Impacts of Increased Intermittent Generation on Baseloaded Coal Operations
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The National Rural Electric Cooperative Association

The National Rural Electric Cooperative Association (NRECA), founded in 1942, is the national service organization supporting more than 900 electric cooperatives and public power districts in 47 states. Electric cooperatives own and operate more than 42 percent of the distribution lines in the nation and provide power to 40 million people (12 percent of the population).

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- Control costs
- Increase service excellence
- Keep pace with emerging technologies

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## Executive Summary

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At least 32 states have adopted renewable electric requirements based on a percentage of total system energy production. These are essentially individualized versions of the much debated, but not enacted, federal renewable energy standard. Utility-scale wind is currently the most effective source for substantial renewable electric supply. As a result, both large developers and manufacturers are keenly interested in putting wind projects together for grid use.

Given the variability and intermittency of wind, the addition of high penetration of wind generation to the co-op grid will adversely impact the operation of baseloaded coal generation by making greatly increased demands on the operation and performance of baseloaded coal power plants.

Most fossil plants were designed and are operated as baseload units. When intermittent renewables are integrated into a G&T power system, however, fossil plants frequently are forced to cycle far beyond what was called for in their original design. Fossil plants could move from cycling perhaps just a few times a year to every week, and eventually daily, potentially requiring two-shift operation with additional annual warm and cold starts. For example, increasing amounts of wind resources cause fossil units to cycle from no load or minimum load at night, when wind tends to peak, to full load during the day, when wind typically declines. The consequences include increased wear and tear, lowered availability, and heightened costs.

The subsequent onset of cyclic damage and fatigue failures could be delayed by as much as 7 years for a new modern boiler, but could occur in as little as 9 to 24 months for an older one. This will result in more than doubling the current operations and maintenance costs for these facilities and an increased forced outage rate ranging from 5 to 10 percent up to 25 percent. In addition, the stress and strain induced by such outages inevitably cause additional outages. Over time, such forced outages actually result in greater damage to plants than does cycling. Replacement costs for these overworked plants also will increase significantly. O&M costs will most likely more than double, with significant cost increases in replacement energy costs, depending on the costs of the replacement unit (high-cost coal, natural gas combined cycle, or natural gas combustion turbines).

Despite the potential for substantial grid...
operational and dispatch impacts, wind turbines are currently the only renewable technology capable of making major penetration into today's generation mix, due to the following characteristics:

- A relatively low investment cost of $6,000 per average kW in comparison to large-scale solar at $19,000 per average kW (“$ per average kW” measures the amount of investment needed to produce an average of 1 kW of capacity throughout the year—it assumes a capital cost of $2,400 per kW at a 40% capacity factor)
- A significant number of interested large manufacturers and wind developers
- An attractively large implementation scale, since only 167 wind machines sized at 1.5 MW each would provide 100 average MW of wind generation

Given the expected increase in wind penetration and the potential consequences, there are ways to mitigate cyclic damage and the resultant increase in outages and costs. Cycling a formerly baseloaded coal boiler to respond to the variability of high amounts of wind penetration will require significant changes. It will require major modifications in dispatch and generation operations and extensive efforts by personnel in what previously were rather uneventful job functions.

This document takes a high-level look at the affect that 30% or more variable generation may have on co-op fossil generation assets. This document provides a co-op G&T perspective on the issue as described in two reports from two CEATI Thermal Generation Interest Group reports:

- **Damage to Power Plants Due to Cyclic Operations and Guidelines for Best Practices** which surveyed plant operators, manufacturers, and R&D organizations to assess the damage and best practices resulting increased cyclic operations industry-wide.
- **Damage to CCGTs due to Cyclic Operation** which collates and reviews available information and experience on the operation of combined cycle plant under cycling conditions. This report identifies the key engineering threats and operational constraints, assess the impact on engineering and operating costs, and provides guidelines on how to solve the problems associated with cyclic operation.

Both these documents as well as other related resources can be found on CRN’s website at [www.cooperative.com/about/NRECA/CRN/Results/Pages/DamagetopowerPlants.aspx](http://www.cooperative.com/about/NRECA/CRN/Results/Pages/DamagetopowerPlants.aspx).

To plan for next steps in mitigation, this report suggests reviewing applicable mandated renewables requirements, assessing the likelihood that disruptively high levels of wind generation must be accommodated, and estimating how long it might take to make needed changes in dispatch. After some internal rudimentary modeling to get a feel for the likely impact of wind generation and reviewing wind forecasting and baseload cycling issues with dispatch personnel, it recommends developing a plan and timetable for acquiring needed capabilities to cycle the plant.

Planning for updated control systems should begin at those baseloaded coal boilers most likely to be the first used for cycling operation. At the selected lead boiler, installation of a fully updated control and data system, including logic control subsystems, will help a utility to acquire experience for ultimately updating other units.

Finally, monitoring the status and projections for wind generation and modifying rollouts of dispatch improvements and baseload generation upgrades as appropriate will help to move a baseloaded coal-fired plant toward acceptable cycling service.

This report also presents new guidelines for cyclic operation and the replacement of components and materials. It analyzes operating problems; explains how components might fail and which components are the most susceptible to failure, particularly due to metal fatigue; offers best practices for preventive maintenance and repair, including control system upgrades; and addresses impacts on cost and plant reliability.

Experience indicates that, with proper attention to details, it is possible to cycle (or two-shift) coal-fired generating plants successfully. Moreover, response times can be improved with
better control systems and operational experience. In addition, this report discusses the potential of energy storage as a key mitigating factor. Although current storage technology by and large is not really a realistic fix at this time, storage in batteries at night, when wind is more available, and then using those batteries during the day, eventually could levelize the load and minimize wear and tear on baseloaded coal plants. Although not currently feasible in large sizes, storage eventually may pay for itself from other streams of value, such as providing frequency regulation, demand charge reduction or capacity credit, or T&D asset deferral (deferring a new transmission line or transformer), among others, and thus may be an economic option to mitigate the cost of cycling damage to fossil plants.
Introduction

The addition of intermittent generation to the grid will adversely impact the operation of baseloaded coal generation by increasing demands to cycle and two-shift baseloaded coal power plants. This report explains why this will occur and then analyzes the resulting significant impacts on baseloaded coal generation plants due to increased cycling and two-shift operations caused by the intermittency and uncertainty of wind generation. It also examines the resultant necessary facility, operational, and hardware upgrades; the steps needed to plan for such upgrades; and the potential of and options for energy storage as a key mitigation factor.

Wind Generation Impact on the Texas Grid

The Texas grid, known as ERCOT, was forced to declare an emergency condition during the evening of February 26, 2008 due to an abrupt loss of anticipated wind energy production. “Wind power levels often tend to drop off as the morning load increases and then pick up as the evening load declines. ERCOT operators had expected wind power production to dip to 700 MW but production fell to 300 MW. Operators implemented Step 2 of the emergency electric curtailment plan at 6:41 p.m. Most loads, according to the council, were restored and the grid’s operating reserves pushed back above 3,000 MW. Emergency conditions were cancelled at 9:40 p.m.”

ERCOT is essentially a ~30,000-MW grid in the off-peak season, with 8,000 MW of connected wind capacity. Since the average capacity factor of a wind generator is only 40%, the ERCOT grid was ‘scored’ as only a 9% wind renewables grid (8,000 MW of wind capacity at 40% average output = 3,200 MW of average wind energy). In addition, the West Texas portion of the grid has sustained negative seasonal system Lambdas (incremental grid power costs) for about 20% of its monthly hours. This means that wind generators actually were paying the grid to take their power for one-fifth of the time. The principal
driver of this cost appears to be the loss of Production Tax and Renewable Energy Credits if the wind generator shuts down. For this reason, the wind generators continued to generate and ERCOT paid the negative incremental power costs. Grid issues arising from the intermittency and uncertainty of wind generation thus are much more complicated for conventional coal baseloaded power generation than the casual observer might assume.³  

Intermittent Renewables Are Not Capacity—They Are Energy

At least 32 states have adopted renewable electric requirements based on a percentage of total system energy production. These are essentially individualized versions of the much debated, but not enacted, federal renewable energy standard. A state-by-state summary can be found at the U.S. Department of Energy’s (DOE) Energy Efficiency and Renewable Energy (EERE) web site.⁴ Pennsylvania has one of the lowest standards, targeting 8% renewables by 2020; Maine’s is the most ambitious, at 40% by 2017. The entire composite is 19% renewables within 10 years. A detailed summary of each state’s renewable electric rules can be seen at the Database of State Incentives for Renewables & Efficiency (DSIRE) web site.⁵ A key point, sometimes lost, is that the amount of electric renewables is mandated as a percentage of electricity sold on an energy basis.

As summarized in Table 1.1 at the end of this section, utility-scale wind is currently the only feasible source for substantial renewable electric supply. Wind requires comparatively few large units and both large developers and manufacturers are keenly interested in putting wind projects together for grid use.

Wind presents certain problems, however. Since it is essentially uncontrollable, wind is not a dispatch—or baseload generation-friendly supply. Wind power is highly variable and not always predictable. Moreover, its capacity factor (average output) is only around 40%, so to generate 100 MW of renewable energy on an annual basis, two and one-half times that amount of capacity would need to be installed (100 MW divided by 0.40 = 250 MW). The result is that at various times during the year, the amount of available wind power may range from 250 MW to none. As a consequence, when renewable wind reaches 30% of total system energy production, the impact on already existing conventional baseload generation becomes substantial.

Baseload Generation Is Significantly Impacted by 30% Wind

As shown in Figure 1.1 by the upper chart’s red line, normal co-op controlled generation averages 2,000 MW and ranges from 1,380 to 2,490 MW per hour. In contrast, as indicated by the dark gray shading, coal-fired boiler baseload generation is essentially a steady, hour-by-hour 1,400 MW year round. Gas turbines and combined cycle generators shown in lighter gray supply valuable and needed intermediate and peak load generation. (For simplicity, hydro generation is not shown as a separate supply subset.)

By comparison, the lower chart shows the impact of mandated renewables on the power supply mix. Since the customer load averages 2,000 MW, 30% renewable wind means that 600 average MW of wind energy must be added on an average annual basis. Given the typical wind capacity factor of 40% (average annual generation as a percentage of installed capacity), the required installed wind generation amount is 1,500 MW. This is determined by dividing the mandated 600 MW of average annual wind energy by the average annual 40% wind capacity factor. This means that to meet a 30% renewables mandate, the installed wind generation capacity will equal 75% of the grid’s average annual customer load—a huge increase.

The ‘30% Wind’ chart in Figure 1.1 was calculated from actual hourly wind speeds during randomly selected days from months throughout the year for a good Midwest wind location. However, wind generation is highly variable and intermittent. For this reason, two summer and three winter days are included on both charts to provide a more comprehensive picture of the impact of wind generation. The actual hourly
Wind generation covers a range of 0 to 1,370 MW. Because of the large variation in wind energy shown on this chart, the need for co-op controlled generation (indicated by the chart’s red line) varies significantly. While the amount of co-op controlled generation still averages 1,400 MW, it now has a more extreme range—from 65 MW to 2,470 MW. Intermediate and peaking generation also are much more variable. More important, baseload coal-fired boiler generation is impacted at various times throughout the year, especially in the spring and fall, making it more cyclical in daily operation. Note particularly the constraints on baseload coal generation during

* The above two charts show representative co-op system customer load and generation requirements on an hour-by-hour basis for eight typical days throughout the year. The top chart shows conventional present co-op generation. The customer load is met by a mix of natural gas turbines for peaking and intermediate loads; coal boilers are used for baseload generation. Hydro, if any, is not shown for simplicity. The bottom chart shows what happens when 30% wind generation is added to the supply mix.

From left to right across the charts, the first seven periods are weekdays—such as Monday through Friday—throughout the year. The last day on the right is a weekend day in the Spring or Fall. However, wind generation is highly variable on an hourly, daily, and even seasonal basis. To more fully illustrate the impact of various possible wind conditions, two different Summer wind days and three alternate Winter wind days are included in these overall daily generation profiles.

The various hour-by-hour load requirements for representative days throughout the year have been initially developed using June and December hourly load curves for a Midwestern G & T co-op. These were further refined using daily PJM load curves for a Midwestern non-urban utility. This enables the development of representative seasonal and weekend customer daily load profiles. The resulting analysis represents an average annual customer load of 2,000 MW.**

Wind generation impact is determined using randomly selected daily Midwestern wind data for six months. To illustrate the variability of the wind impact, two different Summer wind days and three Winter wind days are included. These show different applicable wind days within the seasons. The installed wind generation capacity is calculated to be 1,450 MW to provide the necessary average annual wind output of 600 MW. Thus, wind represents 30% of the annual customer load of 2,000 MW.

**Wind generation impact is determined using randomly selected daily Midwestern wind data for six months. To illustrate the variability of the wind impact, two different Summer wind days and three Winter wind days are included. These show different applicable wind days within the seasons. The installed wind generation capacity is calculated to be 1,450 MW to provide the necessary average annual wind output of 600 MW. Thus, wind represents 30% of the annual customer load of 2,000 MW.

FIGURE 1.1: Impact of 30% Wind on Conventional Co-op Baseload Generation. Source: Energy Signature Associates
Wind Variability and Mitigation

Figure 1.2 shows wind speed and the resulting power variations for a large Minnesota wind farm. The left chart shows typical wind and power variations over a 10-hour period; the right chart indicates power output as a function of various hourly wind speeds. The blue areas in the left-hand chart show substantial minute-by-minute and hour-by-hour variations in wind velocity. Wind speeds quickly change by 10 miles per hour within a few minutes. Also, marked changes can occur hourly and certainly between days. The resulting change in electrical power, shown by the red line, is even more variable.

A wind turbine blade is essentially an aerodynamic device. The end result is that its electric power output is a function of wind velocity cubed. For instance, if wind speed doubles from 7 to 14 miles per hour, actual wind generator power will increase by a factor of eight. As a result, actual power output variations are far more ‘peaky’ than wind speed graphs indicate.

There are two further complications: at wind speeds below approximately 5 mph, the turbine blades will not produce enough force to run their generator, and at speeds of approximately 25 mph, the blades begin to pitch or furl to prevent the generator from exceeding its maximum rated output. To use a hydroelectric power analogy, the wind is “spilled.” These elements define the shape of the red Manufacturer’s Generation Curve in the right-hand chart of Figure 1.2. This also explains why the average annual wind farm power output is about 40% of its installed capacity.
Spurred by the apparent randomness of wind velocity changes and the availability of moderate-cost, high-capacity data logging, a number of sophisticated statistical examinations of wind farm power outputs have been performed. One area of practical interest is the degree of benefit from multiple units at a site, or from diverse locations, in reducing wind power variability. The charts in Figure 1.3 highlight the impact of both of these mitigation concepts.

As shown in the chart on the left in Figure 1.3, adding eight or more generators to a site to create a wind farm materially improves the power output variability over one-hour periods. Interestingly, most of the mitigation from wind farms levels out by the time four to six units are installed at a given location; this is less pronounced for six- and twelve-hour variations. The impact of distance on mitigation is shown in the chart on the right in Figure 1.3. Wind farms must be at least 200 miles apart before much change occurs in power production variability. Even then, the improvement occurs principally in 30-minute and 1-hour increments. Surprisingly, even a separation of 1,000 miles does not appreciably mitigate one-day variations.

Dispatch Issues with 30% Wind Renewables

Two irrevocably intertwined issues emerge when a significant portion of wind generation is added to co-op dispatch and generation operations:

- First, how can dispatch of previously coal-boiler baseload operation be managed?
- Second, what will be the operational impact on these boilers, and can that impact be mitigated?

While the concerns about the increased cycling of baseloaded coal boilers will be addressed in the balance of this report, concerns also exist about related dispatch operations. These issues are discussed and assessed in more detail below.

Fortunately, the ERCOT wind analysis described earlier specifically analyzed load and wind dispatch concerns. These include the accuracy of day-by-day customer load projections and day-ahead wind generation estimates. Since ERCOT wind generation capabilities and annual customer load are well defined, the results can be directly rescaled to match the co-op case in Figure 1.1: that is, a co-op having a 2,000-MW average customer load with 1,500 MW of installed wind generation capacity (mandated 30% wind renewables).
Figure 1.4 shows forecasting accuracies for customer load on the horizontal scale and 30% wind on the vertical scale. The data show hourly forecast minus actual value. The 'shotgun' scatter generally is symmetrical, meaning that under- and overestimates are about equally likely for customer load and wind generation. However, a slight bias does exist downward and to the right. This means that customer load is more likely to be underpredicted, while wind generation is overestimated. The green I and III quadrants show the amount of time in which load and wind projection errors offset each other. The red II and IV quadrants show the number of times that projection misestimates exacerbate the issue, such as underestimating the customer load while overestimating the amount of wind energy available.

One of the most striking aspects of the graph plot is that wind forecast errors of plus 20% (300 MW more wind than predicted) to minus 30% (450 MW less wind than predicted) of installed capacity are possible even given the best day-ahead projections. Consequently, adding wind to the generation mix will lead to a more complex dispatch operation. Furthermore, serious outlier forecast errors leading to operational and grid problems are also much more likely.

**FIGURE 1.4: Wind Generation and Customer Load Forecasting Issues (30% Wind).** Based on GE ERCOT analysis and corrected for a co-op with 30% wind generation, having an average annual customer load of 2,000 MW.
With high variability, low capacity factor, mismatch with customer loads, and negligible dispatchability, wind is a renewable resource that carries substantial grid impacts. It does, however, have a number of implementation characteristics that make it essentially “the only real ballgame in town.” Table 1.1, Renewables Development and Issues, illustrates these characteristics.

Table 1.1 shows the relative amount of renewables presently on the grid, as well as the typical costs and levels of effort necessary to secure 100 MW of energy from various renewables. Wind capacity growth has two striking features: it represents more than 35,200 MW of installed renewables capacity and 86% of all renewables capacity added since the year 2000.

One reason is that, at $2,400 per kW and given a 40% capacity factor, wind has an investment cost of only $6,000 per average kW. This latter value is a good measure of “renewables capital efficiency” because “$ per average kW” measures the amount of investment needed to produce an average of 1 kW of renewables capacity throughout the year. In addition to the relatively low $6,000 per average kW for wind, many large manufacturers and developers are keenly interested in putting “turnkey” wind farms in place.

In comparison to wind, solar does not stack up well as a major grid source, except that it is less variable. Since the year 2000, 32,600 MW of wind have been added at the grid, but only 2,000 MW of solar PV and water heating. Moreover, PV and solar water heating cost significantly more, at $26,086 and $13,200 per average kW, respectively, neither providing a particularly attractive return for the residential consumers who might buy and install them.

While hydro has a large base of 77,700 MW...
### TABLE 1.1: Renewables Development and Issues (cont.). Source: Energy Signature Associates and NRECA (2011)

<table>
<thead>
<tr>
<th>Renewable</th>
<th>Cum Total</th>
<th>Since 2000</th>
<th>Cost to Add 1 kW of Renewables: Initial Installed Cost</th>
<th>Capacity Factor*</th>
<th>$/kW as Energy**</th>
<th>Effort Needed to Add 100 MW of Renewables Electric Energy Supply</th>
<th>Remarks</th>
</tr>
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<tr>
<td>Residential Solar Hot Water Heating17</td>
<td>—500</td>
<td>440</td>
<td>$6,500 per Installation = $1,450 per kW 11% CF $13,200 per kW Energy</td>
<td></td>
<td></td>
<td>Would need 205,000 electric water heater residences. Would require several hundred thousand individual homeowner decisions and investments. Based on 50 gal per day use. Much less expensive than solar PV, negligible permitting issues. More applicable in Southern U.S.</td>
<td></td>
</tr>
<tr>
<td>Hydro</td>
<td>77,700</td>
<td>720</td>
<td>$2,300 per kW Installed 70% CF $3,300 per kW Energy</td>
<td>Limited sites and virtually no interest by independent developers. Permitting is complex, contentious, costly, and time consuming.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Geothermal</td>
<td>3,090</td>
<td>290</td>
<td>$2,000 per kW Installed 90% CF $2,000 per kW Energy</td>
<td>Few active developers and sites.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Biomass, Including Co-firing</td>
<td>12,700</td>
<td>2,050</td>
<td>$300 per kW Biomass plus fuel costs of $5 to $8 per Mil Btu of biomass. Assumes a combination of crop residue and switchgrass.</td>
<td>Depending on the location and state, between 3,000 to 12,000 square miles or more of geographical area would be required to provide 100 MW of biomass co-firing fuel. Given a technological limit of 10% biomass co-firing, 900 MW of coal firing would be required for every 100 MW of co-firing. Would likely require self-development by the fuel user. However, the EPA has just announced that biomass will be treated the same as fossil fuels when new greenhouse gas permitting regulations come into play in 2011. This will essentially eliminate this biomass option for renewables generation.</td>
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Installed since 2000: 37,670 MW

* “Capacity Factor” is the average annual electric production as a percentage of the Installed Capacity. In effect, it is the expected Average Annual Output in kWh or MWh, divided by the Installed Capacity in kW or MW × 8,760 hours per year. Thus, Capacity Factor is a measure of the “efficiency” with which the installed generation can be used throughout the year. This is particularly important because Electricity Renewable Requirements are almost always based on a percentage of the annual energy sold (kWh or MWh) and not merely as a percentage of installed generating capacity (kWh or MW)! For example, a 30% renewables requirement for a co-op having a 2,000-MW average annual customer load and generation capacity means that 30% of the electricity sold (30% × 2,000 MW × 8,760 hrs/yr = 5,256 million kWh per year) must come from renewables generation. To reach this level would actually require 1,500 MW of installed wind generation or 75% of the customer load (5,256 million kWh per year divided by 8,760 hours per year and 40% capacity factor = 1,500 MW of wind generators).

** “Dollars per kW Energy” is the installation expenditure that will yield 1 kW of average annual energy. It is calculated by dividing “Dollar per kW installed” by the “Capacity Factor” of the generator. Thus, it is a good measure of the cost efficiency of the kW capacity investment dollars.
and a relatively attractive cost, only 720 MW have been added since 2000. Limiting factors include site availability and a complex, contentious, and lengthy permitting process. During the same period, geothermal added only 290 MW, making it even less of a contender as a renewables source.

Biomass, including co-firing in coal boilers, has added 2,050 MW since 2000. Crop residue and switchgrass co-firing of coal baseload boilers would be an ideal renewables addition to grid and co-op operation. As shown in Table 1.1, however, biomass implementation is a formidable undertaking. Depending on the location, somewhere between 3,000 and 12,000 square miles of land would be required just to supply crop residue and switchgrass for 100 MW of renewables, and the recent cost for processing and delivering “waste” biomass, or even dedicated biomass, is more than $100/ton or more than $7/MBtu, resulting in fuel costs alone reaching almost 10 cents/kWh.

Moreover, there are no large-scale developers or aggregators of biomass fuels for coal co-firing. This would leave the entire endeavor—from crop development and acquisition through transportation and storage—for development by the co-op boiler operator. In addition, a crucial new impediment has arisen. The recently proposed EPA rules state that biomass will be treated like fossil fuels when new greenhouse gas permitting regulations come into play in 2011. This essentially will eliminate the biomass option for renewables generation.

Although wind has high variability, is seasonal (blows in the spring and fall when capacity is not needed), blows during off-peak periods, and has a poor capacity factor relative to a baseloaded coal boiler, its implementation is far easier than any other renewable because of the following:

- A relatively low investment cost of $6,000 per average kW in comparison to solar at $19,000 per average kW
- A significant number of interested large manufacturers and wind developers
- An attractively large implementation scale, since only 167 wind machines sized at 1.5 MW each would be needed to provide 100 average MW of wind renewables energy

Currently, these factors are why wind is almost certainly the only renewables ballgame in town for major amounts of mandated renewables for co-op grid supply. This also is why the impact of wind on traditional coal baseload boilers is an emerging critical issue.
In This Section:

- Changes and Concerns
- Aging and Cycling of Baseload Coal Plants
- Impact of Cycling on Baseload Coal Plant Reliability
- Cost of 25% EFORs due to Cycling Coal Boilers
- Cost of a Cycling Coal Boiler: Hot-Warm-Cold Startups
- Cost of Cycling Summary
- Facility Cycling Issues and their Mitigation
- Next Steps

Changes and Concerns

The charts in Figure 2.1 are simplified from those in Figure 1.1 to better illustrate co-op-controlled generation demands before and after the addition of 30% wind generation. The upper chart shows a relatively predictable baseload coal generation supplemented smoothly by natural gas combined cycle and combustion turbines to meet intermediate and peak customer loads.

By contrast, the bottom chart in Figure 2.1 shows the resulting co-op-controlled dispatch requirements after 30% non-dispatchable wind energy is subtracted from daily customer loads. The relatively stable generation planning and operation environment has disappeared. To fully appreciate the impact, imagine that you are a dispatcher or power plant manager and cover part of this chart with your hand. Even with the best day-ahead wind forecasts covering multiple wind farms, you can see how difficult it is to predict what you will (or should) generate from coal units in the next: 1, 2, 4, 8, 24, and 48 hours.

A number of striking issues and challenges immediately become apparent:

- The availability of control, dispatch, or curtailment requirements that can, or should, exist in wind purchase to help mitigate these wind impacts;
- Much more complex and stressful dispatch operations, even given the best of day-ahead wind forecasts;
- Less predictable and erratic natural gas combined cycle and gas turbine operations (intermediate and peaking loads), since part of their function likely will expand to assist the dispatch timing (startup and shutdown) of coal baseload steam plants;
- Increased stress on coal-fired baseload power plant operation and maintenance personnel due to faster required responses; much more variation in levels of operation and resultant higher maintenance; and a broader range of fast shutdowns and more and varied startups,
Aging and Cycling of Baseload Coal Plants

Figure 2.2 shows key metallurgical factors associated with power plant deterioration and overall life. These are “Creep,” which increases from left to right across the bottom, and “Fatigue,” which increases up the vertical axis. The black boundary line on the chart marks the end of the boiler’s life.

The blue line in Figure 2.2 represents conventional baseload operation. It is relatively long because there are few temperature cycling starts to cause fatigue. According to data from the North American Electric Reliability Corporation (NERC), an average utility baseloaded coal boiler runs around 500 hours per start; large 1,000-MW units average 850 hours after startup. As cycling, or “two-shifting,” is initiated, the related orange lines bend upward and hit the solid black line that denotes the boiler tubes’ end of life due to additional fatigue damage. The result is a shortened boiler life. The red upward service life line denotes continuous cycling since boiler commissioning, which is controlled principally by fatigue limits.

Creep occurs where metals are used at relatively high temperatures while concurrently exposed to unvarying mechanical stresses that are less than the yield strength of the material, but nevertheless cause plastic deformation or creep to occur—particularly after a long period of time. Specifically, creep occurs above temperatures that are more than 40% of the material’s melting point (in ‘absolute degrees’—this means

including increased hot, warm, and cold starts; and

- Increased mechanical and metallurgical stresses incurred by coal-fired baseload plants due to much more rapid and varying modes of operation, increased numbers of shutdowns, and varying types of startups.
above 850°F for steel and 1,200°F for nickel alloys). Thus, creep typically is associated with baseloaded boilers that run for long periods of time with infrequent starts.

Fatigue occurs in materials subjected to fluctuating stresses. Under such circumstances, failure can occur at stress levels considerably below the tensile or yield strength of the metal. ‘Fatigue’ is the descriptor because this type of failure normally occurs after a lengthy period of repeated stress cycling. Although the onset of fatigue failure is slow, catastrophic fatigue failures occur very suddenly and without warning. This is because metal suffering from fatigue failure becomes brittle-like, even in normally ductile metals. Little, if any, deformation occurs prior to the failure.

Fatigue failure occurs through the occurrence and propagation of cracks, with the fracture surface usually perpendicular to the direction of an applied stress. A major element in fatigue is the influence of design. While it is possible to assess the inherent fatigue resistance of a material, the effects of stress-concentrators, such as surface irregularities and changes in cross-section, as well as the crucial area of jointing, can cause major problems.

Fatigue failure is exacerbated by the application of cyclical stresses. The appearance of a fatigue fracture surface is distinctive and consists of two parts: a smooth part, often showing “mussel shell” markings that indicate the progress of the fatigue cracks up to the moment of final rupture, and a part showing the final fast fracture zone.

Uneven heating also can lead to thermal fatigue, particularly where oxidation and corrosion further degrade creep and fatigue resistance. The most common components damaged by thermal fatigue in boilers are boiler and turbine valves, steam headers, de-aerators, boiler drums, and the turbine steam chest.

**Impact of Cycling on Baseload Coal Plant Reliability**

A boiler’s Equivalent Forced Outage Rate (EFOR) is the percentage of time that the boiler cannot operate while connected to the grid. In effect, this indicates a serious problem somewhere in the plant that either needs repair or is being fixed. Also included in the EFOR calculation is a proportional adjustment for the amount of time, if any, that the plant runs at less output than normally expected, although generally this is a minor component. Thus, EFOR is essentially a measure of the boiler’s down time when it should have been running at full output.

The solid blue line in Figure 2.3 shows the average number of cycles that 10 plants in the United Kingdom experienced each year during three decades of operation. In comparison, the purple squares show the average annual EFOR for the fleet of 10 plants during those years. The
to become apparent in failures resulting in forced outages. Aged boilers of questionable metallurgical health also will accelerate the effects of cycling.

The utility coal-boiler cycling effects chart in Figure 2.4 illustrates the impact of various operating patterns over the boiler’s lifetime. The solid black line at the bottom shows that the EFOR for a continuously baseloaded boiler rises gradually to around 10% by the end of its life.

However, in this illustration, when a previously baseloaded 18-year old boiler begins cycling operation, the EFOR rate bends abruptly upward to reach a 28% forced outage rate by the end of the boiler’s life. This deterioration is portrayed by the broken yellow line. It assumes that no upgrades are made to the boiler either at the initiation of, or during, cycling duty. Alternatively, if cycling upgrade investments are made to the boiler at the initiation of cycling, the resulting broken light blue line avoids about two-thirds of the forced outage increase, although ultimately it still reaches a 17% EFOR.

An alternative option using less expensive periodic upgrades is denoted by the dark blue stepped-down lines. These illustrate that periodic capital expenditures after cycling damage has occurred can still drive the forced outage rate downward to more acceptable levels.

Interestingly, most coal-fired generation facilities owned by co-ops fall into this aging baseloaded category. Unpublished work based on 2006 Energy Information Administration (EIA) reports for the entire 39,900-MW rural co-op generating fleet details more than 20,000 MW of coal-fired workhorse boilers. These co-op coal units average 392 MW in size, with a size-weighted average age of 29.0 years in 2006.
The impact of highly variable generation will cause aged baseloaded coal boilers to be pressed into cycling duty. Absent cycling upgrades, the EFOR level of these units is expected to increase substantially. What is the likely economic impact of increased coal boiler forced outages due to wind cycling? Determining the answer depends on assessing two components: (1) What are the “normal” scheduled and EFOR costs during baseloaded operation? and (2) How do “normal” maintenance costs change with increased cycling EFORs?

Unfortunately, most utility reports lump maintenance and operating costs together, as well as adding in startup fuel, chemicals, and related costs. However, at least some reasonably authoritative coal-fired studies have resulted in usefully detailed capital and operating cost analyses based on recommended utility boiler cost estimating guidelines from the Electric Power Research Institute (EPRI). Recent examples are the National Renewable Energy Laboratory (NREL) studies on coal-fired generation options. NREL estimated direct annual maintenance costs of $5.6 million for labor and $8.4 million for materials for a 583-MW pulverized coal (PC) subcritical boiler with limestone flue gas desulfurization (FGD). Since the related scheduled and unscheduled maintenance periods also are known, the effective hourly repair expense can be estimated. These calculated hourly costs total the same NREL-EPRI projected cost of $24,013 per MW per year, based on a projected 10% scheduled outage rate and a 5% EFOR maintenance.

This scheduled outage period is set aside each year for normal annual repairs, refurbishments, and even possible upgrades. Typically, this period represents 8 to 10% of the hours in the year. A forced outage, specifically an EFOR, is different. This represents the unexpected time that the unit is down (including an adjustment, if derated) during expected dispatch. Typical EFOR experience for a coal baseloaded unit is between 5 to 7%. This means that a baseloaded plant would be expected to be available after its scheduled outage for 7,884 (8760 – 876) hours a year. Thus, a 5% forced outage at such a facility would mean 394 hours (5% of 7,884) per year of additional unscheduled repairs.

However, if the unit is cycling because of varying wind generation, the expected dispatch might only be 5,000 hours a year. As a result, a 5,000-hour dispatch cycling boiler with an EFOR of 25% would need 1,250 (25% of 5,000) annual hours of unscheduled repairs. Thus, calculating the amount of EFOR hours to develop the related maintenance costs also depends on knowing the targeted dispatch hours against which EFOR is measured. For example, a 25% EFOR on a cycling 5,000-dispatch boiler compared to 5% rate on a baseloaded boiler does not mean a 5:1 ratio of unscheduled repair hour costs, but rather, a 3:1 ratio (1,250 divided by 394).

The results show a significant cost increase when a baseloaded coal boiler is pressed into cycling service with either no or minimal upgrades. The resulting maintenance and replacement fuel cost shown in Table 2.1 would nearly double, from $15.8 million per year for a baseloaded coal boiler at 5% EFOR to $31.2 million for a cycling coal boiler with a 25% EFOR. Embedded in these totals is the fact that the maintenance cost portion increased 22% to $11.1 million a year. Even so, this increase is based on what may be optimistic assumptions: the cost of unscheduled maintenance hours is assumed to be only 50% of scheduled maintenance, due to logistical limitations; and one-quarter of the cycling EFOR’s unscheduled maintenance expenditures are assumed concurrently to reduce the next scheduled maintenance efforts by a similar offset. If instead, both scheduled and unscheduled maintenance efforts expend the same cost per hour of maintenance, and if there is no offset against next year’s scheduled maintenance, then the 25% EFOR cycling maintenance would increase annual maintenance costs to more than $17 million—an 80% increase over the baseloaded maintenance cost of $9.6 million.

Even more substantial—and certain—is the cycling cost increase due to EFOR replacement power. During cycling EFOR outages, the low-priced electricity expected from $1.50 per million Btu coal in a 9,200 heat-rate boiler will need to be generated elsewhere. The assumption is that combined cycle and combustion turbines will be pressed into service. These would use $6.00 per million Btu natural gas at an average heat rate of 8,817 Btu. As explained in Table 2.1, the resulting cost for this total of 1,250 hours
Co-op Baseloaded 400-MW Coal Boiler with 5% EFOR (Base Case) | Co-op Cycling 400-MW Coal Boiler at 5,000 Dispatch Hours with 25% EFOR  
---|---  
**Annual Maintenance Cost**  
| |  
| **Scheduled Maintenance** | $20,287 /MW-year | **Scheduled Maintenance** | $17,333 /MW-year  
| **Unscheduled Maintenance** | +$3,726 /MW-year | **Unscheduled Maintenance** | +$11,816 /MW-year  
| **Total** | $24,013 /MW-year | **Total** | $29,149 /MW-year  

The resulting maintenance cost for a 400-MW co-op coal-fired baseloaded boiler at 5% EFOR would be $9,605,000 per year.  

The resulting maintenance cost for a 400-MW co-op coal-fired cycling boiler with 5,000 hours of annual dispatch at a resulting 25% EFOR would be $11,660,000 per year.  

Excludes operating labor, chemicals, startup fuel, and all other non-maintenance items. Initial costs are from a detailed cost projection for a baseloaded 583-MW (gross) subcritical pulverized coal facility with wet limestone flue gas desulfurization. Scheduled maintenance per EPRI guidelines is 10% plus an EFOR of 5%. Unscheduled maintenance repair hours due to EFOR incidents are assumed to be expended at 50% of the hourly cost of scheduled maintenance activities. This is because of cool-down delays and normal repair pre-staging constraints of EFORs. The calculations are then prorated to a 400-MW co-op coal-fired baseloaded boiler.  

Source: NREL’s Cost and Performance Baseline for Fossil Energy Plants, which assumes that the maintenance labor for a 583-MW boiler is $5,600,000 and $8,400,000 for materials. Thus, total annual maintenance is approximately $14,000,000 per year, or $24,013/MW year.

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**Table 2.1: Comparative Annual Maintenance and Replacement Fuel Cost for a Co-op 400-MW Baseloaded Coal Boiler with 5% EFOR versus a Cycling Coal Boiler with a 25% EFOR.** Source: EPRI Guidelines via NREL’s Cost and Performance Baseline for Fossil Energy Plants

<table>
<thead>
<tr>
<th></th>
<th>Baseloaded with a 5% EFOR</th>
<th>Cycling with a 25% EFOR</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Annual Fuel Replacement Cost</strong></td>
<td>$15,767,000</td>
<td>$31,210,000</td>
</tr>
<tr>
<td><strong>Total Annual Maintenance and Fuel Replacement Cost for a 400-MW Coal Unit</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Baseloaded with a 5% EFOR</td>
<td>$15,767,000</td>
<td>Cycling with a 25% EFOR</td>
</tr>
</tbody>
</table>
A major component of the costs of increased EFORs described above is the cost of the related Hot-Warm-Cold startups. In effect, the increased maintenance cost due to larger EFORs is one way of measuring cycling startup damage. Typically, as shown at the top of Table 2.3, startup types are defined by the number of hours since the boiler last operated: Hot <12 hours, Warm = 12 to 72 hours, and Cold >72 hours. Another definition used is Warm <24 hours. However, in actual practice, after certain cycling upgrades, these break points are better defined from selected internal boiler temperatures.

As could be expected, estimates of startup costs vary markedly, depending on equipment, size, included items, analysis detail, and a whole host of other factors. Examples of the resulting wide variations are shown in Table 2.2.

Additionally, some wear-and-tear rules-of-thumb have emerged, albeit of somewhat uncertain accuracy, such as:

1 Cold Start = 2 Warm Starts = 4 Hot Starts = 30 \times 60\% \text{ Load Changes}^{22}

Until the last decade, startup and related maintenance costs similar to those above have been determined almost universally by a “bottom-up” approach. This essentially involved looking at plant design conditions as well as assessing years of operating logs and maintenance work order bills to statistically divine how the number and type of startups likely impacted annual maintenance costs.

More recently, a complementary “top-down” methodology has been developed and refined. These less-expensive models use the past histories of operations, forced outages, and costs from multiple plants. These are coupled with extensive statistical modeling of thermal cycle stresses on the applicable plant’s health.\textsuperscript{28, 30}

These startup costs are based on detailed Aptech top-down analyses of an existing 360-MW coal boiler pressed into cycling service.\textsuperscript{29} The resulting fully rolled-up costs include all components from operators and maintenance wear and tear to startup fuel. These costs, shown in Table 2.3, have been prorated to an average 400-MW co-op coal boiler and total $173,000, $220,000, and $387,000 for a Hot Start, Warm Start, and Cold Start respectively. In contrast, the reported “significant” Load Follow Cycle is surprisingly inexpensive, at only $3,000.

<table>
<thead>
<tr>
<th>TABLE 2.2: Estimated Costs of Hot-Warm-Cold Startups.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Source: Energy Signature Associates</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>EPRI—Cycling of Fossil-Fueled Power Plants</td>
</tr>
<tr>
<td>EPRI—1,000-MW Coal Correlating Cycle Duty with Cost at Fossil-Fueled Power Plants</td>
</tr>
<tr>
<td>ETD—Damage to Power Plant Due to Cyclic Operation and Guidelines for Best Practices (UK Boilers)</td>
</tr>
</tbody>
</table>
## Table 2.3: Cost of Hot-Warm-Cold Startups and Load Following for a Co-op 400-MW Cycling Coal Boiler

Source: *Cost of Cycling Analysis for Xcel Energy’s Harrington Station Unit from Aptech*

<table>
<thead>
<tr>
<th>400-MW Coal-Fired Power Plant Cycle Costs*</th>
<th>Cost per Cycle (Thousand Dollars)</th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Hot Start Cycle &lt;12 hrs</td>
<td>Warm Start Cycle 12 to 72 hrs</td>
<td>Cold Start Cycle &gt;72 hrs</td>
<td>Significant Load Follow Cycle</td>
<td></td>
</tr>
<tr>
<td>E1: Cost of operation—includes operator non-fixed labor, general engineering and management cost (including planning and dispatch); excludes fixed labor</td>
<td>$14</td>
<td>$18</td>
<td>$33</td>
<td>$0.3</td>
<td></td>
</tr>
<tr>
<td>E2: Cost of maintenance—includes maintenance and overhaul maintenance expenditures for boiler, turbine, generator, air quality control systems, and balance-of-plant key components</td>
<td>61</td>
<td>77</td>
<td>139</td>
<td>1.2</td>
<td></td>
</tr>
<tr>
<td>E3: Cost of capital maintenance—includes overhaul capital maintenance expenditures for boiler, turbine, generator, air quality control systems, and balance-of-plant key components</td>
<td>40</td>
<td>51</td>
<td>92</td>
<td>0.8</td>
<td></td>
</tr>
<tr>
<td>E4: Cost of forced outages and derate effects, including forced outage time, replacement energy, and capacity</td>
<td>30</td>
<td>38</td>
<td>69</td>
<td>0.5</td>
<td></td>
</tr>
<tr>
<td>E5: Cost of long-term heat rate change due to cycling wear and tear</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.0</td>
<td></td>
</tr>
<tr>
<td>E6: Cost of heat rate change due to low load and variable load operation (process related)</td>
<td>3</td>
<td>3</td>
<td>4</td>
<td>0.1</td>
<td></td>
</tr>
<tr>
<td>E7: Cost of startup auxiliary power</td>
<td>1</td>
<td>1</td>
<td>3</td>
<td>0.0</td>
<td></td>
</tr>
<tr>
<td>E8: Cost of startup fuel</td>
<td>22</td>
<td>30</td>
<td>43</td>
<td>0.0</td>
<td></td>
</tr>
<tr>
<td>E9: Cost of startup (Operations—chemicals, water, additives, etc.)</td>
<td>$1</td>
<td>$2</td>
<td>$3</td>
<td>$0.0</td>
<td></td>
</tr>
<tr>
<td>Total incremental cost of cycling</td>
<td><strong>$173</strong></td>
<td><strong>$220</strong></td>
<td><strong>$387</strong></td>
<td><strong>$3.0</strong></td>
<td></td>
</tr>
</tbody>
</table>

* Prorated to an average 400-MW co-op facility. Costs are based on an extensive Aptech analysis of 2008 cycling costs at Texas Harrington 3, a 360-MW (gross) coal-firing steam-electric generating unit built by Xcel Energy in 1980. Cost data are for top-down results for all analyzed starts covering 2,851 net GWh from July 2007 through June 2008. Includes fatigue-creep interaction effects adjusted for signature data. (Numbers may not add due to rounding.) To access this study, do a Google search on the terms Aptech integrating wind.

### Cost of Cycling Summary

The maintenance costs associated with startup wear and tear are principally E2 and E3, as shown in Table 2.3. These total $101,000, $128,000, and $231,000 for a Hot Start, Warm Start, and Cold Start, respectively. In comparison, in Table 2.1, the estimated annual 25% EFOR unscheduled maintenance cost is shown as $4.7 million ($11,816/MW/yr @ 400 MW) for cycling operation. The annual scheduled outage cost is projected to add an additional $6.9 million, to yield a total annual Table 2.1 maintenance cost of $11.7 million.

A reasonable but not necessarily proven assumption would be that these startup wear-and-tear costs for cycling boilers from Table 2.3 are equivalent to Table 2.1’s unscheduled maintenance costs, plus some portion of the annual scheduled maintenance outlay. Using a 50% application of scheduled maintenance to startup costs, plus all of the EFOR costs in Table 2.1,
would total $8.0 million for an average co-op coal boiler. This would be the equivalent of 80 Hot Starts or more than 60 Warm Starts. Thus, the cycling cost estimates of Tables 2.1 and 2.3 appear to be in at least relatively reasonable agreement.

It is also worth noting Aptech’s conclusion as stated in EPRI’s Determining the Cost of Cycling and Varied Load Operations: Methodology report:

“From the day a unit begins operation, its aging profile is being shaped. That profile is determined by many things, but among the most important is how the unit is maintained and operated. It is not the incremental hot, warm, or cold start that has the major impact on that profile. It is the number of years the unit operates in one mode before switching to another (e.g., baseload versus cycling). Finally, and most important, is how maintenance is conducted at the unit. Far more damaging than any start to the equipment and materials is the stop because of a forced outage that has required the unit to come offline immediately without following the required protocol. Periods of history have demonstrated that, for this industry, the amount of damage and the cost of repairing the damage from frequent, severe forced outages is orders of magnitude greater than the damages and costs associated with cycling.”

Thus, as cycling occurs, forced outages also will occur, resulting in even more damage and frequent forced outages. The cycling costs in Table 2.3 range from $173,000 (Hot Start) to almost $400,000 (Cold Start) for a single dispatch cycle. These typify a co-op 400-MW baseloaded coal boiler pressed into cycling service. Moreover, the associated startup maintenance wear-and-tear costs are not inconsistent with the 25% EFOR unscheduled maintenance costs estimated for a cycling co-op coal boiler.

These costs are strikingly high and must be kept in mind when a co-op baseload boiler operation is shifted to cope with the cycling demanded by 30% wind renewables. It is equally important to note that, by comparison, a ‘Significant Load Following Cycle’ costs only $3,000 (Table 2.3). Clearly, co-ops should seriously consider load following as an alternative to a complete cycling shutdown when pressing a baseloaded coal boiler into wind-driven cycling service, if that is at all possible. The only alternatives will be to seek and install energy storage devices, such as Compressed Air Energy Storage or advanced batteries, or to install and run, with accompanying significant costs, fast-start and ramp-up aeroderivative combustion turbines (CTs).

A key part of managing a baseloaded coal boiler operating in conjunction with wind cycling is to understand which areas are likely to be impacted and how to mitigate those impacts. For those unfamiliar with the intricacies of a large coal-fired boiler, Figure 2.5 should prove helpful. A good primer on how this coal-fired steam generation facility works, and why its components exist, is the highly readable explanation in A Power Plant Primer.

Obviously, some components are more likely to be stressed when moving from baseloaded to cycling operation. These are highlighted in Figure 2.6, based on a sample of boilers in the United Kingdom that changed from baseloaded to ‘two-shifting.’ Two-shifting is a type of electric generation cycling common in the UK, where coal-fired units are operated for two shifts a day (about 16 hours of daytime operation) and then shut down for the remaining 8 hours. This operational change in UK coal facilities was due to changes in demand because of competition from nuclear, hydro, and gas-fueled facilities. The boiler failures due principally to cycling are shown in red. Headers in particular have been impacted. A header is a long, horizontal thick-walled tube with numerous welded penetrations connecting to boiler or superheater tubes. The metal pieces between these header tube connection holes are called ligaments. Some of these boilers have experienced 50% wall-depth ligament header cracking within 300 to 500 cycling
starts. Repairing this type of damage can be quite expensive and time-consuming. For example, a full-width superheater header can cost $1 million to replace; a full-width economizer header can cost $300,000. Table 2.4 tabulates some of the areas of concern when switching from baseloaded to cycling operation.22

Table 2.4 illustrates many of the issues that crop up when baseloaded coal plants are forced into cycling due to such causes as 30% wind renewables. This summary is based on pages 40 to 71 of the Damage to Power Plant Due to Cyclic Operation and Guidelines for Best Practices report available on CRN’s web site.22
Utility personnel whose interest in this issue is more than simply obtaining an overview can use that extensive and informative analysis rather than relying solely on the summary above. For the same reason, generating plant personnel should review those pages.

**TABLE 2.4: Concerns when Advancing from Coal Baseloaded to Cycling Operation.**
*Source: CEATI (2010)*

<table>
<thead>
<tr>
<th>Concerns</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crack-fatigue in thick wall components</td>
<td>Steam turbine rotors and casing</td>
</tr>
<tr>
<td>• Boiler and turbine stop valves</td>
<td>• Excessive loading and de-loading rates producing unacceptable clearances</td>
</tr>
<tr>
<td>• HP turbine inlet belts</td>
<td>• Sticking sliding surfaces and key ways</td>
</tr>
<tr>
<td>• Governor valves</td>
<td>• Cumulative rotor-critical speed vibration fatigue on blade roots</td>
</tr>
<tr>
<td>• Loop piping</td>
<td>• Steam impurity fouling</td>
</tr>
<tr>
<td>Superheater and reheater headers</td>
<td>• Stress corrosion</td>
</tr>
<tr>
<td>• Ligament cracking</td>
<td></td>
</tr>
<tr>
<td>Evaporator header stub cracking</td>
<td>Change in protective ash layers on superheaters and reheaters</td>
</tr>
<tr>
<td>Economizer header cracking</td>
<td>Air leaks into condensers during shutdown</td>
</tr>
<tr>
<td>Feed heater cracking</td>
<td>Generator ring integrity and stress corrosion on older units; insulation abrasion</td>
</tr>
<tr>
<td>Tube tie attachment lockups</td>
<td>De-aerator corrosion-induced cracking</td>
</tr>
<tr>
<td>Restrained pipework stays</td>
<td>Changes in furnace wall corrosion</td>
</tr>
<tr>
<td>Frozen boiler structure backstays and expansion joints</td>
<td>Water side corrosion, particularly in economizers, feedheaters, and evaporators</td>
</tr>
<tr>
<td>Scaling due to improper amounts of reagents in FGD systems</td>
<td>Moisture formation in electrostatic precipitators</td>
</tr>
<tr>
<td>Increased wear on standby and startup pumps</td>
<td>Increased amounts of thermal stress-induced fatigue</td>
</tr>
</tbody>
</table>

**Table 2.5: Key Facility Modifications to Consider when Converting Baseload Coal Boiler to Cycling Operation.** *Source: CEATI (2010)*

<table>
<thead>
<tr>
<th>Modification</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>Recognize and accommodate the fact that switching to cycling will greatly increase operation and maintenance personnel requirements, stress, and complexity.</td>
<td>Recognize and accommodate the fact that 30% wind will greatly increase dispatch complexity and stress.</td>
</tr>
<tr>
<td>Review existing facility operating procedures, sensor inputs, and practices. Consider adding additional sensors, particularly temperature, in key locations to monitor ramp rates and stresses. Understand that the response times to optimize operations when cycling are beyond the capability of human plant operators. Consider a major control upgrade to feed-forward systems with logic control subsystems such as: Lightup and Firing Control, Turbine Startup and Shutdown, Sliding Pressure Control, Preset Load Following, and Shutdown Sequences. Identify critical valves for remote automatic operation and live gland loading. Consider installation of a temperature ramp, stress, and damage effects monitoring software system. Also, consider additional periodic hand-held vibration and data monitoring.</td>
<td>Review and potentially implement Sliding Pressure Control as an additional tool to accommodate load variations and better control the number of costly damaging shutdowns and startups.</td>
</tr>
<tr>
<td>Improve boiler insulation to reduce cooldown between startups, including headers within dead spaces, as well as pipework, stop valves, turbine control valves, and turbine casings. As needed, control air leakage in air dampers and ash hoppers.</td>
<td></td>
</tr>
</tbody>
</table>

*Continued*
Table 2.5: Key Facility Modifications to Consider when Converting Baseload Coal Boiler to Cycling Operation (cont.). *Source: CEATI (2010)*

<table>
<thead>
<tr>
<th>Modifications</th>
<th>Considerations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Increase the capacity and operability of boiler drains to better enable progressive warming by controlled steam flows in boilers, steam legs, and turbines.</td>
<td>Develop enhanced operating and control practices to better avoid localized temperature stresses and overheating during startups and operation.</td>
</tr>
<tr>
<td>Improve startup burner reliability, stability, and turndown. Consider higher startup ratings to improve plant flexibility.</td>
<td>Add economizer and furnace off-load circulating pumps to reduce cooldown temperature gradients.</td>
</tr>
<tr>
<td>Consider boiler hot filling systems from an operating boiler, such as economizer inlet to economizer inlet, to reduce startup shock to related headers and ligaments.</td>
<td>Add inter-stage drains prior to platen sections to improve steam flow elsewhere in the boiler to prevent local overheating.</td>
</tr>
<tr>
<td>High rates of tube attachment failures have been a critical factor in cycling reliability. Consider converting to better designed or more reliable attachments.</td>
<td>Consider installation of an HP turbine bypass to permit startup steam flow through the cold reheat steam legs and into the reheat section.</td>
</tr>
<tr>
<td>Assess whether improved vacuum pump capacity is needed for faster startups.</td>
<td>Consider an auxiliary supply for steam sealing to turbine shaft glands to help vacuum raising.</td>
</tr>
<tr>
<td>Review existing welding practices where appropriate.</td>
<td>Consider increasing the capacity of the water treatment plant and related storage due to more drain losses during startup.</td>
</tr>
</tbody>
</table>

Table 2.5 extends this analysis. It highlights many of the key coal boiler facility modifications necessary to better cycle previously baseloaded coal facilities. These also are summarized in the aforementioned CRN report. That report views most of these upgrades to be relatively modest in cost, especially when viewed in light of their benefits to cycling operations and reduction in operation and maintenance costs incurred by boiler damage. The one exception may be needed control system upgrades to better manage cycling operations. Depending on the age of the existing system, such upgrades may cost $3 to $5 million.

The key sections of the *Damage to Power Plant…* report summarized in Table 2.5 are from its Section 5 (pages 79 to 100). In addition to Table 2.5, concerned plant management and operations personnel should read at least the entire Section 5, available on CRN’s web site.

It is encouraging to note that both the UK and American experience indicates that, with proper attention to details similar to those listed above, it is possible to cycle (or two-shift) coal-fired generating plants successfully. Moreover, response times can be improved with better control systems and practice. For example, Table 2.6 illustrates the improvement in response times at UK coal plants, although cold-start response times are longer because of the significant damage that cold starts have on a power plant.

The following section looks at some of the immediate next steps a co-op might undertake if cycling of coal baseloaded plants in response to a 30% wind is a possibility.
Cycling a formerly baseloaded coal boiler to respond to the variability of high amounts of mandated wind renewables is obviously a big change. It will require major modifications in dispatch and generation operations. It also will require extensive efforts by personnel and induce significant stress in what were previously rather uneventful job functions. The intent of this section is not to detail all of the applicable changes and upgrades but rather to suggest some more immediate preparatory—and then longer-term—implementation steps that should prudently be undertaken before initiating and better planning the total effort.

1. Review applicable mandated renewables requirements and assess the likelihood that disruptively high levels of wind generation will need to be accommodated. Estimate how long you will have to make needed changes in dispatch and the first round of baseloaded generation.

2. Undertake some internal rudimentary modeling, such as is illustrated in Figure 2.1, to get a feel for the likely impact of mandated wind renewables. If nothing else, Excel spreadsheets containing hourly load and wind data for various days are a useful start. One place to start is with the NREL wind data sets, which use actual weather data to simulate wind farm outputs. Also, an extensive library of wind-grid impact studies is available from the Utility Wind Integration Group, which also has some information on dispatch and forecasting impacts.

3. Review present wind offerings and contracts to see if anything can be done with respect to wind generation dispatchability or curtailability. However, this is somewhat akin to “squaring the circle,” because the likelihood that anything can be done with wind farm control to materially help cycling coal generation is slim to none. Recent ERCOT changes are aimed more at transmission issues than basic coal generation cycling.

While there are some small battery storage demonstration projects associated with wind, they are minimal compared to the requirements of a 400-MW cycling coal boiler. For wind storage to make sense relative to baseload cycling, the storage capacity probably would have to make up at least 50% of the connected wind capacity. Indeed, it might require a higher percentage. In fact, the only way to know with certainty about the major cycling impact on a baseloaded coal boiler would be to develop storage algorithms and then do a computer simulation based on the boiler size, wind farm capacity and outputs, and the proposed wind storage battery size. There are some interesting but embryonic developments in isothermal Compressed Air Energy Storage (CAES) technologies (no use of natural gas) with 75% efficiency, but their commercial use may be 3 to 5 years out. One company, General Compression, is currently developing General Compression Advanced Energy Storage (GCAES). The GCAES is expected to cost about $1,000/kW for 10 hours of storage in solution mined bedded salt, with each additional hour of storage costing only about $10/kW per hour.

4. Begin reviewing wind forecasting and baseload cycling issues with dispatch personnel. Develop a plan and timetable for acquiring needed capabilities. At a minimum, review the Texas ERCOT experience as a starting point. Also, consider Sliding Pressure Control and modified roles for Peaking and Intermediate Generation as potential aids in responding to base load coal-boiler dispatch and operation complexities.

5. Begin examining baseloaded coal boiler cycling issues with applicable management, operating, and maintenance personnel. Develop a checklist and a potential plan. Also, collect historic operating and maintenance data for applicable coal baseloaded units. A useful guide is CRN’s Damage to Power Plant Due to Cyclic Operations... Continue to consider Sliding Pressure Control as a potential load-following option to reduce dispatch, operating, and excessive startup stresses.

6. Begin planning for updated control systems at those baseloaded coal boilers most likely to be the first used for cycling operation.
Select a lead boiler as an experience work horse. At this boiler, with the aid of appropriate consultants, begin the updates by adding temperature recording and logging for key sections likely to be impacted by thermal cyclic temperature fatigue during startup and shutdown ramps.

These are Level 1 and possibly some Level 2 wear-and-tear sensors. EPRI can provide some guidance and information on software suppliers. A list is also given in Appendix E of Damage to Power Plant... At least for the first boiler, more than likely you will need to hire a consultant to help determine where and how these supplemental temperature sensors should be installed and logged at the boiler.

7. At the selected lead boiler, install a fully updated control and data system, including logic control subsystems, to acquire experience for ultimately updating other units.

8. Then install applicable equipment upgrades at the selected lead boiler, consistent with consultant assessments and Tables 2.4 and 2.5, to gain additional information and experience.

9. Continue to monitor the status and projections for wind renewables generation. Modify rollouts of dispatch improvements and baseload generation upgrades as appropriate.

Obviously, pressing baseloaded coal boilers into acceptable cycling service due to mandated wind renewables is not a trivial task. Neither are the dispatch issues. However, starting with the basic issues and working on a selected lead horse boiler are prudent actions. These steps should provide both the help and experience needed to cope successfully with wind-related complex dispatch and operating issues.

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### Is Energy Storage a Better Option?

A thousand megawatts of installed wind generating capacity would be needed to replace the average 400-MW co-op coal boiler. An obvious question is “Why not use electricity storage on the wind output to avoid all of the dispatch and cycling coal boiler issues?”

How much wind energy would need to be stored to make a useful impact on the 2,000-MW co-op having the typical 400-MW base-loaded coal boilers? Wind energy storage probably would need to provide capacity close to that of the 400 MW per boiler, storing electricity at that level for about 4 hours, thus containing 1,600 MWh of maximum storage fill. This would be released later, to help smooth wind variations and during low wind loads. On an overall annual basis, such storage would help to smooth about 15–20% of wind generation, but extensive computer model simulation would be needed to confirm this.

Actually, since the wind output variation could be up to 1,000 MW for a 400-MW renewables requirement, a safer wind storage specification might be 800 MW of input storage capacity with 3,200 MW-hours of storage—a very high level. The only storage technologies presently reaching these levels are pumped hydro and compressed air energy storage. The most promising technology mentioned previously is General Compression’s isothermal (no need for natural gas as fuel) GCAES, which is scheduled to be tested at 2 MW in summer 2011. Eventually, these modules will be expanded into 100-MW complexes, which are expected to cost about $1,000/kW for 10 hours of storage in bedded salt, with each additional hour costing $10/kW per hour of storage.

Regarding batteries, the largest U.S. unit is a 4-MW plant that stores 8 hours of grid power totaling 32 MWh, but this is far too costly. This Texas facility utilizes a large assembly of 600°F molten sodium-sulfur storage batteries. It costs around $25 million ($6,000 per kW), including the substation. Some analysts project an ultimate commercial cost of around $3,000 per kW, which is still too expensive.

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Continued
The other battery alternative is the use of pumped electrolyte flow units, such as vanadium redox or zinc bromide. Generally below 1 MW in size at present, Premium Power Corporation is pricing its batteries at about $2,000/kW for 7.4 hours of storage, but the efficiency currently is only 65%. Zinc Air Inc. is developing a Zinc Redox battery expected eventually to cost about $1,500/kW for >6 hours of storage and have an acceptable 78% efficiency.

Since all batteries are direct current devices, these systems need a rectifier to feed them and large expensive inverters to turn their stored DC power back into useful AC grid power. None is even close to the 100-MW level, let alone 400 MW. Generally, the use of any current storage technology other than pumped hydro or compressed air storage should be considered only as low-MW research and demonstration.

Illustrations of the expense of various storage concepts on a cost-per-kWh basis must add generation and wind costs. Storage also must include an annual cost of capital calculation and properly discount the value of future cycles. Also, a current generation flow battery storage cost must be added to wind costs to yield a true cost of wind-plus-storage.

Compared with the generally lower amount of the extra cost of cycling a coal boiler at double the O&M, it is difficult to see how wind storage will ever make economic sense just to eliminate most of the starts associated with cycling fossil plants, except that energy storage also can provide such things as an expensive frequency regulation service, a reduction in demand charge or capacity credit, T&D asset deferral, or energy arbitrage. In many cases, the energy storage system can simultaneously provide frequency regulation, demand charge reduction, or a capacity credit, and defer T&D assets, such as new lines or transformers, while smoothing out the variation in the load caused by the intermittency of wind generation. In some cases, these value streams can pay for a low-cost energy storage system. If not, the remaining cost of the energy storage system not paid by these streams of value may be low enough to offset the cycling damage costs and costs to upgrade previously baseloaded coal plants.

Pumped hydro generally is in the $1,500 to $3,000 per kW construction cost range but is greatly site-dependent. It also typically represents a massive project undertaking that uses reversible turbine-generators, which become storage motor-pumps. However, it is unclear whether the motor-pump portion would find a rapidly fluctuating and variable wind supply to be a suitable power input, and pumped hydro has many environmental regulatory challenges.

Furthermore, already expensive wind energy will become even more so when run through potentially costly add-on wind energy storage systems (unless other value streams are monetized, such as demand charge reduction or frequency regulation, to name a few). In comparison, cycling by slow load following a low bus bar-cost baseloaded coal boiler might be only 1¢ to 3¢ per kWh or more. Also, it must be noted that it is unlikely that cycling coal-fired boilers can reasonably be mitigated by anything smaller than wind power storage systems hundreds of MW in size.
The initial ERCOT wind grid emergency was reported in the *Dallas Business Journal* in link 1 below. This subsequently was analyzed in a much more technical post mortem, ERCOT Event, on February 26, 2008: *Lessons Learned*, by the NREL (found at link 2). Less noticed but equally important is the fact that the grid’s incremental power values (Lambda) are below zero for nearly 20% of the time in the western, wind-generation portion of the Texas grid. This means that the wind generators literally were paying the grid to take their power for approximately 20% of the time. This is covered in a National Wind Watch article, *Frequent Negative Power Prices in the West Region of ERCOT…* in link 3.

2. [www1.eere.energy.gov/windandhydro/pdfs/43373.pdf](http://www1.eere.energy.gov/windandhydro/pdfs/43373.pdf)

The principal source for state-by-state renewable requirements is the U.S. DOE EERE web site, link 4. Supplemental information can be found by clicking on specific states. Much more detailed state renewables information is at the DSIRE web site, found at link 5.

5. [www.dsireusa.org](http://www.dsireusa.org)

The baseline winter and summer co-op load profiles are from an extensive Tri-State Generation and Transmission Association generation planning filing to the Western Area Power Authority (link 6). The spring, summer, and weekend load profiles are adjustments derived from PJM grid data for the Dayton rural region (link 7).

6. [www.tristategt.org](http://www.tristategt.org)
The wind generation impact study for the ERCOT (Texas) grid is an excellent place to start in reviewing wind grid impacts. It is a well-organized and relatively easy to follow 146-slide presentation by GE. It comprehensively assesses all of the interdependent wind and generation issues and likely results. The GE ERCOT study can be accessed at link 8. A very comprehensive Western Region joint wind integration staged study is also almost complete. It spans the western Dakotas to southeastern California and from Wyoming down through New Mexico and Arizona. Containing multiple reports, it shows similar baseload coal boiler impacts (link 9). An extensive library of grid wind impact studies is hosted by the Utility Wind Integration Group. The library includes studies covering individual as well as multiple states, as well as international studies (link 10).

8  www.ercot.com/meetings/ros/keydocs/2008/0227/ERCOT_final_pres_d1_w-o_backup.pdf
9  www.westconnect.com/init_wwis.php
10 www.uwig.org/opimpactsdocs.html

There are a number of statistical analyses on wind power and its variation. One is an extensive NREL analysis of wind farm variability in the Minnesota region. This is covered in links 11 and 12. Many of the wind diversification results have been reported by a Carnegie Melon analysis of Texas wind farm sites (link 13). The GE ERCOT analysis also devoted significant analysis to the day-ahead prediction accuracy of wind and the resulting difficulty when load and wind prediction errors combine. This very critical area is covered extensively in link 14.

12 www.windonthewires.org/documents/Final_Report_2006_MN_Wind_Integration_Study_Vol_1.pdf
13 wpweb2.tepper.cmu.edu/ceic/theses/Warren_Katzenstein_PhD_Thesis_2010.pdf
14 www.ercot.com/meetings/ros/keydocs/2008/0227/ERCOT_final_pres_d1_w-o_backup.pdf

The principal data for installed renewables capacity is DOE’s 2009 Renewable Energy Data Book (link 15). Residential solar PV costs are reported by the California Energy Commission via Wind-Works at link 16. Solar water heating costs are from a CRN analysis, Solar Water Heating Best Practices and Economics (link 17). Co-firing biomass calculations are based on an unpublished CRN proposal, Develop a Key Biomass Co-firing Fuel Transport Guide plus an NREL state-by-state fuel resource analysis (link 18); a biomass co-firing retrofit capital cost analysis (link 19); and estimates of biomass collection, storage, and sales costs (link 20).

15 www.nrel.gov/docs/fy10osti/48178.pdf
16 www.wind-works.org/Solar/SolarPVCurrentInstalledPricesperkWnCaliforniaElsewhere.html
17 www.cooperative.com/about/NRECA/CRN/Results/Documents/SolarWaterHeatingBestPracticesandEconomics.pdf
18 www.nrel.gov/docs/fy06osti/39181.pdf
19 www.nrel.gov/docs/fy00osti/28009.pdf

The ERCOT analysis in link 8 provides a good place to start in understanding the impact of wind on dispatch and generation operations. More extensive information is at link 10. As a result of these types of impacts, including unresolved issues in link 3, ERCOT recently updated its wind generator requirements, as detailed in link 21. Probably by far the most definitive and useful report on the impact and mitigation of cycling on baseloaded coal-fired power plants is Damage to Power Plant Due to Cyclic Operation and Guidelines for Best Practices by ETD, a European firm. It has been secured by CRN for member use, via link 22. A relatively useful, but not overly technical, review of creep and fatigue modes and issues can be found at link 23. Aptech’s Power Plant Cycling Costs Incurred as a Result of Wind/Solar Integration covers the analysis and monitoring of cycling impacts on generation plants (link 24). Source data for the co-op generation fleet and boiler aging is from EIA’s Annual Generator Report database census (link 25).
Coal-fired boiler annual maintenance costs are based on EPRI assessment guidelines and reported in the NREL’s Cost and Performance Baseline for Fossil Energy Plants (link 26). Statistical reporting of various reliability and operating statistics, by NERC via Generating Unit Statistical Brochures, can be found in link 27.

A useful presentation is Aptech’s Power Plant Cycling Costs Incurred as Result of Wind/Solar Integration (link 28). This extensive top-down analysis for cost cycling a 360-MW coal-fired unit is Aptech’s Integrating Wind Cost of Cycling Analysis for Xcel Energy’s Harrington Station Unit 3 (link 29). A good companion analysis of top-down cycling modeling is in EPRI’s Determining the Cost of Cycling and Varied Load Operations: Methodology (link 30).

The overall schematic for a coal-fired boiler and electric generation facility can be accessed at link 31. A reasonably good, but not overly technical, primer on how a coal-boiler steam generator facility works, as well as its key components, can be found at link 32.

The NREL wind farm data sets contain simulations for wind farm outputs (link 33). Changes in recent ERCOT wind contracts, principally directed toward short-timed transmission needs, are reported in ERCOT’s Summary of Significant Wind-Plant Requirements (link 34). There are some small demonstration battery storage projects, such as in link 35, associated with wind farms at the 30% mandated renewables levels but these are not meaningful at the cycling coal-boiler level. EPRI has developed a well thought-out and comprehensive Cycling Operation of Fossil-Fueled Plants, Volume 6: Evaluation and Strategy, which can help serve as a useful guide and potential checklist (link 36). EPRI has some limited guidance on the installation of wear-and-tear instrumentation and provides information on software suppliers in its Feasibility of Wear and Tear Sensors for Flexible Plant Operations (link 37). Link 38 reports the completion of a 1-MW battery wind storage project in Minnesota.
Footnotes and additional sources for the sidebar on page 24:

www.cooperative.com/about/NRECA/CRN/Results/Pages/StorageTechnologies.aspx

www.energystoragecouncil.org/Septimus van der Linden ESC presentation.pdf

http://coen.boisestate.edu/WindEnergy/resources/ER-07-001.pdf


www.nooutage.com/hydroele.htm

http://bravenewclimate.com/2010/04/05/pumped-hydro-system-cost/