas CT	15,703	5,872	0	21,575
6) Gas Fired Steam	32	0	0	32
Total	367,920,254	2,406,884	15,185,623	385,512,761

20% LOBO	Steady State NOX (lbs)	NOX Emissions from Start/Stop Cycle (lbs)	NOX Emissions from Load Follow Cycle (lbs)	Total NOX Emissions with Cycling Impact (lbs)
1) Sub-Critical Coal	91,250,855	655,395	621,825	92,528,075
2) Large Supercritical Coal	234,271,262	1,494,836	6,490,609	242,256,707
3) Combined Cycle	8,636,986	159,387	-121,206	8,675,167
4) Small Gas CT	46,067	-6,193	0	39,873
5) Large Gas CT	291,893	-23,686	0	268,208
6) Gas Fired Steam	27,108	-256	0	26,853
Total	334,524,171	2,279,483	6,991,228	343,794,883

Table 2-12: Emissions Results - 20% LODO

20% LODO	Steady State SOX (lbs)	SOX Emissions from Start/Stop Cycle (lbs)	SOX Emissions from Load Follow Cycle (lbs)	Total SOX Emissions with Cycling Impact (lbs)
1) Sub-Critical Coal	82,569,406	1,455,658	6,542,089	90,567,152
2) Large Supercritical Coal	287,239,232	680,701	8,590,178	296,510,111
3) Combined Cycle	442,001	1,455	1,617	445,072
4) Small Gas CT	4,678	0	0	4,678
5) Large Gas CT	21,785	6,437	0	28,222
6) Gas Fired Steam	24	0	0	24
Total	370,277,126	2,144,251	15,133,884	387,555,259
20% LODO	**Steady State NOX (lbs)**	**NOX Emissions from Start/Stop Cycle (lbs)**	**NOX Emissions from Load Follow Cycle (lbs)**	**Total NOX Emissions with Cycling Impact (lbs)**
1) Sub-Critical Coal	94,674,117	562,141	661,225	95,897,483
2) Large Supercritical Coal	236,387,262	1,448,658	6,173,327	244,009,247
3) Combined Cycle	8,547,109	157,150	-116,531	8,587,728
4) Small Gas CT	45,419	-6,170	0	39,248
5) Large Gas CT	343,967	-25,964	0	318,003
6) Gas Fired Steam	20,978	-198	0	20,780
Total	340,018,852	2,135,617	6,718,021	348,872,489

Table 2-13: Emissions Results - 30% HOBO

30% HOBO	Steady State SOX (lbs)	SOX Emissions from Start/Stop Cycle (lbs)	SOX Emissions from Load Follow Cycle (lbs)	Total SOX Emissions with Cycling Impact (lbs)
1) Sub-Critical Coal	222,194,654	3,573,344	30,108,112	255,876,109
2) Large Supercritical Coal	461,631,055	966,841	26,420,150	489,018,046
3) Combined Cycle	277,769	1,475	755	279,999
4) Small Gas CT	46,125	0	0	46,125
5) Large Gas CT	7,259	8,174	0	15,432
6) Gas Fired Steam	3,217	0	0	3,217
Total	684,160,078	4,549,834	56,529,017	745,238,929

30% HOBO	Steady State NOX (lbs)	NOX Emissions from Start/Stop Cycle (lbs)	NOX Emissions from Load Follow Cycle (lbs)	Total NOX Emissions with Cycling Impact (lbs)
1) Sub-Critical Coal	90,696,007	463,735	1,022,646	92,182,387
2) Large Supercritical Coal	213,660,567	1,156,048	10,667,521	225,484,136
3) Combined Cycle	3,905,926	110,871	-37,883	3,978,913
4) Small Gas CT	7,212	-1,711	0	5,501
5) Large Gas CT	37,311	-3,711	0	33,600
6) Gas Fired Steam	16,318	-154	0	16,164
Total	308,323,341	1,725,078	11,652,284	321,700,701

Table 2-14: Emissions Results - 30% HSBO

30% HSBO	Steady State SOX (lbs)	SOX Emissions from Start/Stop Cycle (lbs)	SOX Emissions from Load Follow Cycle (lbs)	Total SOX Emissions with Cycling Impact (lbs)
1) Sub-Critical Coal	72,012,729	1,494,164	7,492,451	80,999,345
2) Large Supercritical Coal	252,716,979	935,616	9,733,531	263,386,126
3) Combined Cycle	413,857	1,579	1,243	416,679
4) Small Gas CT	924	0	0	924
5) Large Gas CT	8,274	3,888	0	12,162
6) Gas Fired Steam	38	0	0	38
Total	**325,152,801**	**2,435,247**	**17,227,225**	**344,815,274**
30% HSBO	**Steady State NOX (lbs)**	**NOX Emissions from Start/Stop Cycle (lbs)**	**NOX Emissions from Load Follow Cycle (lbs)**	**Total NOX Emissions with Cycling Impact (lbs)**
1) Sub-Critical Coal	88,811,259	577,012	757,280	90,145,550
2) Large Supercritical Coal	210,310,508	1,991,165	6,994,997	219,296,670
3) Combined Cycle	6,706,800	170,550	-89,566	6,787,785
4) Small Gas CT	24,010	-2,977	0	21,033
5) Large Gas CT	184,757	-15,683	0	169,073
6) Gas Fired Steam	32,641	-308	0	32,333
Total	**306,069,975**	**2,719,759**	**7,662,711**	**316,452,444**

Table 2-15: Emissions Results - 30% LOBO

30% LOBO	Steady State SOX (lbs)	SOX Emissions from Start/Stop Cycle (lbs)	SOX Emissions from Load Follow Cycle (lbs)	Total SOX Emissions with Cycling Impact (lbs)
1) Sub-Critical Coal	46,833,599	1,846,625	7,124,190	55,804,414
2) Large Supercritical Coal	193,267,115	1,221,803	7,520,253	202,009,171
3) Combined Cycle	456,785	1,479	1,482	459,747
4) Small Gas CT	4,399	0	0	4,399
5) Large Gas CT	6,979	5,272	0	12,251
6) Gas Fired Steam	40	0	0	40
Total	240,568,917	3,075,179	14,645,925	258,290,022

30% LOBO	Steady State NOX (lbs)	NOX Emissions from Start/Stop Cycle (lbs)	NOX Emissions from Load Follow Cycle (lbs)	Total NOX Emissions with Cycling Impact (lbs)
1) Sub-Critical Coal	79,717,141	713,124	720,059	81,150,324
2) Large Supercritical Coal	155,621,466	2,600,226	5,404,426	163,626,117
3) Combined Cycle	8,090,712	159,748	-106,835	8,143,626
4) Small Gas CT	45,909	-5,623	0	40,286
5) Large Gas CT	235,158	-21,265	0	213,893
6) Gas Fired Steam	34,194	-322	0	33,872
Total	243,744,580	3,445,888	6,017,650	253,208,118

Table 2-16: Emissions Results - 30% LODO

30% LODO	Steady State SOX (lbs)	SOX Emissions from Start/Stop Cycle (lbs)	SOX Emissions from Load Follow Cycle (lbs)	Total SOX Emissions with Cycling Impact (lbs)
1) Sub-Critical Coal	65,915,437	2,228,640	7,050,986	75,195,063
2) Large Supercritical Coal	248,953,163	1,085,650	8,328,822	258,367,636
3) Combined Cycle	455,277	1,558	1,393	458,228
4) Small Gas CT	3,803	0	0	3,803
5) Large Gas CT	8,664	5,443	0	14,107
6) Gas Fired Steam	34	0	0	34
Total	315,336,378	3,321,291	15,381,201	334,038,871

30% LODO	Steady State NOX (lbs)	NOX Emissions from Start/Stop Cycle (lbs)	NOX Emissions from Load Follow Cycle (lbs)	Total NOX Emissions with Cycling Impact (lbs)
1) Sub-Critical Coal	84,847,343	860,649	712,660	86,420,652
2) Large Supercritical Coal	204,276,035	2,310,465	5,985,504	212,572,004
3) Combined Cycle	8,293,790	168,297	-100,387	8,361,699
4) Small Gas CT	39,407	-6,114	0	33,292
5) Large Gas CT	240,728	-21,956	0	218,772
6) Gas Fired Steam	29,259	-276	0	28,984
Total	297,726,562	3,311,065	6,597,777	307,635,403