Integrating Wind

Cost of Cycling Analysis
For Xcel Energy's Harrington Station Unit 3

Phase 1: Top-Down Analysis

Report for Public Review

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Executive Summary

Over the past few years, the forecast for renewable energy, particularly power generated from wind, has become increasingly sunny. As the demand for wind power grows, it is essential to understand the impact, both economically and physically, of integrating more and more wind into the generation mix.

Xcel Energy, one of the nation's largest utilities, owns a fleet of coal, gas, nuclear, hydro, and wind plants that it must operate economically and dispatch efficiently to meet system load demand requirements. The company began introducing wind power into its generation mix in 2000 and plans to bring 7400 MW of wind resources online by 2020.

By 2013, Xcel Energy predicts that the additional MWs generated by wind and introduced into their portfolio will dramatically change the way power must be dispatched and will increase cycling of existing plants. Such increased cycling will lead to greater wear and tear on the plants from load changes and startup-shutdown cycles and will lead to more forced outages. The objective of this paper, reporting on Phase 1 of a three-part study, is to evaluate the impact of cycling due to wind by first establishing an operational cost baseline for Xcel's Harrington Unit 3 plant. In Phases 2 and 3 of the study, modeling will be used to compare the baseline with the projected future costs of adding wind-generated electricity to the grid.

Background: To understand the impact of integrating "unmanaged" wind power into Xcel Energy's system, one must understand the basic structure of an electricity "grid." An electricity system, from fuel source to end user, is one of the most complex, interconnected systems in the world and it must be carefully managed and maintained to prevent surges, sags, brownouts and blackouts.

The grid is essentially a complex highway system with electrons constantly merging onto and exiting off the road. The laws of

Generation mix
The combination of different types of power plants used to meet electricity demand

Dispatch
The addition or subtraction of output to or from the grid

Cycling
The process of bringing plants on and offline or increasing and decreasing unit output to meet load demand

Forced outage
When a unit has to be taken off the grid due to equipment problems

Surge, sag, brownout, blackout
Disruptions on the grid when supply is not balanced with demand

physics dictate that the grid must operate in a steady, balanced state in order to maintain stability. In order to maintain the grid in a steady and balanced state, grid operators constantly bring electrons onto and remove them from the system so that supply precisely matches demand.

To extend the analogy, when the system does not operate in a steady and balanced state, it is similar to when too many cars (a surge) or too few cars (a sag) are on the highway. In such situations, the end user may experience disruptions due to the imbalance.

The problem grid operators face when integrating large amounts of unmanaged wind into the system is that electricity generated by wind is intermittent and volatile. That is, the wind doesn't blow at a steady state 24/7, so electricity isn't generated at a constant rate.

Integrating intermittent, volatile electricity into the grid can cause a surge or a sag that can lead to brownouts or blackouts. So grid operators, like Xcel Energy, must balance the wind-generated electricity with electricity online, ready and available to the system. In order to do that, plants that are already operating and connected to the grid must suddenly and rapidly increase or decrease their output to maintain balance. In some cases, this means that plants that are offline must be brought online quickly. The rapid starts and stops or increases and decreases in output are called "cycling."

Engineers predict and manage the generation and dispatch of electrons to the grid by relying on a combination of cycling semi-flexible baseload plants, and starting and stopping intermediate and peaking plants. Baseload plants, like Xcel Energy's Harrington plant, operate 24/7, intermediate plants are brought online to meet daytime demand, and peaking plants are brought online usually for only a few hours at a time, for example, to power everyone's air conditioners when the temperatures dictate.

Baseload plants are usually designed to run with a minimum number of cycling events—starts and stops and load changes (i.e. changes in output). Changes to the way the plant operates will impact the wear and tear on the machinery in the plant. For instance, the alloy steel blades in a turbine or the steam drum in a boiler suffer metal fatigue, deformation and degradation when thermal conditions change rapidly or frequently, as they do during cycling events.

Returning to the car analogy, damage from cycling a power plant more than the design allows is like the quick, regular acceleration of a car's engine before it is warmed up on cold days. Both can cause

Baseload plant
An energy plant devoted to the production of all of a given region's continuous energy demand, and produce energy at a constant rate, usually at a low cost relative to other production facilities available to the system.

24/7
When a unit runs 24 hours a day, seven days a week

Hot, warm, cold starts
Determined by the metal temperature of the boiler and turbine when the start is initiated

Load changes
Changes in unit load output including hot, warm, and cold starts; trips; shutdowns; load follows, and Automatic Generation Control

significant metallurgical degradation.

When significant amounts of unmanaged wind-generated electricity are introduced into the system, cycling events will increase at baseload plants like Harrington. As the frequency and type of cycling operations (hot, warm and cold starts or load following) impact the wear and tear of the plant, they will also, consequently, impact the cost to operate and maintain the plant.

The Study: Integrating additional unmanaged wind power into Xcel Energy's generation mix, therefore, is expected to significantly impact the cost of maintaining the integrity of the overall fleet. To this end, Xcel Energy asked APTECH Engineering Services to conduct a Cost of Cycling Analysis on three of its power plant units.

The purpose of the study is to quantify the increase in capital, and operation & maintenance costs (including fuel costs) for the three plants. The plants included in the study are:

- Pawnee Plant Unit #1 (Pawnee 1) - Colorado
- Harrington Plant Unit #3 (Harrington 3) - Texas
- Sherburne County Unit #2 (SherCo 2) - Minnesota.

For each unit, the study was broken down into three phases:

- Phase 1 — a top-down analysis using a statistical approach and baseline historical data.
- Phase 2 — an analysis of the change in future costs from the established baseline assuming a different, but specified, future load profile.
- Phase 3 — the detailed engineering "bottom-up" analysis of critical plant components and recommendations.

All three phases of the Pawnee Station study have been completed and a series of three reports were submitted by APTECH to Xcel Energy. This report is the "Public Review" version of the detailed proprietary report submitted to Xcel energy outlining the results from Phase 1 of the Harrington Station Unit #3 (Harrington 3) study.

The Phase 3 detailed companion report discusses excessive damage-related problems found during a cycling analysis of plant engineering data, but does not include details of the methodology APTECH used to derive cycling costs. (The proprietary version of the report may be made available to selected parties under a Non-Disclosure Agreement.) This report also provides cost saving recommendations for the future. The study did not, however, evaluate the causes of increased cycling events that

System load
The amount of megawatts going into and out of the grid at any given time

Load following
When a unit moves up or down in load to meet grid-dispatch demands

Load profile
The pattern of output characteristic of a particular unit or plant

have occurred previously.

The report is divided into three sections: 1) this executive summary providing a brief overview of the project scope and technical approach, 2) an introduction and presentation of APTECH'S unit damage modeling for the period 1997—2nd quarter 2008, and 3) presentation of top-down cycling cost analysis.

The Data: Tables 1—4 provide a summary of APTECH's best estimates of the total cost of cycling for Harrington 3 for the year 2000, the baseline year. Prior to 2001, the unit was base loaded at a high capacity factor which means that the unit ran at 80 %—or higher—unit capability factor (or 24/7) for a high percentage of the hours in the year. During the baseline year, there was little or no wind generated power (non-dispatchable power) coming into the Southwestern Public Service (SPS, part of Xcel) system.

In the Phase 2 report, these historical, baseline results will be compared with the forecast cost results for a future year during which significant wind generated power will be integrated into the system. It is at that time that the cycles per year are expected to increase due to the addition of wind power.

The total cost of cycling analysis examines nine different cost factors. The composite of these factors (E1— E9) are then totaled to determine the cost of each type of cycle (hot start, warm start, cold start, and significant load follows). In these studies, a significant load follow is defined as a load change that results in a substantial amount of wear and tear according to APTECH's Loads Model. Therefore, small load changes are not considered significant and are not considered in this study.

Significant Findings: Of the nine cost factors, wear and tear costs were the highest. For example, Table 1 shows that the largest element was for hot start-shutdown cycles was the cost of maintenance at $23.3k (thousand) per start. The second highest cost was start-up fuel at $15.6k closely followed by the cost of capital maintenance at $15.4k per cycle.

For Table 1, a cycle is considered a start-stop cycle that is a weighted average based on the documented hot starts from Harrington 3 for the year 2000.

All costs in Tables 1 - 4 are given in 2008 dollars. The baseline data is also expressed in dollars per MWh of generation. This was based on net generation during the year 2000.

Capacity factor
A rating that indicates what percentage of the time a plant will run during a particular period — derived by dividing the output of a unit and the amount of time it runs by the total number of hours during the period

MWh
The megawatt output of a unit when it runs for one hour

Table 1 -- Cost elements for Hot –Start Shutdown Cycles at Harrington Station Unit 3

Cost elements for HOT Shutdown-Start Cycles at Harrington Unit 3
(based on CY 2000 Cycles in 2008 dollars)
Hot starts in 2000-20082Q had average peak ramp rate of 152 MW per hour

	Baseline Data ($K/ cycle) [1]			Baseline Data ($/ 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	$12.6K	$3.1K	$22.1K	$0.010	$0.002	$0.017
E2: Cost of maintenance - includes maintenance and overhaul maintenance expenditures for boiler, turbine, generator, air quality control systems and balance of plant key components	$52.5K	$28.6K	$71.9K	$0.040	$0.022	$0.055
E3: Cost of capital maintenance - includes overhaul capital maintenance expenditures for boiler, turbine, generator, air quality control systems and balance of plant key components	$34.8K	$15.3K	$50.5K	$0.027	$0.012	$0.039
E4: Cost of forced outage and derate effects, including forced outage time, replacement energy, and capacity.	$10.7K	$7.2K	$13.5K	$0.008	$0.005	$0.010
E5: Cost of long-term heat rate change due to cycling wear and tear [3]	$0.0K	$0.0K	$0.0K	$0.000	$0.000	$0.000
E6: Cost of heat rate change due to low load and variable load operation (process related)	$3.6K	$2.7K	$4.7K	$0.003	$0.002	$0.004
E7: Cost of startup auxiliary power	$0.5K	$0.5K	$1.3K	$0.000	$0.000	$0.001
E8: Cost of startup fuel	$15.6K	$6.3K	$16.4K	$0.012	$0.005	$0.013
E9: Cost of startup (Operations – chemicals, water, additive, etc.)	$1.3K	$1.0K	$1.6K	$0.001	$0.001	$0.001
Total incremental cost of cycling (sum of E1 through E9)	$131.5K	$97.8K	$158.4K	$0.101	$0.075	$0.122

[1] Cost data refer to top down results for CY 2000, including fatigue-creep interaction effects and adjusted for signature data
[2] based on all analyzed hot starts and 2,602 net GWh during CY 2000
[3] Over the last decade, maintenance and other activities have prevented significant heat rate increases
Note: Total best estimate = sum of individual ones; but this is not true of high and low totals

Table 2 -- Cost elements for WARM Shutdown-Start Cycles at Harrington Unit 3

Cost elements for WARM Shutdown-Start Cycles at Harrington Unit 3
(based on CY 2000 Cycles in 2008 dollars)
Warm starts in 2000-20082Q had average peak ramp rate of 102 MW per hour

	Baseline Data ($K/ cycle) [1]			Baseline Data ($/ 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	$15.8K	$3.9K	$32.3K	$0.012	$0.003	$0.025
E2: Cost of maintenance - includes maintenance and overhaul maintenance expenditures for boiler, turbine, generator, air quality control systems and balance of plant key components	$65.9K	$40.6K	$99.6K	$0.051	$0.031	$0.077
E3: Cost of capital maintenance - includes overhaul capital maintenance expenditures for boiler, turbine, generator, air quality control systems and balance of plant key components	$43.6K	$23.0K	$71.0K	$0.034	$0.018	$0.055
E4: Cost of forced outage and derate effects, including forced outage time, replacement energy, and capacity.	$13.4K	$9.7K	$18.3K	$0.010	$0.007	$0.014
E5: Cost of long-term heat rate change due to cycling wear and tear [3]	$0.0K	$0.0K	$0.0K	$0.000	$0.000	$0.000
E6: Cost of heat rate change due to low load and variable load operation (process related)	$4.0K	$3.0K	$5.3K	$0.003	$0.002	$0.004
E7: Cost of startup auxiliary power	$1.0K	$0.8K	$1.3K	$0.001	$0.001	$0.001
E8: Cost of startup fuel	$21.7K	$15.2K	$24.9K	$0.017	$0.012	$0.019
E9: Cost of startup (Operations – chemicals, water, additive, etc.)	$1.9K	$1.5K	$2.4K	$0.001	$0.001	$0.002
Total incremental cost of cycling (sum of E1 through E9)	$167.2K	$131.8K	$214.1K	$0.129	$0.101	$0.165

[1] Cost data refer to top down results for CY 2000, including fatigue-creep interaction effects and adjusted for signature data
[2] based on all analyzed warm starts and 2,602 net GWf during CY 2000
[3] Over the last decade, maintenance and other activities have prevented significant heat rate increases

Note: Total best estimate = sum of individual ones; but this is not true of high and low totals

Table 3 -- Cost elements for Cold Start – Shutdown Cycles at Harrington Station Unit 3 (Based on CY 2000 in current (2008) dollars)

Cost elements for COLD Shutdown-Start Cycles at Harrington Unit 3

(based on CY 2000 Cycles in 2008 dollars)
Cold starts in 2000-20082Q had average peak ramp rate of 140 MW per hour

	Baseline Data ($K/ cycle) [1]			Baseline Data ($/ 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	$28.8K	$7.2K	$42.7K	$0.011	$0.003	$0.016
E2: Cost of maintenance - includes maintenance and overhaul maintenance expenditures for boiler, turbine, generator, air quality control systems and balance of plant key components	$120.1K	$63.9K	$148.4K	$0.046	$0.025	$0.057
E3: Cost of capital maintenance - includes overhaul capital maintenance expenditures for boiler, turbine, generator, air quality control systems and balance of plant key components	$79.5K	$33.7K	$102.5K	$0.031	$0.013	$0.039
E4: Cost of forced outage and derate effects, including forced outage time, replacement energy, and capacity.	$24.4K	$16.1K	$28.6K	$0.009	$0.006	$0.011
E5: Cost of long-term heat rate change due to cycling wear and tear [3]	$0.0K	$0.0K	$0.0K	$0.000	$0.000	$0.000
E6: Cost of heat rate change due to low load and variable load operation (process related)	$4.3K	$3.3K	$5.8K	$0.002	$0.001	$0.002
E7: Cost of startup auxiliary power	$2.5K	$2.0K	$3.1K	$0.001	$0.001	$0.001
E8: Cost of startup fuel	$31.1K	$21.8K	$35.7K	$0.012	$0.008	$0.014
E9: Cost of startup (Operations – chemicals, water, additive, etc.)	$3.2K	$2.6K	$4.0K	$0.001	$0.001	$0.002
Total incremental cost of cycling (sum of E1 through E9)	$293.9K	$217.2K	$333.5K	$0.113	$0.083	$0.128

[1] Cost data refer to top down results for CY 2000, including fatigue-creep interaction effects and adjusted for signature data
[2] based on all analyzed cold starts and 2,602 net GWh during CY 2000
[3] Over the last decade, maintenance and other activities have prevented significant heat rate increases

Note: Total best estimate = sum of individual ones; but this is not true of high and low totals

Table 4 -- Cost elements for Significant Load Follows at Harrington Station Unit 3 (Based on CY 2000 in current (2008) dollars)

Cost elements for Most Significant Load Follow Cycles (SLFs) at Harrington Unit 3

(based on CY 2000 Cycles in 2008 dollars)

	Baseline Data ($K/ cycle) [1]	-	-	Baseline Data ($/ 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	$0.25K	$0.06K	$0.79K	$0.0016	$0.0004	$0.0049
E2: Cost of maintenance - includes maintenance and overhaul maintenance expenditures for boiler, turbine, generator, air quality control systems and balance of plant key components	$1.05K	$0.29K	$2.15K	$0.0065	$0.0018	$0.0132
E3: Cost of capital maintenance - includes overhaul capital maintenance expenditures for boiler, turbine, generator, air quality control systems and balance of plant key components	$0.70K	$0.17K	$1.59K	$0.0043	$0.0011	$0.0098
E4: Cost of forced outage and derate effects, including forced outage time, replacement energy, and capacity.	$0.21K	$0.10K	$0.37K	$0.0013	$0.0006	$0.0023
E5: Cost of long-term heat rate change due to cycling wear and tear [3]	$0.00K	$0.00K	$0.00K	$0.0000	$0.0000	$0.0000
E6: Cost of heat rate change due to low load and variable load operation (process related)	$0.12K	$0.07K	$0.19K	$0.0007	$0.0004	$0.0012
E7: Cost of startup auxiliary power	$0.00K	$0.00K	$0.00K	$0.0000	$0.0000	$0.0000
E8: Cost of startup fuel for mill starts	$0.00K	$0.00K	$0.00K	$0.0000	$0.0000	$0.0000
E9: Cost of startup (Operations – chemicals, water, additive, etc.)	$0.00K	$0.00K	$0.00K	$0.0000	$0.0000	$0.0000
Total incremental cost of cycling (sum of E1 through E9)	$2.33K	$1.38K	$3.85K	$0.0143	$0.0085	$0.0237

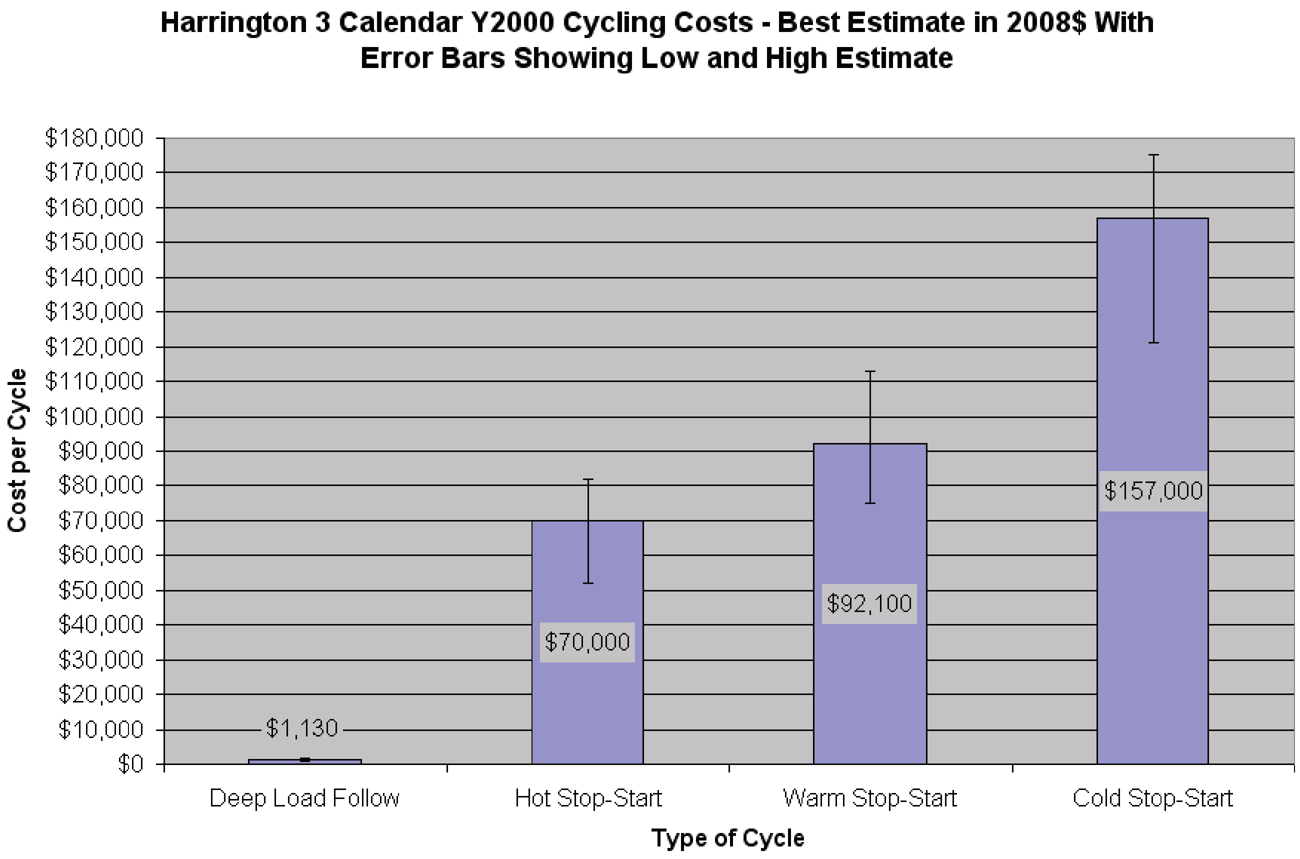
[1] Cost data refer to top down results for CY 2000, including fatigue-creep interaction effects and adjusted for signature data

[2] based on all analyzed significant LFs and 2,602 net GWh during CY 2000

[3] Over the last decade, maintenance and other activities have prevented significant heat rate increases

Note: Total best estimate = sum of individual ones; but this is not true of high and low totals

FIGURE 1 – Harrington 3 Calendar Year 2000 Cycling Cost Estimates



Section 1– Introduction

Background and Objectives: Xcel Energy, Inc. is a major U.S. electric and natural gas company with headquarters in Minneapolis, Minnesota. Operating in eight Western and Midwestern states, Xcel Energy provides a comprehensive portfolio of energy-related products and services to 3.3 million electricity customers and 1.8 million natural gas customers.

With a total of 16,042 MW of generating capacity, Xcel Energy manages resources including nuclear, coal, gas, biomass, hydro, purchased power, and 1,000 MW of wind power. Wind power was first introduced into the generation mix in 2000.

In 2007, Minnesota[1] and Colorado[2], two of the states in which Xcel Energy operates, established state requirements to increase the renewable energy mix in electricity sales. Minnesota's renewable energy objective requires Xcel Energy to acquire 30% of its energy from renewable resources by 2020—including 25% from wind—while Colorado's law establishes the state's renewable energy requirement at 20% by 2020.

To meet the specific requirements of the Minnesota law, Xcel Energy will increase its current wind nameplate plant capacity from 1,000MW to a total 3,800 - 4,000 MW. It is expected that increased penetration of wind into Xcel Energy's portfolio will change the daily load profiles of their plants with increased cycling (including more starts and more and deeper load follows) and at reduced capacity.

In order to quantify the impact of adding more wind into their portfolio, Xcel Energy engaged APTECH Engineering Services to estimate the costs to cycle the Pawnee (Pawnee 1), Harrington Unit #3 (Harrington 3) and Sherburne County Plant Unit #2 (SherCo 2).

The assessment for each unit occurred in three phases. This Report for Public Review summarizes APTECH's work on the results of Phase 1 for Harrington 3. Reports for Phase 2 and 3 will be issued at a later date for Harrington 3, as will the results of the analyses for Pawnee and SherCo.

The purpose of the study is to quantify the increase in capital and operating costs (including fuel and O&M) of several major Xcel Energy-owned units (listed above) due to increased cyclic operation. The study assesses the additional wear and tear damage cost for load cycling at both current cycling operation and under future operational scenarios. The study

[1] **Minnesota Statute 216B.1691**
Renewable Energy Objectives – 30% of Retail electric energy sales in Minnesota generated from renewables (Kw-hr)

[2] **Colorado Code of Regulations – 4CCR 723-3, Section 3662**
Renewable Energy Standard (20% of Retail Electric Sales by 2020)

Nameplate capacity
The output of a unit for which it was originally designed

also identifies excessive damage-related problems found analyzing plant data collected, and provides cost saving recommendations.

Phase 1 provides a top-down analysis using a statistical approach based on baseline historical data. In this phase, APTECH determined the relationship between cycling operations (hot starts, warm starts, cold starts, shutdowns, load changes) and costs (capital, operations, maintenance, etc.) using the current plant configuration and historical operations and financial data. Baseline costs were then established for the unit-based cycling operations before the introduction of wind energy.

Phase 2 is an analysis of the forecasted changes in future costs derived from a comparison to the established baseline. A different, but specified, load profile is assumed but no other changes or countermeasures are applied to the model. Phase 3 is a bottom-up analysis which uses a detailed engineering approach. In Phase 3, a cost analysis is performed at the component level, and provides recommended countermeasures and a list of suggested recommendations.

Harrington 3 Plant Profile: Harrington 3 is a 360 MW (gross) coal-fired steam-electric generating unit. It is the newest of three units at the station which is located northeast of Amarillo, Texas. The Harrington plant was the first modern coal-fired plant brought into the Southwestern Public Service Company system (a predecessor of Xcel Energy). Unit 3 started operating in 1980.

The boiler is a Combustion Engineering controlled-circulation type unit that burns pulverized coal (Powder River Basin Sub-bituminous) with natural gas igniters. The boiler has 20 tilting tangential low NOx burners. The boiler was specified to deliver superheated steam at 2,620 psi and 1005°F and reheated steam at 542 psi and 1,005°F.

The plant boiler water chemistry is All-Volatile Treatment (AVT) with ammonia for alkalinity (PH) control. The flue gas emissions controls include a baghouse, and the unit has three high pressure (HP) feedwater heaters, one deaerator, and four low pressure (LP) feedwater heaters. Steam from the boiler is sent to a General Electric turbine. The turbine is a two-cylinder tandem compound machine with double exhaust and a condensing reheat turbine. It was retrofitted with a ruggedized LP rotor. The water and hydrogen cooled generator set runs at 3600 rpm and a rated output of 346749 KW.

APTECH's Approach to Estimating Cycling Costs: Cost-of-cycling estimates are, by their nature, not precise. This is

because the cycling damage mechanisms leading to component failures are very complex and usually involve multi-year time dependent degradation phenomena.

APTECH first began working on this problem over 15 years ago. Over time, the detailed and often expensive analyses developed into a more top down, multi-faceted approach that provides more thorough cycling cost estimates at a reduced and reasonable cost.

APTECH's approach uses multiple methods to derive and bound cycling cost estimates so that results can be validated. Figure 1-1 shows a simplified flowchart of this approach. APTECH has used this methodology for hundreds of generation units owned by utility clients around the world.

APTECH's approach utilizes unit/plant-specific information, industry data, as well as extensive experience evaluating similar units. The methodology relies on two primary parallel approaches to analyzing cycling-related costs: (1) top-down analyses using plant composite damage accumulation models and statistical methods; and (2) modified bottom-up component-level studies using real-time monitoring data at key equipment locations, prior engineering assessments of critical components, and surveys of plant personnel. This document reports the findings of the Phase 1 top-down analyses.

To execute the top-down analysis, we used historical cost data for Harrington 3. Further, we used data and results from similar top-down cycling cost studies we have done on many other coal units similar to Harrington 3.

What makes APTECH's methodology especially powerful is the ability of our top-down approach to capture the effects of operator error and other more 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 in Phase 3 of the project.

Detailed descriptions of the top-down approach used by APTECH, and the results of these analyses are presented in Section 2 of this report.

Load cycling

Changes in unit load output including hot, warm, and cold starts; trips; shutdowns; load follows, and Automatic Generation Control

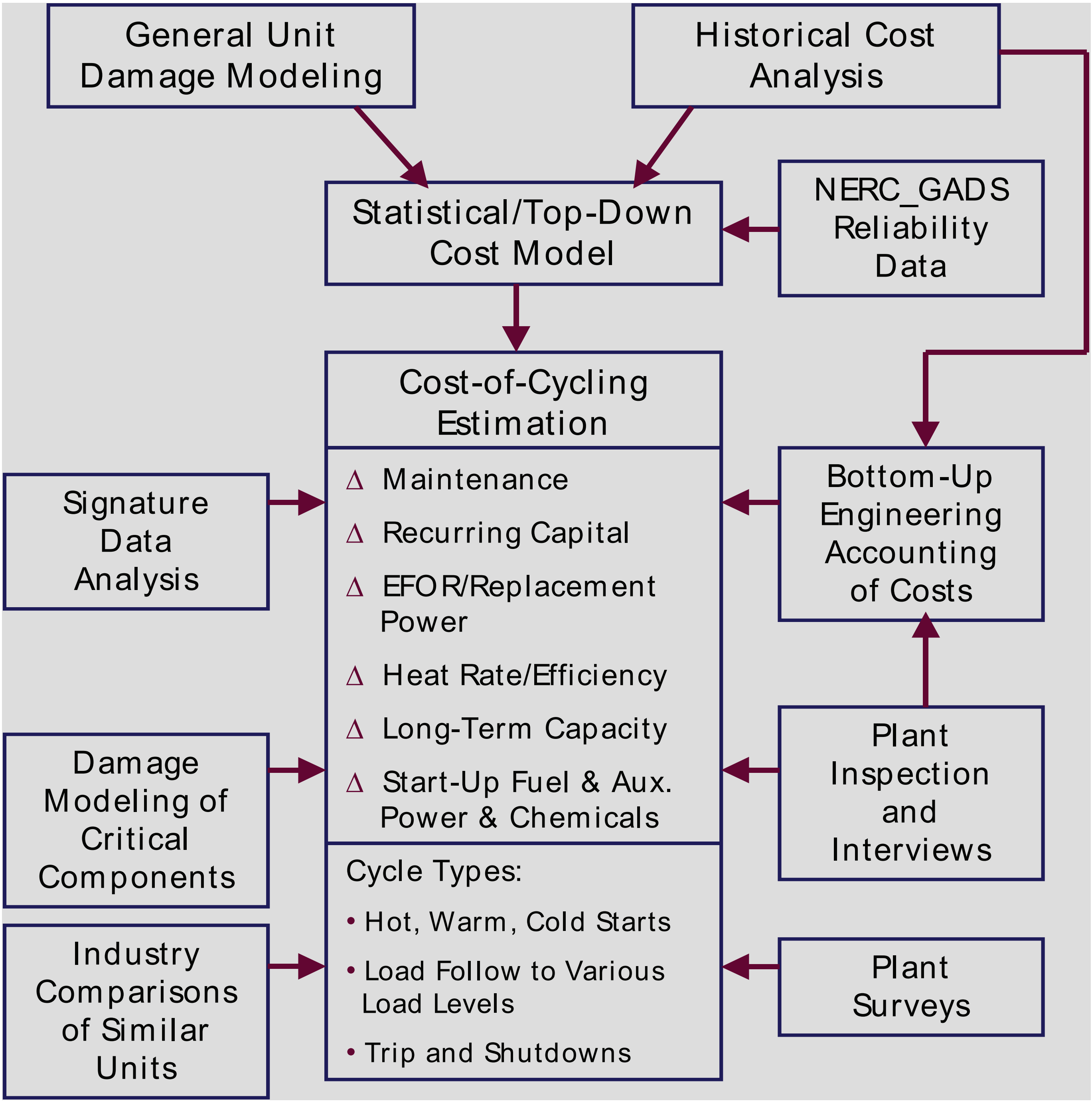


Figure 1-1 — Cost of Cycling Estimation Procedure

Section 2– The Top-Down Methodolgy

APTECH's experience shows that reasonably accurate estimates of total unit cycling costs can be derived using commonly accepted statistical analysis methods. The analysis looks at 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, and load follows). This section briefly describes the various aspects of APTECH's top-down cycling cost methodology.

2.1—DAMAGE MODELING

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., pressure, temperature, strain, and heat flux), with state-of-the-art stress analyses and damage algorithms. The end result is 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, and would still be subject to the uncertainties of component life analysis. To limit the cost of analyzing all the critical components in the unit and to improve the accuracy of cost estimates, a general damage resources model is preferred.

The model used in this study, developed by APTECH, is intended to provide information on the cycling-related damage for the entire unit. It is based on physical models and uses plant temperatures and other data to provide cross-validation with output changes, and, importantly, it requires only hourly MW "loads" data to estimate damage. Relying solely on hourly MW unit load data is an inherent advantage because hourly MW data provide an accurate history of past unit operations and these types of data are more readily available.

Note: In this section of the report, the term "loads" refers to the MW output of the unit, not forces, moments, or temperatures.

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

The damage model (and the economic models described below) has been calibrated several different ways. The two most important methods are:

1. **Predicting later cycling costs from earlier cycling costs.** Benchmarking studies have been performed in which the top-down model predicts 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 predict future costs with reasonable accuracy.

2. **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 these 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 then 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 and these analyses.

Damage Model Results and Operational Histories: The general damage model (APTECH's Loads Model) was applied to every hour of actual MW data for most of the years 1997 through 2Q 2008 for Harrington 3. Results are given in the following tables and figures:

- Table 2-1 gives the resulting quarterly damage estimates from the Loads Model in equivalent hot starts (EHS) per quarter for Harrington 3.
- Figure 2-1 shows this same information in graphical format.
- Figure 2-2 shows total number of actual starts in each quarter with hourly MW data from 1997 through the second quarter of 2008.
- Figure 2-3 plots all of the hourly MW data from the EPA web site that contained Harrington 3 data from 1997 to 2Q 2008.
- Figure 2-4 provides histograms of the three Harrington Units' hourly MW output from 1997 through 2Q 2008. In these plots it is easy to observe that these units do not often shutdown and start, with little time at minimum load.

Using the hourly MW data for the years

Note

The primary data sources for our Loads Model analyses were the U. S. EPA data from 1997 through 2Q 2008.

Equivalent Hot Starts (EHS)

APTECH's standard unit of damages

1982 through 2007, we also used the damage model to determine the relative wear and tear damage of "typical" hot, warm, and cold start cycles of Harrington 3 in relation to our normalized damage parameter, Equivalent Hot Starts (EHS). The total cycling damage from typical hot, warm and cold starts for Harrington units 1 - 3 and Pawnee 1 for comparison are summarized in Table 2-2, along with their typical MWh ramp rates.

Table 2-3 shows the computed relative damage of load following cycles for Harrington 1 – 3 and Pawnee 1, which are typical of most other similar units we've studied.

The damage figures for Harrington 3 in Tables 2-2 and 2-3 are relatively low compared to other similar units we have analyzed. The damage would be higher but for the very low annual starts and relatively infrequent load follows and high minimum loads.

2.2—STATISTICAL REGRESSION ON DAMAGE COSTS

APTECH has developed an equation that defines the incremental total cost of cycling as the sum of the following five distinct elements:

1. Increases in maintenance, operation (excluding fixed costs), and overhaul capital expenditures
2. Increased time-averaged replacement energy and capacity cost due to increased equivalent forced outage rates (EFOR)
3. Increase in the cost of heat rate changes due to low load and variable load operation
4. Increase in the cost of consumed startup fuel, auxiliary power, chemicals, water, and extra manpower for startups
5. Cost of long-term heat rate increases (i.e., efficiency loss)

To estimate the "wear and tear" costs of items 1 and 2 listed above, APTECH'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 statistical 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.

Cost and Equivalent Forced Outage Rate Data Sources: APTECH obtained detailed, comprehensive capital, maintenance, and operations (C+O&M) cost data for Harrington 3 for the years 1996 through 3Q 2008 from Xcel Energy staff. We also obtained plant-wide EIA (Energy Information Administration) Form 1 cost data for the earlier

Normalized damage parameter
A parameter that allows all cycling impacts to be compared on an equivalent "apples to apples" basis

Replacement energy
Energy that has to be purchased or found elsewhere to make up for energy lost from the unit in question

Heat Rate
The efficiency of the unit based on energy input (fuel) and electricity output at the generator

Auxiliary power
That percentage of unit output that is consumed inside the plant to run equipment

Startup fuel
Premium fuel (natural gas or oil) that is burned before the coal is actually fed to the burner— also known as warmup fuel

years of the plant, but found that data to be poorly screened so they were used in a limited way as a rough check on the more recent data. The available cost data from Xcel Energy was more than adequate for our analyses.

APTECH staff manually screened the cost data by throwing out all costs that are clearly not related to cycling from statistical consideration. These typically include base O&M, fixed staff salaries and benefits, buildings and grounds maintenance, plant security costs, and large environmental emissions projects. The remaining unscreened costs are then included in our top-down statistical model, which itself further screens out non-cycling-related costs.

Examples of non-cycling related plant equipment costs include 1) most pulverizer maintenance which is erosion related though some pulverizer maintenance is related to wear and tear damage incurred during start up, shutdown, and low load follows; and 2) boiler tube erosion costs.

The Equivalent Forced Outage Rate (EFOR) data for this unit were available for 1982 to 2007 directly from the NERC-GADS database we received from NERC. Figure 2-5 graphically presents the EFOR history of Harrington 3. APTECH's top-down method simply uses the annual equivalent forced outage hours (EFOH) based on the EFOR values provided in that database.

The Basic Regression Approach: The underlying premise of the statistical regression approach (a common form of statistical analysis) is that cycling directly causes a significant proportion of the annual non-fuel unit costs. The independent cycling-related variable was taken to be annual EHS (the normalized damage parameter), e_i, where "i" represents a calendar year for which enough historical MW load and cost data for each unit were provided to run the regression fit procedure. This annual measure of cycling damage, EHS, was estimated from the general damage model described earlier.

As detailed earlier, APTECH first screens total costs to eliminate only those that bear no relation to unit loading, like buildings and grounds expenses. Costs remaining after this initial screen are called "candidate" costs. Therefore, the dependent variable was an estimate of annual candidate cost "C". This variable represented the total candidate annual capital, maintenance, and forced outage cost, independent of whether the cost was actually due to cycling or not. The proportion of C associated with cycling was then estimated from the regression method.

Equation for Annual Costs: Total cost (C), was taken to include two key compo-

Equivalent Forced Outage Rate (EFOR)
An indication of a unit's reliability when it was called upon to operate

NERC-GADS
North American Electricity Reliability Corporation—Generation Availability Database System. An industry clearinghouse of reported data concerning the performance of power plants

Candidate costs
Variable C—costs that remain after the initial screening

nents affected by cycling: 1) maintenance; and 2) forced outage costs. Maintenance cost was modeled by starting with plant financial cost data, adjusting for inflation, and smoothing the data.

In all, there are nine coefficients used to relate costs to the "EHS," and several regression constraints used to limit the relative costs of the three terms to reasonable ranges. In this way, the regression covered both: (1) cumulative generation and, thus, accumulated cycling damage from installation year to the current year, and (2) more immediate annual damage over the most recent years.

Cost per Equivalent Hot Start: The final desired result was the cost of a single hot start in the context of all the parameters that affect cycling. Once the coefficients were determined by fitting historical cycling and cost data, this cost was calculated by taking the derivative of the annual cycling cost equation with respect to EHS.

Accounting for Uncertainty: There will, of course, always be uncertainty in the statistical regression methodology. Uncertainty occurs for various reasons, including:

- Limited sample size
- Noise or random error inherent in variations of annual cost and cycling characteristics
- Both standard and computer-based numerical procedures

Results of Top-Down Statistical Regression: The statistical models described above were used to develop best estimates of the total unit equipment damage costs due to cycling, which include incremental EFOR, capital, and maintenance costs. These costs are first estimated for an EHS, and then estimated for the typical cycles experienced by Harrington 3, as described below.

Figure 2-6 shows the results of this analysis and the resulting best estimate of $48,500 per EHS. We then performed a statistical uncertainty analysis to establish upper and lower bounds. Figures 2-7 and 2-8 show the regression fits for the upper and lower bounds, resulting in $57,000 per EHS and $39,300 per EHS, respectively. We will compare this estimate to the estimate independently derived in our bottom up analysis in Phase 3 of the project.

Estimates of Harrington 3 Typical Cycle Costs: The previous section provides cycling cost estimates for EHS, APTECH's normalized damage parameter. The actual damage accumulated per typical hot, warm, and cold start is a function of how Harrington 3 is operated during the cycles.

APTECH studied the typical MW ramp rates and the temperature ranges and thermal-ramp rates at key points to assess relative damage between cycle types, and between Harrington 3 and other comparable units APTECH has studied. Tables 2-4a through 2-4d (pages 2-13 through 2-16) illustrate APTECH's best estimates, along with upper and lower bounds for typical hot, warm, and cold starts and load follow cycles.

2.3—STATISTICAL REGRESSION ON HEAT RATE IMPACTS AND COSTS

The effect of cycling on heat rate and coal costs was investigated for Harrington 3. The investigation included hourly coal and natural gas burn and MW generated data for Harrington 3 obtained from the EPA[3] website covering 1997 through 1Q 2008.

Data Processing and Basic Heat Rate Results:

Hourly Data: Figure 2-9 summarizes the results of the hourly coal burn analysis for Harrington 3. In this plot, the green points show all actual hourly data, excluding data near zero hourly MW and a few outliers.[4] The red data points are curve fits using an advanced nonlinear regression tool.[5] The reason the red points do not lie on a single heat rate vs. hourly MW curve, and why they model much of the variability inherent in the green data points, is because they are fit to many other independent variables including:

- All hourly MW readings above 20 MW
- Each month of the year (individually) to model seasonal effects
- Calendar year to model aging and other long-term changes
- Number of starts (0, 1, or 2) each day
- Number of daily shutdowns

The MW and calendar age variables above are each fit using a mathematical technique called nonlinear polynomials with four coefficients. The other variables are handled using linear terms.

The average "fit error" of these highly scattered hourly readings is about 7% and was 8% before outlier removal. These are acceptable results for hourly EPA data for coal units.

Also, the regression "explained" about half of the large hourly heat rate variations (green points) in Figure 2-9. More would be explained if our outlier screening had been more aggressive.

Monthly Data The monthly "raw" average heat rates for Harrington 3 were rela-

Ramp rate
The rate of change of the output over time during a cycling event

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[3] The site link is ftp://ftp.epa.gov/dmdnload/emissions/hourly/

[4] Using APTECH's proprietary screening algorithm, the data were lightly screened and had less than 0.5% of hourly readings removed as outliers; an acceptably low percentage based on previous studies using EPA hourly data for coal units.

[5] The "multivariable fractional polynomial (mfp)" model was implemented using computer program Stata, "a … statistical package designed for researchers of all disciplines." See http://www.stata.com .

tively steady with some modest improvements over time.

Heat Rate Effects:

Seasonal Effects Controlling for all the other independent variables listed above, the 1997 to 1Q2008 month-to-month heat rate differences are statistically significant but unremarkable. January had the lowest heat rates. The May through July summer heat rates were about 3% larger than those in January.

Immediate Cycling Effects As listed above, daily starts and shutdowns were explicitly included in the nonlinear regression model of heat rate, again while properly accounting for all the other listed heat rate effects including MW itself. Specifically, our best estimate of the extra daily fuel burn from a start and shutdown was 2580 million Btu of fuel energy.

Using the most recently provided XCEL/Harrington 3 constant fuel price of approximately $1.30/million Btu for CY2008, the rounded immediate fuel cost of the cycle is estimated to be $3,400 (owing to heat rate effects). To account approximately for the statistical uncertainties, we have estimated bounds of $2,500 and $4,500.

The difference in *startup* fuel costs among hot, warm, and cold starts are quite large, but the differences among the start types in heat rate effects are usually not. In this analysis, there are not enough data to differentiate the immediate heat rate costs of hot, warm, and cold starts, so these relatively small heat rate-based cost estimates above are applied to all shutdown-start cycles, with only a small adjustment for shutdown length in Table 2-4. Tables 1 through 3 in the Executive Summary cover starts in CY 2000 (in 2008 dollars), so they account for the earlier coal cost and inflation.

Table 2-1 LOADS MODEL QUARTERLY DATA FOR Harrington #3 1997 through 2Q 2008

quarter	ehs	od	ehsperod	zd	hs	ws	cs	lf	orat	pd	md	starts
1Q97	22.2	88.3	.252	1.7	2	1	0	0	0	90	0	3
2Q97	11.9	90.2	.191	.8	0	1	0	3	0	91	0	1
3Q97	14.7	80	.189	12	0	1	0	1	0	92	0	1
4Q97	18	71.2	.203	20.8	0	2	1	1	.08	92	0	3
1Q98	15.7	89.3	.197	.7	1	1	0	2	0	90	0	2
2Q98	21	88.3	.204	2.7	1	2	0	3	0	91	0	3
3Q98	17.7	89.7	.203	2.3	0	1	0	5	0	92	0	1
4Q98	15.4	89.9	.199	2.1	0	3	0	4	0	92	0	3
1Q99	19.9	84	.203	6	0	3	0	0	0	90	0	3
2Q99	22.1	84.4	.209	6.6	0	3	0	10	0	91	0	3
3Q99	14.4	91	.204	1	0	1	0	5	0	92	0	1
4Q99	12.9	90.4	.199	1.6	0	2	0	1	0	92	0	2
1Q00	13.2	76.9	.197	14.1	0	0	0	5	0	91	0	0
2Q00	18	67	.201	24	2	0	1	4	0	91	0	3
3Q00	14.3	89.9	.198	2.1	0	2	0	4	0	92	0	2
4Q00	13.2	92	.194	0	0	0	0	3	0	92	0	0
1Q01	12	90	.19	0	0	0	0	4	0	90	0	0
2Q01	24.2	88.1	.195	2.9	0	1	0	2	0	91	0	1
3Q01	17.2	89	.195	3	1	1	0	4	.21	92	0	2
4Q01	17.7	85.9	.196	6.1	0	3	0	3	0	92	0	3
1Q02	13.2	87.1	.194	2.9	0	1	0	4	0	90	0	1
2Q02	23.2	91	.196	0	0	1	0	4	0	91	0	1
3Q02	15.7	90.8	.195	1.2	0	1	0	3	0	92	0	1
4Q02	17.4	89.8	.195	2.2	0	2	0	7	0	92	0	2
1Q03	15.3	77.7	.195	12.3	0	2	0	3	0	90	0	2
2Q03	19.7	46.2	.2	44.8	2	3	1	4	0	91	0	6
3Q03	17.7	89.8	.2	2.2	0	2	0	6	0	92	0	2
4Q03	16.3	90.6	.199	1.4	0	0	0	7	0	92	0	0
1Q04	20.7	88.7	.201	2.3	0	3	0	6	0	91	0	3
2Q04	15.6	85	.2	6	0	1	1	3	0	91	0	2
3Q04	16.2	91.5	.199	.5	0	1	0	3	.17	92	0	1
4Q04	12.4	92	.197	0	0	0	0	3	0	92	0	0
1Q05	16.6	81.4	.197	8.6	0	0	1	3	0	90	0	1
2Q05	18.7	85.8	.198	5.2	0	3	0	7	0	91	0	3
3Q05	16.8	92	.197	0	0	0	0	22	0	92	0	0
4Q05	20.5	85.2	.199	6.8	1	0	1	4	0	92	0	2
1Q06	14.9	83.3	.198	6.7	0	1	0	4	0	90	0	1
2Q06	15.3	90	.197	1	0	2	0	7	0	91	0	2
3Q06	10.5	92	.195	0	0	0	0	3	0	92	0	0

Table 2-1 Continued

In the table note that calendar quarters with more than 10 days of missing data have been ignored—both in this and in all quarterly plots. In the table, “od” means operating days = 24 * quarterly service hours, “ehsperod” stands for cumulative (not quarterly) EHS per operating day, and “zd” = days at zero MW = 24 * quarterly offline hours, “lf” tracks quarterly load follow cycles, “orat” lists the number of days above 105% GDC. Finally, pd and md are period days and days of missing data, respectively.

Table 2-2 -- Cycling Damage from Typical Starts for Harrington Units 1 to 3 -- with Comparison to Pawnee. Based on 1997 to 3Q2008 EPA Hourly MW data

		Hot Start				Warm Start				Cold Start			
Unit	Warm Start Hours	Number in Data-base	Range (%GDC)	Ramp Rate (%/hr.)	Damage (%EHS)	Number in Data-base	Range (%GDC)	Ramp Rate (%/ hr.)	Damage (%EHS)	Number in Data-base	Range (% GDC)	Ramp Rate (%/hr.)	Damage (%EHS)
Harrington 1	9 to 104	20	94	45	130	84	96	29	114	6	100	20	114
Harrington 2	9 to 104	27	95	39	121	54	101	29	121	10	109	20	127
Harrington 3	9 to 104	19	94	42	120	57	101	28	120	10	103	39	274
Pawnee 1	24 to 120	36	93	38	110	30	103	26	104	15	104	27	169

Table 2-3 Harrington 1 - 3 and Pawnee 1Average Damage from Most Significant Load-Following Drops. Based on hourly gross MW data

Unit	Number in Database	Eff. Avg. Min. Load	Eff. Avg. Drop (% GDC)	Eff. Avg. Rate (%GDC/hr)	Damage (% EHS)
Harrington 1	341	258	28	34	5
Harrington 2	277	256	29	33	5
Harrington 3	249	243	33	29	6
Pawnee 1	279	414	22	47	4

Table 2-4a – Cost Elements for Hot Shutdown-Start for Harrington 3

Table 2-4a -- Cost elements for HOT Shutdown-Start Cycles at Harrington Unit 3
(based on CY 2008 cycles and in 2008 dollars)
Hot starts in 2000-2008 had averaged peak ramp rate of 152 MW per hour

	Baseline Data ($K/ cycle) [1]			Baseline Data ($/ 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	$13.1K	$3.3K	$23.0K	$0.014	$0.003	$0.024
E2: Cost of maintenance - includes maintenance and overhaul maintenance expenditures for boiler, turbine, generator, air quality control systems and balance of plant key components	$54.8K	$29.9K	$74.9K	$0.058	$0.031	$0.079
E3: Cost of capital maintenance - includes overhaul capital maintenance expenditures for boiler, turbine, generator, air quality control systems and balance of plant key components	$36.3K	$16.0K	$52.7K	$0.038	$0.017	$0.055
E4: Cost of forced outage and derate effects, including forced outage time, replacement energy, and capacity.	$27.1K	$18.2K	$34.3K	$0.029	$0.019	$0.036
E5: Cost of long-term heat rate change due to cycling wear and tear [3]	$0.0K	$0.0K	$0.0K	$0.000	$0.000	$0.000
E6: Cost of heat rate change due to low load and variable load operation (process related)	$3.0K	$2.3K	$4.0K	$0.003	$0.002	$0.004
E7: Cost of startup auxiliary power	$0.6K	$0.6K	$1.6K	$0.001	$0.001	$0.002
E8: Cost of startup fuel	$19.5K	$7.8K	$20.4K	$0.020	$0.008	$0.022
E9: Cost of startup (Operations – chemicals, water, additive, etc.)	$1.3K	$1.0K	$1.6K	$0.001	$0.001	$0.002
Total "incremental" cost of cycling (sum of E1 through E9)	$155.7K	$119.0K	$184.5K	$0.164	$0.125	$0.194

[1] Cost data refer to top down results for CY 2008, including fatigue-creep interaction effects and adjusted for signature data

[2] based on all analyzed hot starts and 2,851 net GWh during 7/1/07 to 6/30/08

[3] Over the last decade, maintenance and other activities have prevented significant heat rate increases

Note: Total best estimate = sum of individual ones; but this is not true of high and low totals

Table 2-4b -- Cost elements for WARM Shutdown-Start Cycles at Harrington Unit

Table 2-4b -- Cost elements for WARM Shutdown-Start Cycles at Harrington Unit 3

(based on CY 2008 cycles and in 2008 dollars)

Warm starts in 2000-2008 had averaged peak ramp rate of 102 MW per hour

	Baseline Data ($K/ cycle) [1]			Baseline Data ($/ 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	$16.5K	$4.1K	$33.7K	$0.012	$0.003	$0.024
E2: Cost of maintenance - includes maintenance and overhaul maintenance expenditures for boiler, turbine, generator, air quality control systems and balance of plant key components	$68.7K	$42.3K	$103.8K	$0.048	$0.030	$0.073
E3: Cost of capital maintenance - includes overhaul capital maintenance expenditures for boiler, turbine, generator, air quality control systems and balance of plant key components	$45.5K	$24.0K	$74.1K	$0.032	$0.017	$0.052
E4: Cost of forced outage and derate effects, including forced outage time, replacement energy, and capacity.	$34.0K	$24.5K	$46.6K	$0.024	$0.017	$0.033
E5: Cost of long-term heat rate change due to cycling wear and tear [3]	$0.0K	$0.0K	$0.0K	$0.000	$0.000	$0.000
E6: Cost of heat rate change due to low load and variable load operation (process related)	$3.4K	$2.5K	$4.5K	$0.002	$0.002	$0.003
E7: Cost of startup auxiliary power	$1.3K	$1.0K	$1.6K	$0.001	$0.001	$0.001
E8: Cost of startup fuel	$27.0K	$18.9K	$31.1K	$0.019	$0.013	$0.022
E9: Cost of startup (Operations – chemicals, water, additive, etc.)	$1.9K	$1.6K	$2.4K	$0.001	$0.001	$0.002
Total "incremental" cost of cycling (sum of E1 through E9)	$198.2K	$160.0K	$248.5K	$0.139	$0.112	$0.174

[1] Cost data refer to top down results for CY 2008, including fatigue-creep interaction effects and adjusted for signature data

[2] based on all analyzed warm starts and 2,851 net GWh during 7/07-6/08

[3] Over the last decade, maintenance and other activities have prevented significant heat rate increases

Note: Total best estimate = sum of individual ones; but this is not true of high and low totals

Table 2-4c -- Cost elements for COLD Shutdown-Start Cycles at Harrington Unit

Table 2-4c -- Cost elements for COLD Shutdown-Start Cycles at Harrington Unit 3
(based on CY 2008 cycles and in 2008 dollars)
Cold starts in 2000-2008 had averaged peak ramp rate of 140 MW per hour

	Baseline Data ($K/ cycle) [1]			Baseline Data ($/ 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	$30.0K	$7.5K	$44.5K	$0.011	$0.003	$0.016
E2: Cost of maintenance - includes maintenance and overhaul maintenance expenditures for boiler, turbine, generator, air quality control systems and balance of plant key components	$125.3K	$66.6K	$154.8K	$0.044	$0.023	$0.054
E3: Cost of capital maintenance - includes overhaul capital maintenance expenditures for boiler, turbine, generator, air quality control systems and balance of plant key components	$82.9K	$35.2K	$106.9K	$0.029	$0.012	$0.038
E4: Cost of forced outage and derate effects, including forced outage time, replacement energy, and capacity.	$62.0K	$40.9K	$72.6K	$0.022	$0.014	$0.025
E5: Cost of long-term heat rate change due to cycling wear and tear [3]	$0.0K	$0.0K	$0.0K	$0.000	$0.000	$0.000
E6: Cost of heat rate change due to low load and variable load operation (process related)	$3.7K	$2.8K	$4.9K	$0.001	$0.001	$0.002
E7: Cost of startup auxiliary power	$3.1K	$2.5K	$3.8K	$0.001	$0.001	$0.001
E8: Cost of startup fuel	$38.7K	$27.1K	$44.5K	$0.014	$0.010	$0.016
E9: Cost of startup (Operations – chemicals, water, additive, etc.)	$3.3K	$2.6K	$4.1K	$0.001	$0.001	$0.001
Total "incremental" cost of cycling (sum of E1 through E9)	$349.0K	$266.4K	$391.4K	$0.122	$0.093	$0.137

[1] Cost data refer to top down results for CY 2008, including fatigue-creep interaction effects and adjusted for signature data
[2] based on 2,851 net GWH during 7/07-6/08
[3] Over the last decade, maintenance and other activities have prevented significant heat rate increases

Note: Total best estimate = sum of individual ones; but this is not true of high and low totals

Table 2-4d – Cost Elements for Significant Load Follow Cycles at Harrington Unit 3

Table 2-4d -- Cost elements for Most Significant Load Follow Cycles (SLFs) at Harrington Unit 3
(based on CY 2008 cycles and in 2008 dollars)

	Baseline Data ($K/ cycle) [1]			Baseline Data ($/ 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	$0.26K	$0.07K	$0.82K	$0.0041	$0.0010	$0.0127
E2: Cost of maintenance - includes maintenance and overhaul maintenance expenditures for boiler, turbine, generator, air quality control systems and balance of plant key components	$1.10K	$0.31K	$2.24K	$0.0169	$0.0047	$0.0346
E3: Cost of capital maintenance - includes overhaul capital maintenance expenditures for boiler, turbine, generator, air quality control systems and balance of plant key components	$0.73K	$0.18K	$1.66K	$0.0112	$0.0028	$0.0256
E4: Cost of forced outage and derate effects, including forced outage time, replacement energy, and capacity.	$0.54K	$0.26K	$0.95K	$0.0084	$0.0040	$0.0147
E5: Cost of long-term heat rate change due to cycling wear and tear [3]	$0.00K	$0.00K	$0.00K	$0.0000	$0.0000	$0.0000
E6: Cost of heat rate change due to low load and variable load operation (process related)	$0.10K	$0.06K	$0.16K	$0.0016	$0.0009	$0.0025
E7: Cost of startup auxiliary power	$0.00K	$0.00K	$0.00K	$0.0000	$0.0000	$0.0000
E8: Cost of startup fuel	$0.00K	$0.00K	$0.00K	$0.0000	$0.0000	$0.0000
E9: Cost of startup (Operations – chemicals, water, additive, etc.)	$0.00K	$0.00K	$0.00K	$0.0000	$0.0000	$0.0000
Total "incremental" cost of cycling (sum of E1 through E9)	$2.73K	$1.71K	$4.36K	$0.0421	$0.0263	$0.0673

[1] Cost data refer to top down results for CY 2008, including fatigue-creep interaction effects and adjusted for signature data
[2] based on all analyzed significant LFs and 2,851 net GWh during 7/07-6/08
[3] Over the last decade, maintenance and other activities have prevented significant heat rate increases

Note: Total best estimate = sum of individual ones; but this is not true of high and low totals

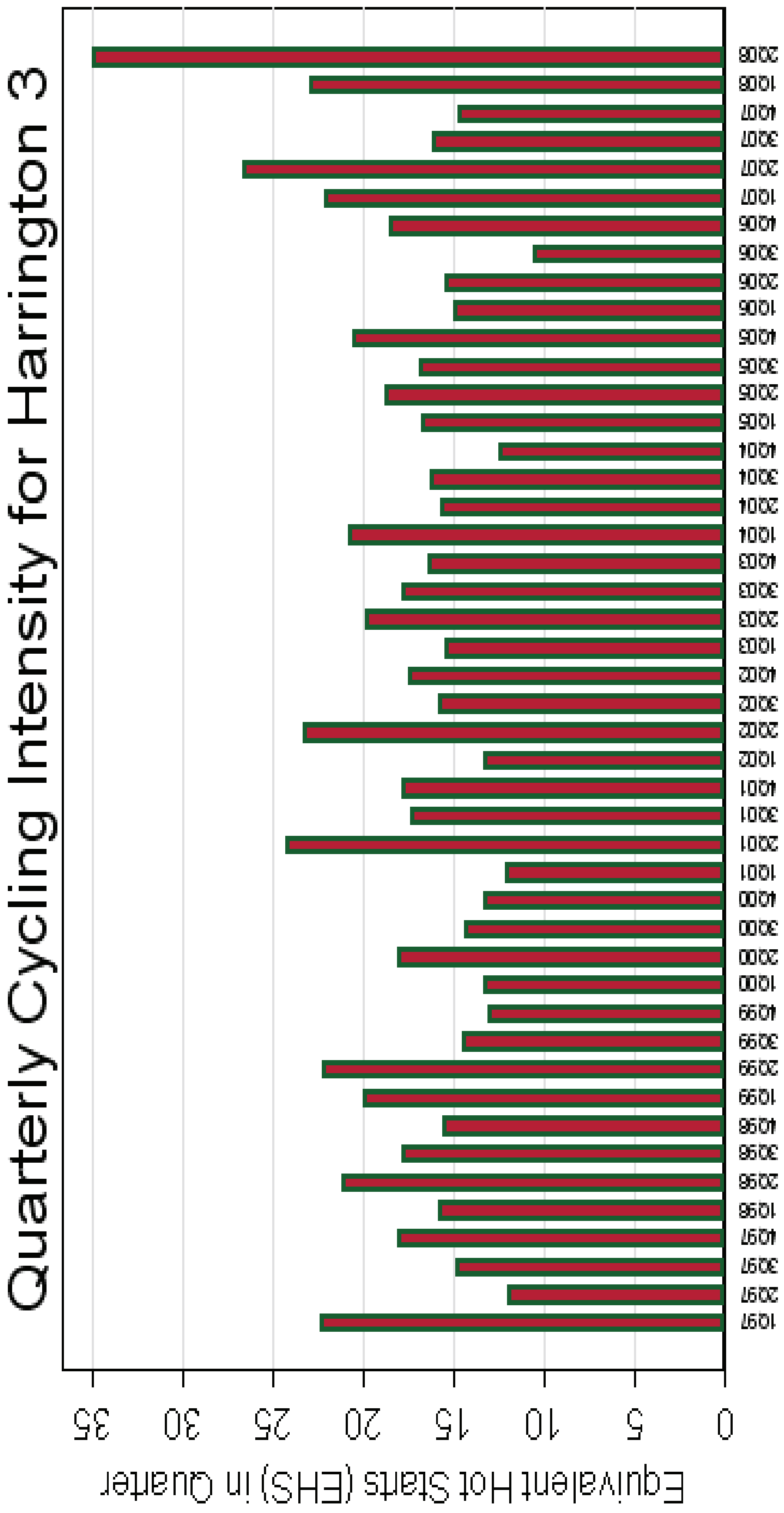


Figure 2-1 — Recent Quarterly Cycling Intensity for Harrington 3
Note increased level of cycling in 2008.

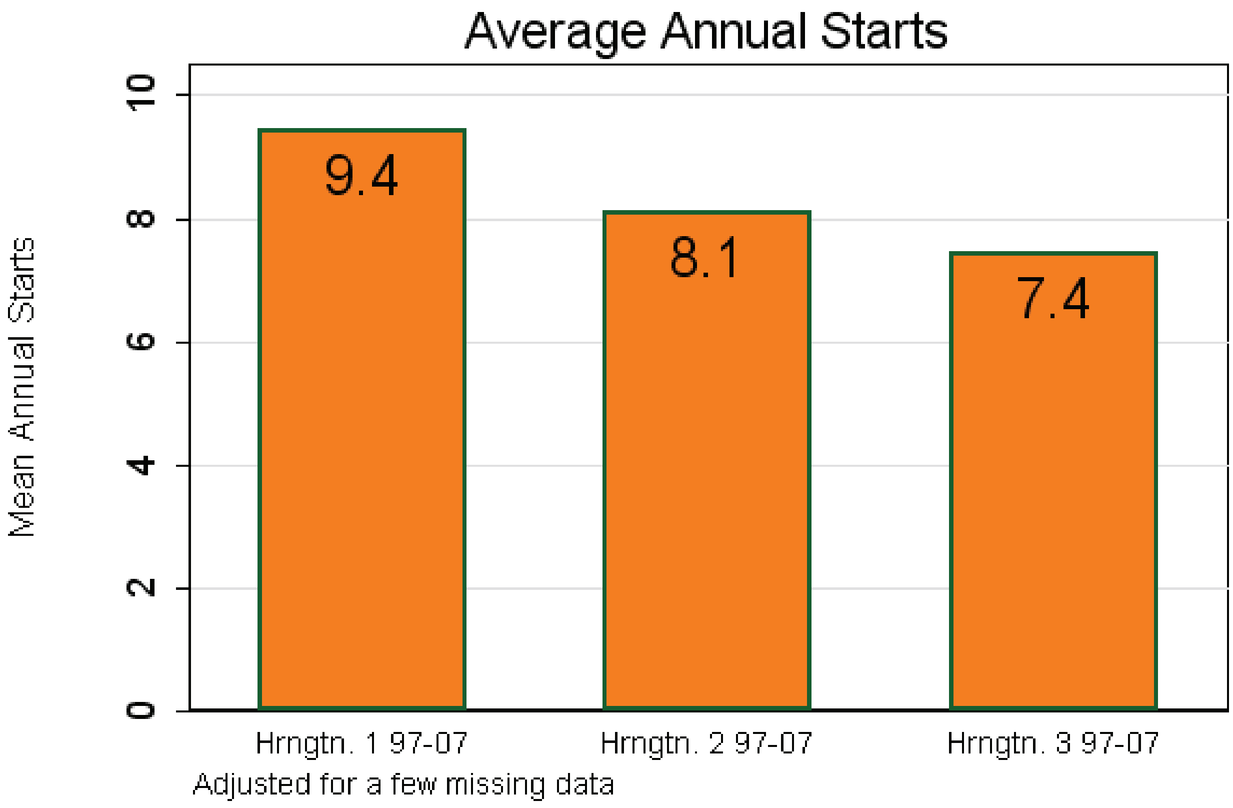


Figure 2‑2 — Harrington Plant Units 1, 2, and 3– Annual Number of Starts (1997-2007)

Note the few number of starts

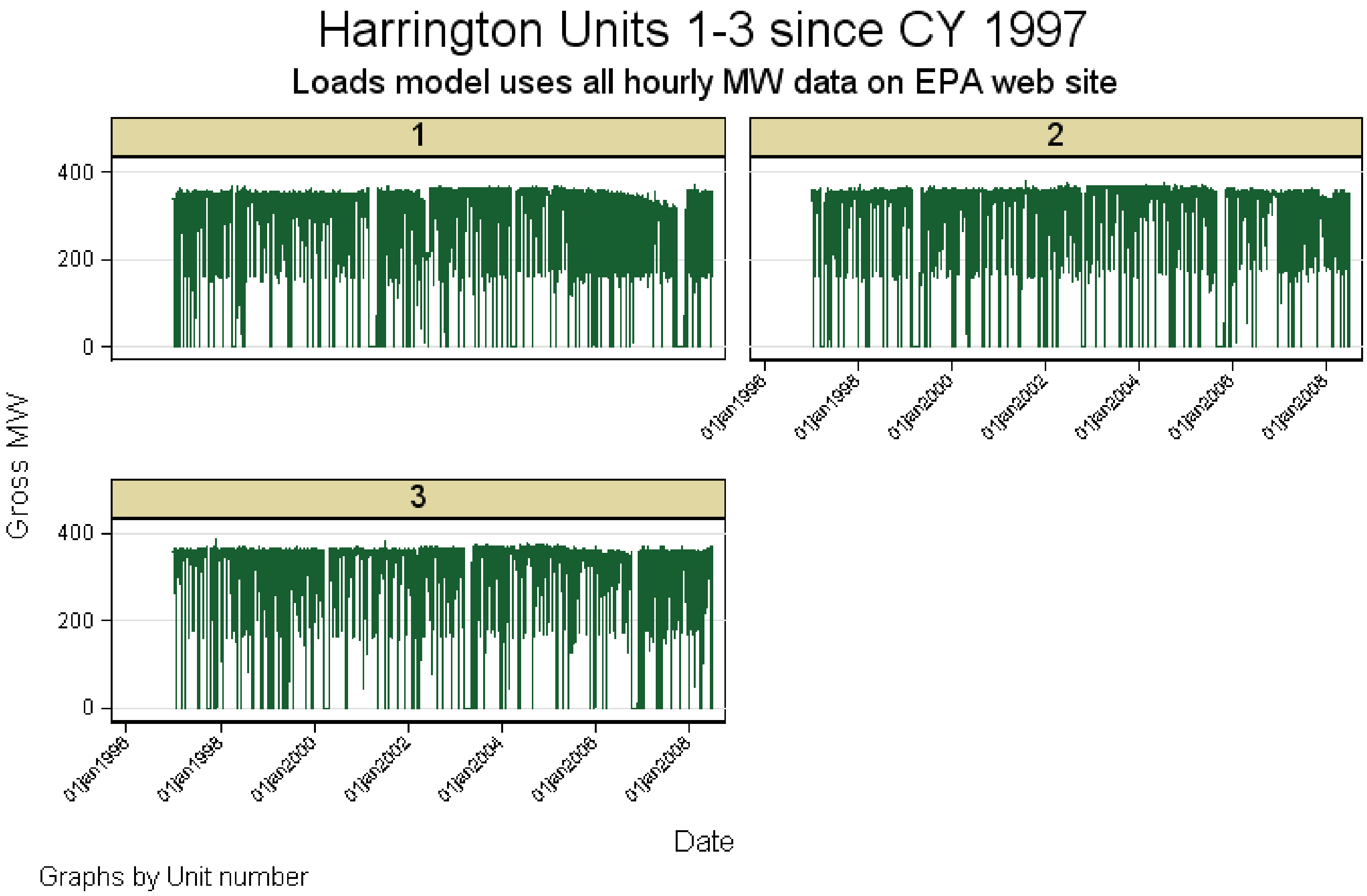


Figure 2‑3 — Harrington Units 1, 2 and 3 Hourly MW Data From USEPA

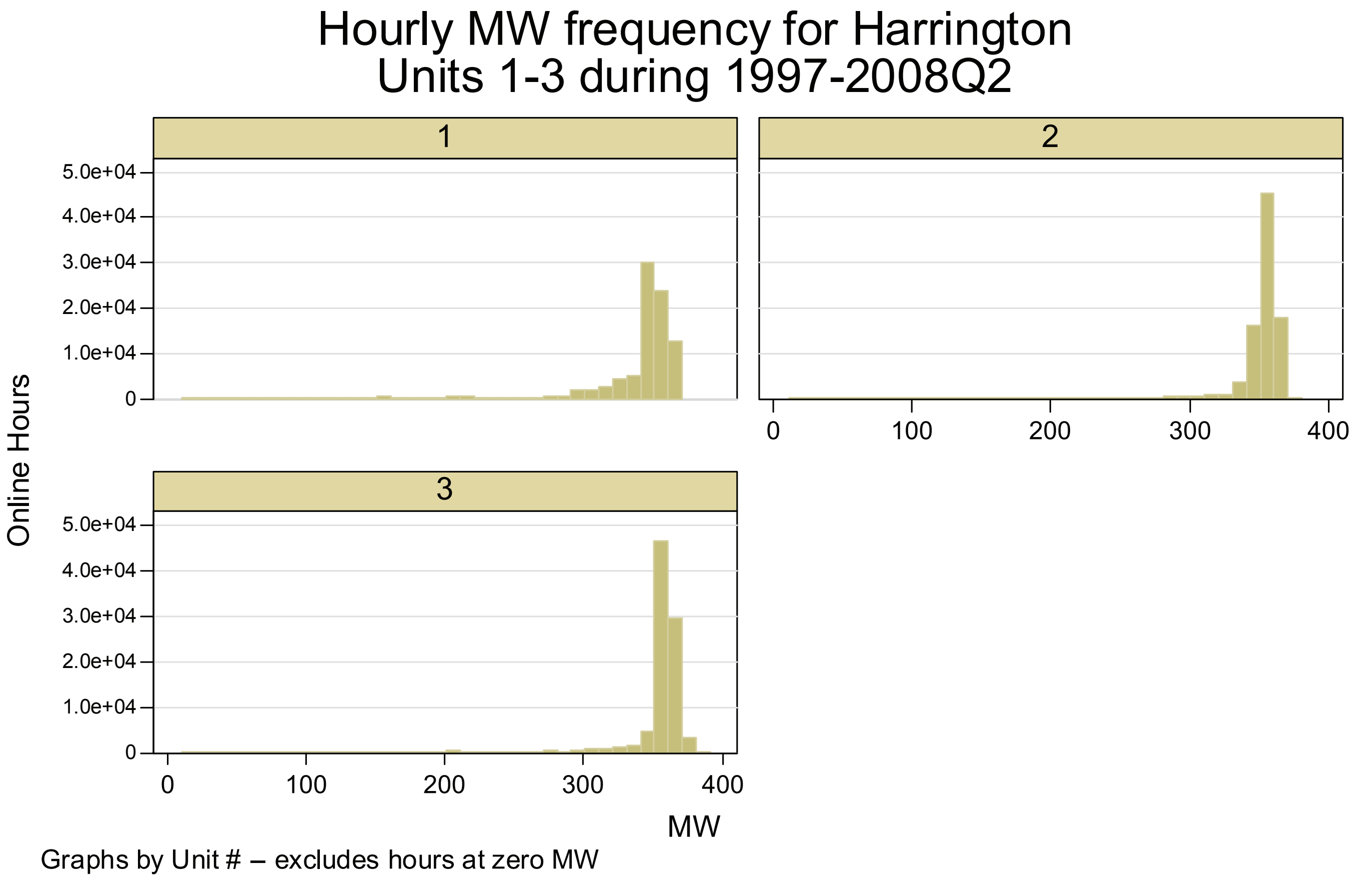
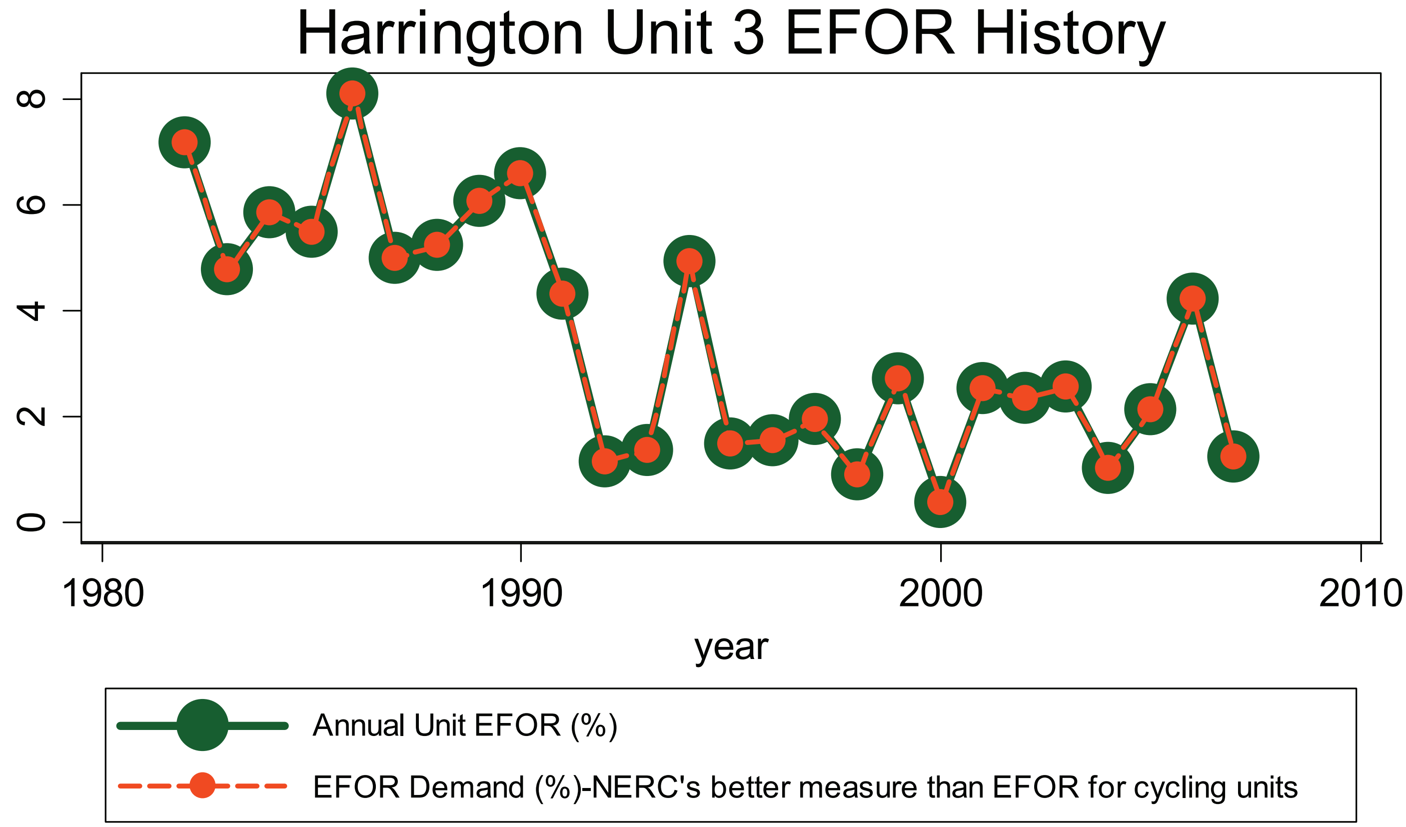


Figure 2-4— Hourly MW Histogram for all three Harrington units

These units are baseloaded with relatively few hours at minimum load



Based on NERC-GADS 1982-2007 annual summary
Note that EFOR demand is indistinguishable from EFOR for this baseloaded unit

Figure 2-5 — Harrington 3 Equivalent Forced Outage Rate History

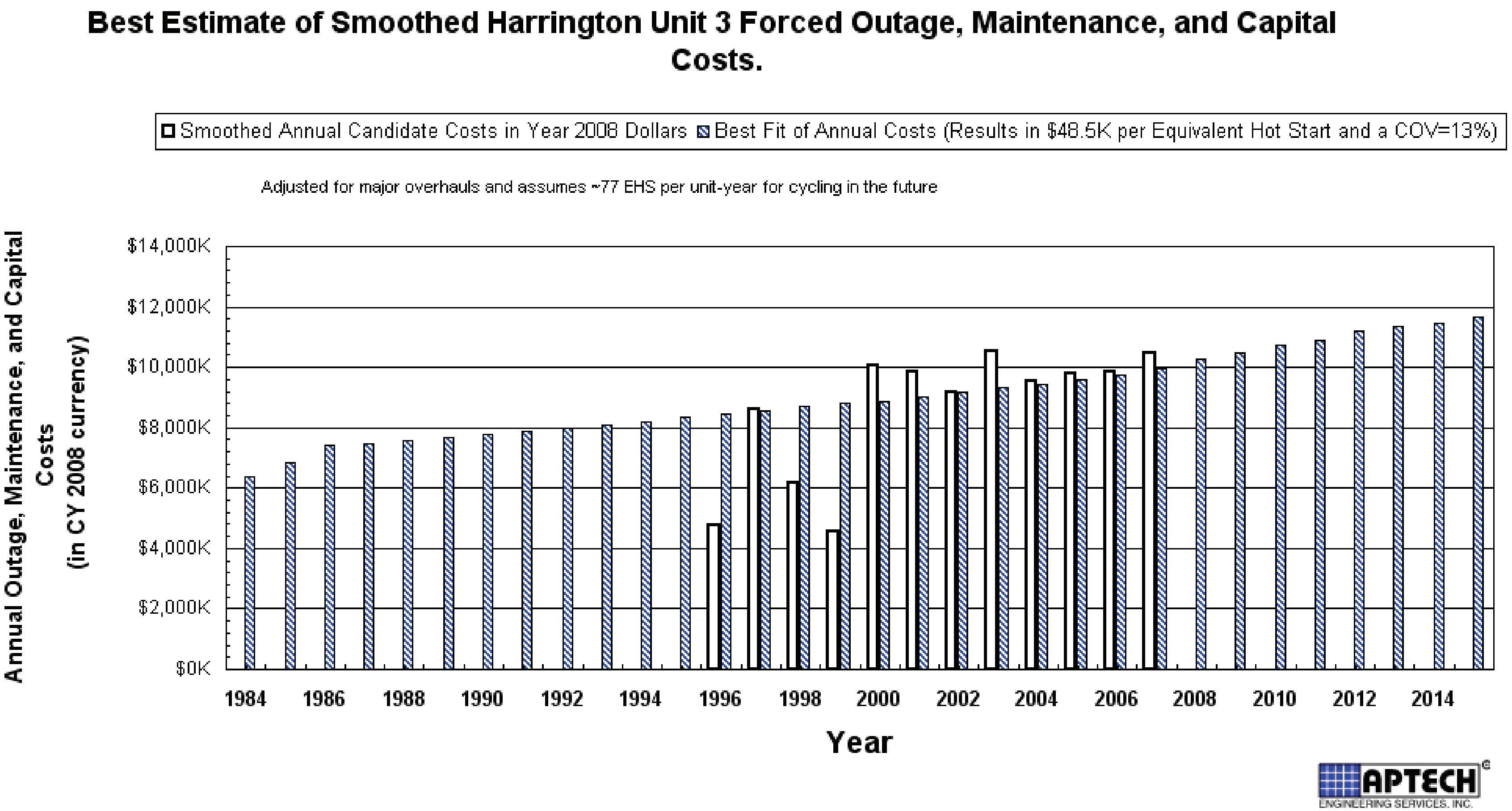


Figure 2-6 — Best Estimate of Smoothed Harrington 3 Forced Outage, Maintenance, Operation, and Capital Costs

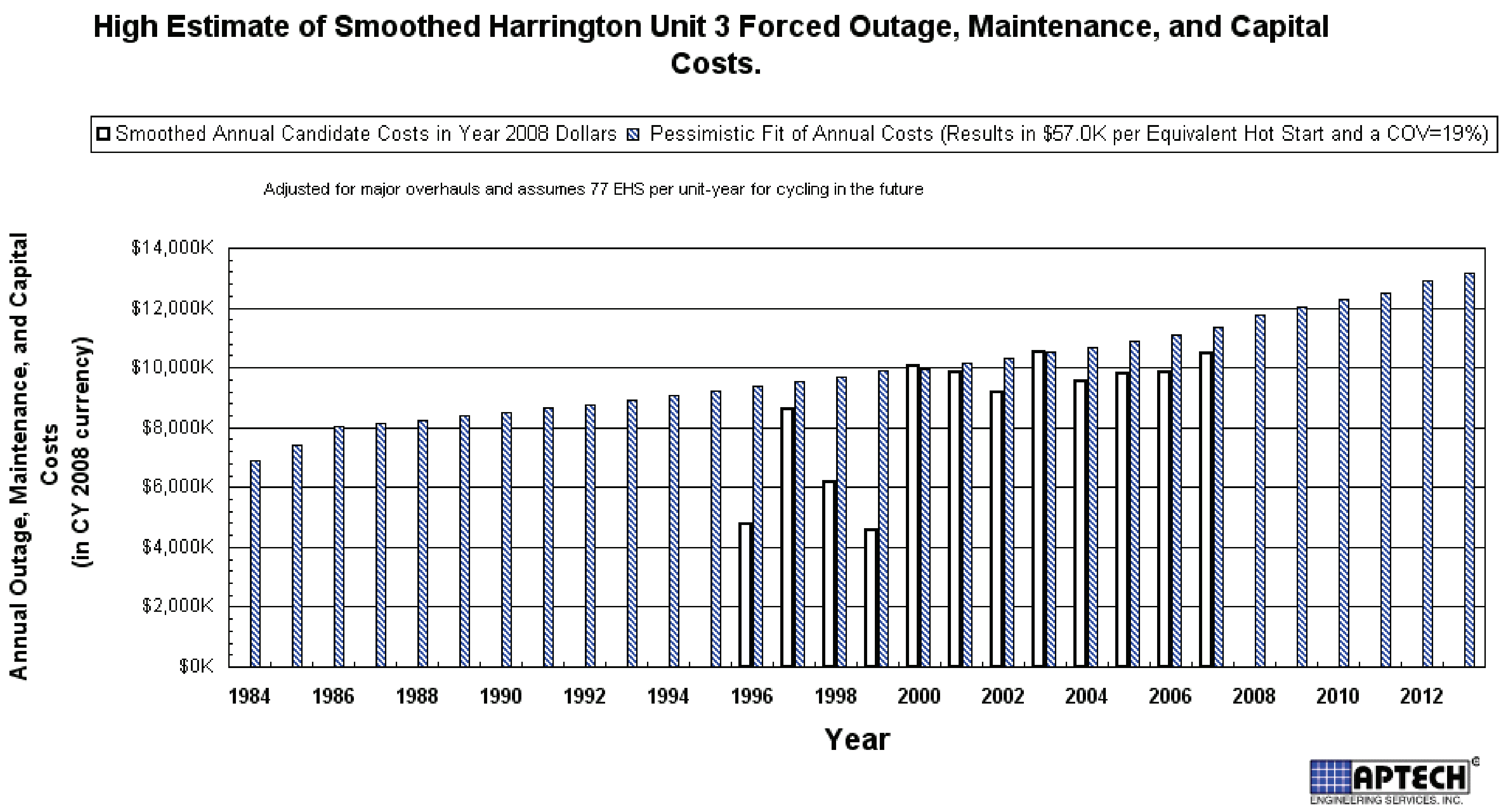


Figure 2-7 — High Estimate of Smoothed Harrington 3 Forced Outage, Maintenance, Operation and Capital Costs

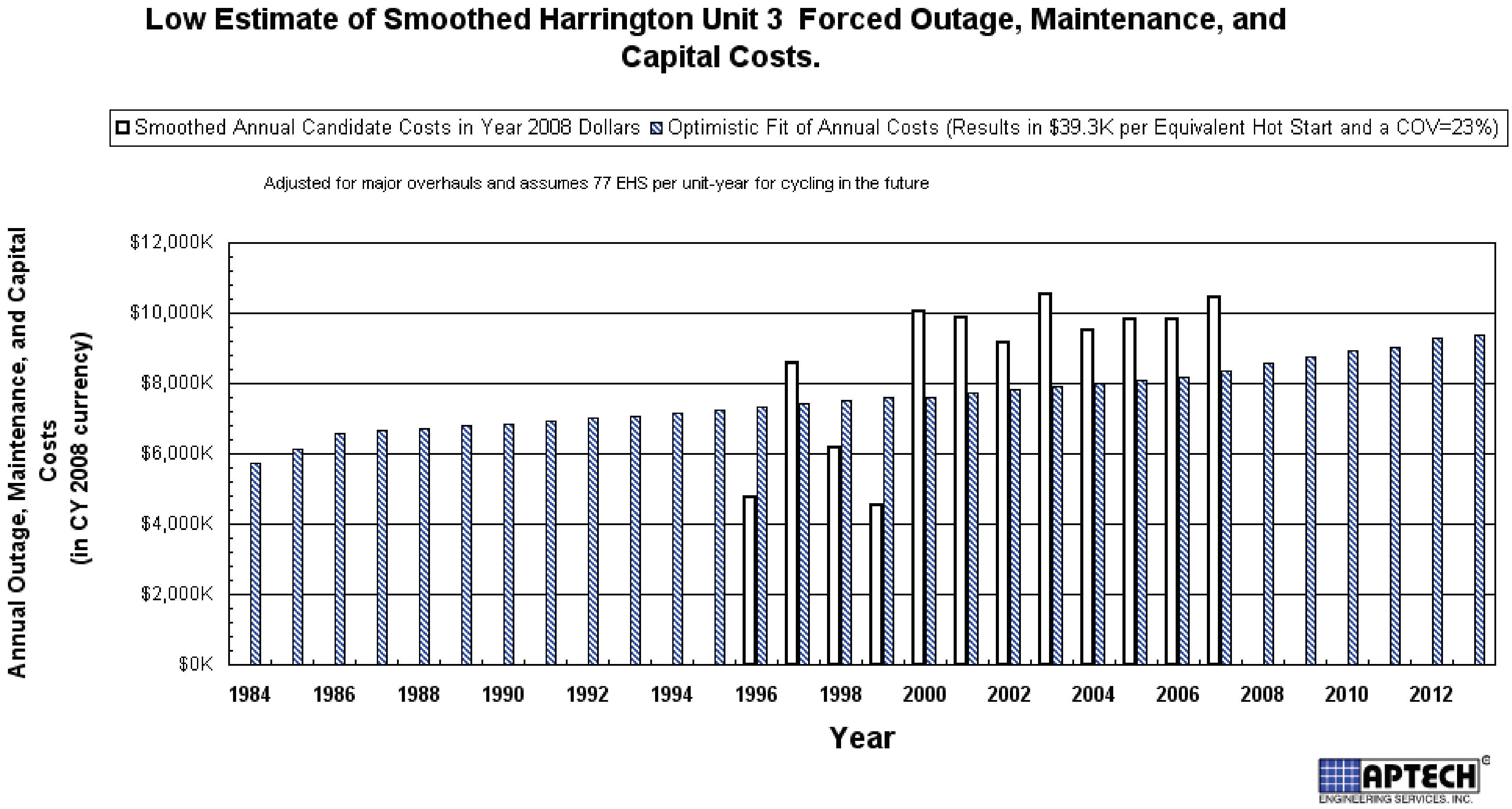


Figure 2-8 — Low Estimate of Smoothed Harrington 3 Forced Outage, Maintenance, Operation and Capital Costs

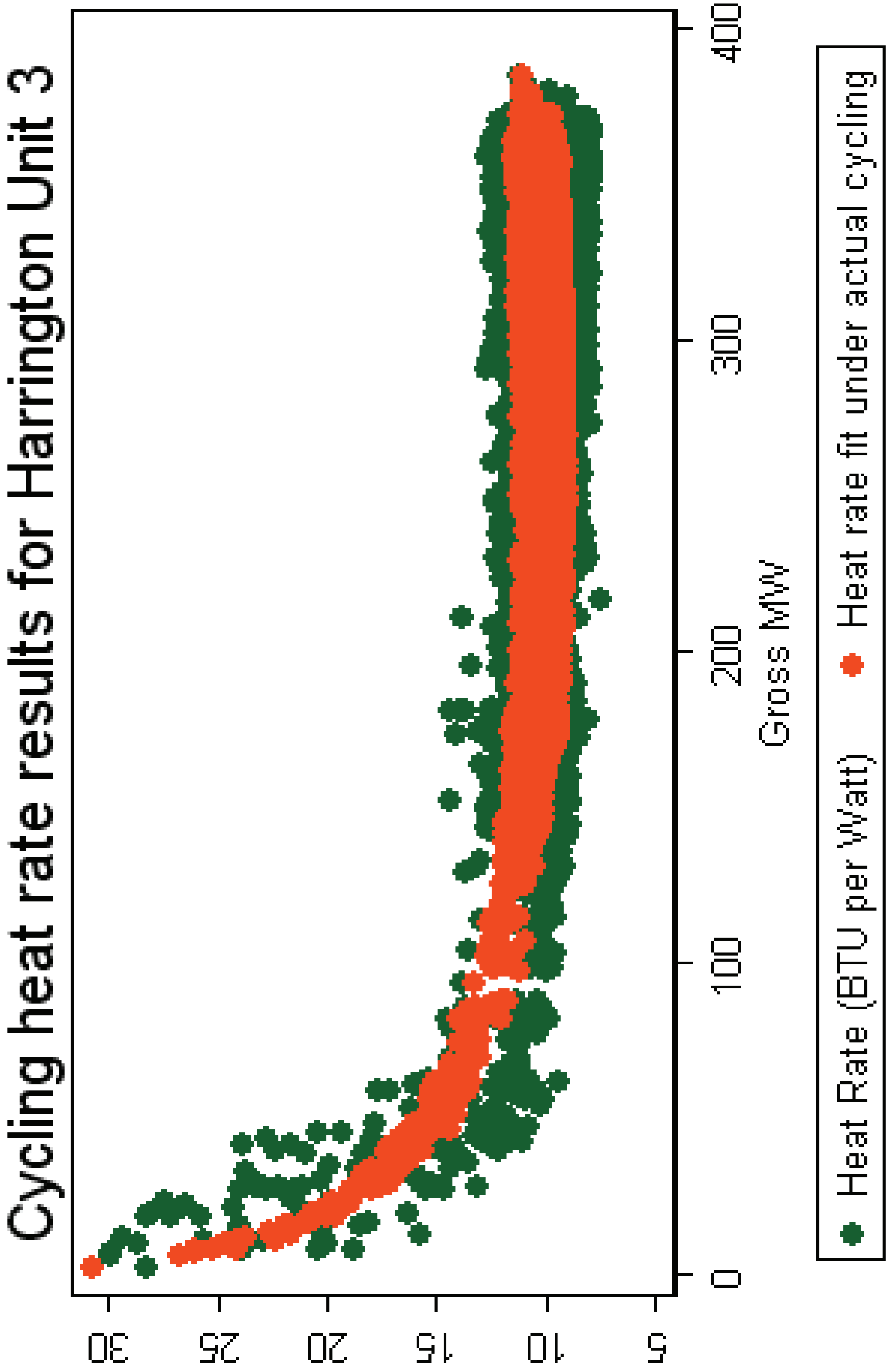


Figure 2-9 — Model for Over Eleven Years of Hourly Heat Rate Data for Harrington 3