NATIONAL RENEWABLE ENERGY LABORATORY

Cost-Benefit Analysis of Flexibility Retrofits for Coal and Gas-Fueled Power Plants

August 2012 – December 2013

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Foreword and Legal Notices

This document was prepared by General Electric International, Inc. It is submitted to the National Renewable Energy Laboratory (NREL). Some of the findings in this study are published in a separate brochure, NREL/BR-6A20-60575, entitled *Flexible Coal: Evolution from Baseload to Peaking Plant*. Technical and commercial questions and any correspondence concerning this document should be referred to:

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Executive Summary

In the Electric Power industry, there is tremendous interest in investigating mitigation measures for lowering cycling-related costs of thermal power plants. One approach is to retrofit a few existing units for improved operational flexibility (i.e., capability to turndown lower, start and stop faster, and ramp faster between load set-points). While having this capability on some power plants might result in them cycling more, it will reduce the cycling on the remaining power plants in the system resulting in system-level savings. Having this operational flexibility will also help reduce the curtailment of wind and solar generation at higher renewable penetration levels. This report presents the findings of a study that examined the costs and benefits of retrofitting gas-fueled simple and combined cycle and coal-fueled steam turbine power plants for lower turndown, faster ramping, and faster starting capability. (Please also see the NREL brochure, BR-6A20-60575, entitled *Flexible Coal: Evolution from Baseload to Peaking Plant*).

First, the performance and cost information for a few operational flexibility retrofits available in the market for gas turbine (GT) and coal-fueled power plants was gathered. Next, a cost-benefit analysis was performed by running Plexos simulations with and without the retrofits on the selected power plants using the cost information. For this study, the units in the Rocky Mountain Power Pool (RMPP) system were studied for the year 2020. Since this system is predominantly coal-based, a "Modified-RMPP system" in which some of the coal units were converted to GTs was also studied. This study was performed under four different renewable penetration assumptions for the RMPP and Modified-RMPP systems.

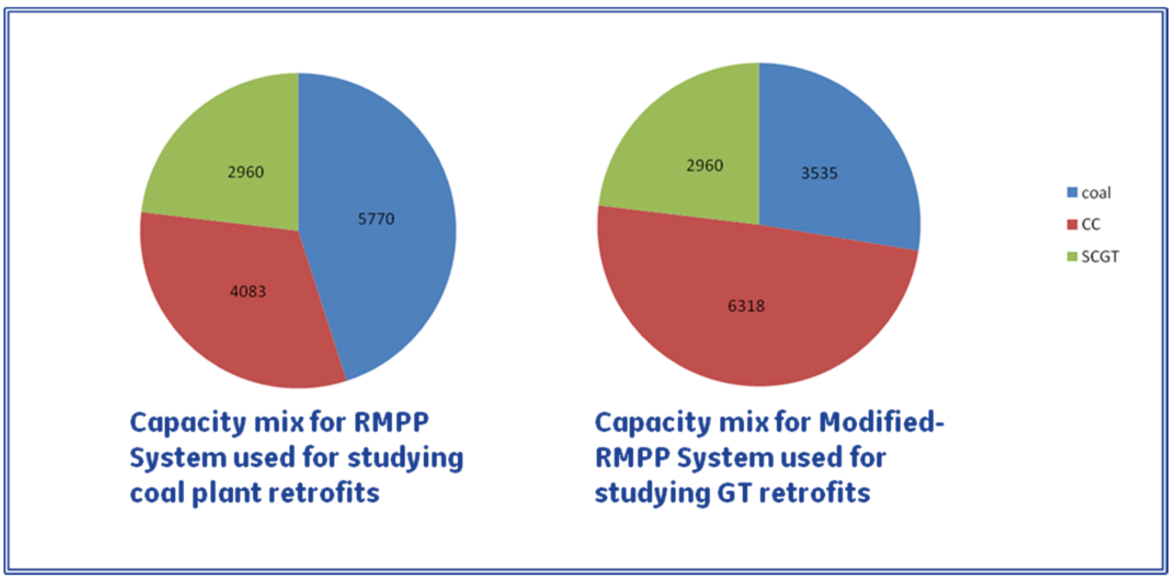

Figure 1. Capacity mix for the study systems

From the two simulations, the changes in system-level production costs, as well as changes to the retrofitted power plants revenues (i.e., the benefits) were determined. The results were then analyzed under two scenarios. Under the first scenario, the study system was assumed to be a vertically integrated utility under a cost-based return structure. In this case, the system-level production cost savings due to the retrofits were compared against the additional revenue required to cover the capital (and operating costs, if any) associated with the retrofits. A fixed charge rate (FCR) of 16% was used to convert the capital cost into annual revenue requirement. If the production cost savings were higher than the annual revenue requirements, the investment was deemed to have an economic merit.

Under the second scenario, the study system was treated as a deregulated market with merchant generation. The same results as those used in the regulated scenario were used in this analysis. However, in this case, for each generator that was retrofitted, the change in net revenue was compared against the cost of capital associated with the retrofit. The Net Present Value (NPV) associated with the cash outflow (capital investment) and cash inflows (annual net revenue increase/decrease) for a 20-year period were calculated. If the NPV was positive, the investment was deemed to have an economic merit.

The cost-benefit of the coal-fueled and gas-fueled power plants were studied separately in order to isolate their impacts. Although retrofits are available to improve turndown, ramp rate, and start up performance, the retrofits that primarily targeted turndown performance were studied since lower turndown capability was found to have the most beneficial impact on a system. Additionally, since it's neither feasible nor economical to retrofit all units for lower turndown, only a subset of units (around 25% of the capacity) was targeted for the retrofitting.

Study results show that at a system level, retrofits that improve the turndown levels of gas-fueled and coal-fueled power plants have a net-benefit to the system. The system-level net-benefit was determined by comparing the system production cost savings with the capital and operating costs associated with the retrofits. It should be noted that operational flexibility retrofits may not always result in a net-benefit to the system. For example, operational flexibility retrofits for gas-fueled, gas turbine power plants may not be of much value in a coal-dominated system with low coal prices. Conversely, coal plant retrofits may not be of much value in a gas-dominated system with low gas prices.

The results also showed that while there might be system-level net-benefits, there may or may not be a benefit at plant level. The plant-level benefit for a power plant that is retrofitted is its potential increase in net revenues. The study results showed that in a gas-dominated system, only one out of the three retrofitted power plants showed an increase in net revenue after the installation of the retrofit. Plant-level revenue impacts are particularly important in deregulated regions where generators make their retrofit decisions based on the potential for increased profits. Policymakers need to explore mechanisms to incentivize installation of retrofits so that they benefit systems and plant owners.

Introduction

High penetrations of wind and solar power plants can induce on/off cycling and ramping of fossil-fueled generators. This can lead to wear-and-tear costs and changes in emissions for fossil-fueled generators. Phase 2 of the Western Wind and Solar Integration Study (WWSIS-2) determined these costs and emissions and simulated grid operations to investigate the full impact of wind and solar on the fossil-fueled fleet. The study examined three high penetration scenarios with a nominal 33% wind/solar penetration across the U.S. portion of the Western Interconnection, resulting in 26% nominal penetration across the entire Western Interconnection.

The results of the study showed that wind and solar generation induces additional annual cycling costs of $35-157M. This same generation also displaces about $7B annually in fuel costs. The increase in cycling cost for the average fossil-fueled plant is $0.47 to $1.28 per MWh of fossil-fueled generation.[1] The cycling costs, although small from a system perspective when compared to the savings in fuel cost, are still substantial costs for the owners of these power plants. There is tremendous interest in the Electric Power industry—not only to quantify the cycling costs—but also to improve the cycling performance of the thermal units and to investigate mitigation measures for lowering cycling-related costs.

One approach for potentially mitigating the cycling costs is through operational strategies. This could involve the curtailment of renewable generation under certain conditions, shutting down expensive cycling units during certain periods, and/or alternate unit commitment strategies that take the cycling-related costs and emissions into account. An alternative approach is to retrofit existing units for improved operational flexibility (i.e., capability to turndown lower, start and stop faster, and ramp faster between load set-points). While having this capability on some units might result in them cycling more, it will reduce the cycling on the remaining units in the system, achieving system-level savings. Having this operational flexibility will also help reduce the curtailment of wind and solar generation at higher renewable penetration levels.

Some of the retrofit strategies that were explored in this study are as given below.

i. Retrofitting a certain percentage of the cycling fleet (primarily gas-fired combined and simple cycle power plants) with flex technology that allows:

   a. Lower turndown capability while adhering to emission limits

   b. Faster ramping capability

   c. Faster startup capability.

[1] "Western Wind and Solar Integration Study." (2013). National Renewable Energy Laboratory (NREL). Accessed September 2013: http://www.nrel.gov/electricity/transmission/western_wind.html.

ii. Retrofitting a certain percentage of the base load (primarily, coal and oil-fired steam turbine generators) fleet to improve flexibility such as:

    a. Combustion system optimization

    b. Coal mill design changes.

This report presents the findings of a study that examined the costs, as well as the benefits, of the retrofit strategies discussed above. The report is organized as follows:

Section 2 of the report discusses what operational flexibility means. Sections 3 and 4 discuss the flexibility retrofits available for gas-fueled simple/combined cycle gas turbine (GT) power plants and coal-fueled steam turbine power plants, respectively. Section 5 presents the details of the study system that was used in this study and Section 6 discusses the results of the cost-benefit analysis. Finally, Section 7 presents the conclusions of the study.

Operational Flexibility of Thermal Power Plants

As the penetration of renewable generation increases, the remaining generation fleet needs to be more flexible. The thermal power plants in the system will be required to start and stop more often, ramp faster between load set-points, and turndown to their minimum generation (frequently known as mingen or turndown) levels more frequently and stay at those levels longer. A prior NREL Study2 showed that the number of cold starts for thermal units increase by nearly 40% in a year, going from a system with no renewable generation to one with a 30% penetration of renewable generation for the WestConnect system. In the same study, the number of turndowns or large ramps for thermal power plants (i.e., the number of times a unit ramps by more than 10% from one hour to the next) more than double for the same case. It was also observed from this study that the thermal power plants spent significantly more time at their mingen or turndown levels.

The operating profile of a coal or gas steam and GT power plant under a high renewable penetration scenario is shown in Figure 2. In this figure, the generation from the power plant is shown on the y-axis.

[2] Jordan, G.; Venkataraman, S. (2012). *Analysis of Cycling Costs in Western Wind and Solar Integration Study*. Golden, CO: National Renewable Energy Laboratory. NREL/SR-5500-54864.

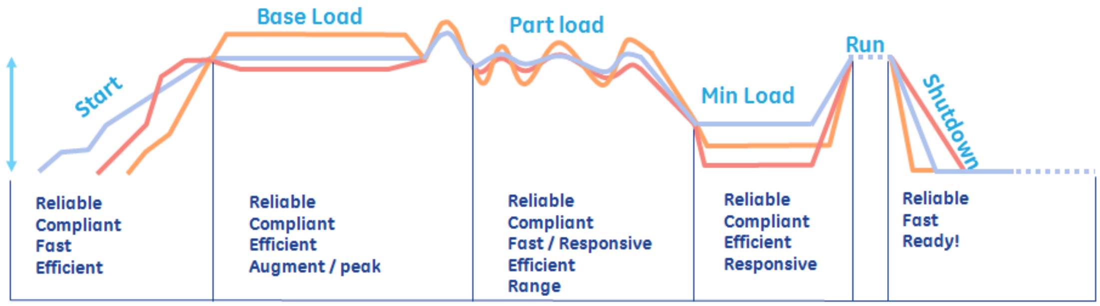

Figure 2. Contemporary power plant mission profile: spending less time at full load

There are several retrofit solutions available from Original Equipment Manufacturers (OEMs) which can make the thermal power plants more flexible over their entire mission profiles. In particular, the flexibility attributes that are of primary importance for integrating renewable generation are as follows:

- Lower turndown capability
- Faster ramping capability
- Faster and less expensive starts.

The next sections discuss the flexibility retrofits for gas-fueled simple and combined cycle GT power plants and coal-fueled steam turbine power plants.

Flexibility Retrofits for Gas-Fueled Simple and Combined Cycle GT Power Plants

This section discusses the operational flexibility retrofits that are available for GT power plants. Before discussing the retrofit solutions that are available to improve the operational flexibility of GTs, the reasons why these operational boundaries exist are also presented. Section 3.1 discusses the operational boundaries of a GT and the possible approaches to extend the boundaries. Section 3.2 discusses some of the specific operational flexibility retrofits solutions that are available from OEMs.

Operating Boundaries of a GT

The operating range of a GT is restricted by equipment design limitations coupled with externally imposed operating requirements.

Equipment design limitations are primarily driven by parts-life durability. More specifically, GTs are expected to be able to deliver a specified number of operating hours and startups between overhauls while maintaining a stated level of performance. The operating range of a GT may be increased further; however, there are mechanisms (such as peak firing) which have a tendency to increase variable operation and maintenance (O&M) costs. In some cases, these mechanisms may have an adverse impact on other parameters, such as heat rate. As a result, it is important to balance the benefits associated with increased operating boundary against the potential detriments to other characteristics for a given mechanism.

The externally imposed operating requirements may be imposed from either a regulatory perspective (i.e., emissions thresholds) or by the ambient conditions (i.e., outside temperature/humidity/pressure, fuel temperature/pressure/quality, grid frequency variability, etc.). In most cases, the operating range of a GT can be extended if the controllable subset of externally imposed requirements can be relaxed. For example, if the required emissions rate at lower loads is relaxed, the mingen (i.e., turndown) load level could likely be improved. Correspondingly, improvements in fuel quality can drive more aggressive emissions and performance guarantees. However, this may not be a parameter that is adjustable at a given location.

The following sections will further discuss key operating boundaries that are of contemporary interest and the driving force behind most operability enhancements: startup (time, emissions, and variation), ramp rate, and turndown. While the enhancements discussed in the following sections represent those adopted by GE, other OEMs may have similar approaches.

Startup

Flexibility-related improvements to GT/CC plant startup typically center on reductions in four key areas: (1) startup time, (2) startup emissions, (3) startup fuel cost, and (4) startup variation.

Startup Time

The typical GT startup involves several phases, such as a ramp-up from turning gear to purge speed, a purge cycle at 20-30% speed to expel volatile gases from the exhaust and Heat Recovery Steam Generator (HRSG), a light-off process, ramp-up to synchronization (i.e., breaker-closure) at full-speed / no-load (FSNL), and finally, a load ramp to the desired operating condition. For this discussion, the emphasis will be placed on heavy-duty GTs, which historically have yielded startup times of about 20-30 minutes for simple cycle operation. In combined cycle, the startup times vary as function of the thermal state of the bottoming cycle equipment (i.e., hot, warm, cold) at the desired time startup is to be initiated. The range for a typical combined cycle is on the order of 60-75 minutes (hot) – 4 hours for a cold-start. In the absence of a well-integrated digital control system (DCS) to assist with the startup, and more manual intervention, combined cycle power plant startup times can be significantly longer.

For simple-cycle applications, the solutions have focused on items such as:

- *Purge credit:* reducing or eliminating the purge[3] cycle, which saves time by allowing the purge to be completed at a more conducive time independent of the startup cycle. Specifically, this technique employs a purge on shut-down (or dedicated offline purge cycle) followed by the placement of an inert gas between the fuel supply and combustion system which prevents downstream leakage of fuel gases into the exhaust.

[3] Purge is the procedure of motoring the GT prior to introducing fuel so that all combustibles are removed from exhaust and HRSG.

- *Ignition "light-off" procedures:* these procedures[4] have been optimized to allow higher-speed ignition which save time by avoiding a coast-down from purge speed to light-off speed. In some cases, "fire-on-the-fly" technologies have allowed the hold-time prior to light-off to be eliminated completely.
- *Clearance management*: the limiting aspect for the acceleration and load-ramps is typically driven by compressor and turbine tip clearances, respectively. Due to the significant difference in the thermal-mass between the rotor and casing materials, the growth rate between the rotor and case pose the challenge of preventing "tip rubs" during transient events such as startup. To maintain high steady-state operating efficiencies, it's important for a GT to have tight tip clearances; however, this typically requires a more delicate and repeatable startup procedure. Improved analytical techniques, advanced controls systems, case and rotor temperature management methods, and enhanced materials technologies are all key aspects that have been deployed to aid in tip clearance management and allow more rapid startups.

On the whole, these types of approaches have allowed simple GT start times to be reduced by more than 50-60%.

For combined cycle applications, startup times are typically not limited by the GT. Instead, combined cycle startup times are limited by a series of hold-points that range from Steam Turbine (ST) temperature matching requirements to manage stresses and rub-risk, Heat Recovery Steam Generator (HRSG) stresses, and the risk of producing more steam via GT exhaust flow than the system is able to handle. Different techniques have been deployed by the various OEMs to improve the ability to start combined cycles more rapidly. These approaches have typically focused on either modification to the HRSG or steam bypasses around the HRSG to the condenser well, which help to de-couple the GT from the bottoming cycle during startup. Due to durability issues, OEMs do not typically pursue the use of bypass dampers for heavy-duty combined cycle applications. Further, most of the bottoming cycle advancements in startup time are available in new unit applications only due to the significant design integration that is required to achieve such benefits. Nonetheless, these procedures and equipment packages can allow combined cycle plants to reduce startup times by as much as 50%.

Startup emissions: in general, the faster startups will be accompanied by reduced emissions. This is driven by the fact that the combustion system is optimized for operation over the range from 50-100% load (for most heavy-duty products). As a result of the faster startup, the GT is more rapidly brought into an operating range that is coincident with its low-emissions design point. Reductions in NOx and CO on the order of 50% or more can be achieved with startup improvements.

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[4] Before the GT engine can run on its own power, the engine must be accelerated by an external source, such as a battery, to provide sufficient airflow to the combustor for ignition, typically referred to in the industry as light-off.

Startup fuel cost: for simple cycle units, the startup fuel cost can be reduced by 50-60% as a result of the faster startups. However, for combined cycle units, the potential for an increase in the fuel cost during startup is possible. This is driven by the fact that the GT is decoupled from the load ramp of the ST (still limited by stress and rub risks). So, while the GT is able to achieve full load more rapidly and operate very efficiently at low emissions, the overall plant will be operating at simple-cycle-like efficiencies until the ST output is available to dilute the variable cost. There are retrofits available which improve the ST responsiveness during startup. For the combined- cycle, there is certainly an upside in the rapid startup because the GT is able to produce substantially higher energy early on in the startup, allowing increased revenue capture.

Startup variation: additional emphasis has been placed on improving the repeatability of startup times of GT and CC power plants through the automation of startup procedures, equipment permissives, sensor technologies, etc. Such actions allow operators to initiate their startups at the most optimal time, reducing risk of having to buy replacement power in the energy spot market if they are late to meet dispatch commitment.

Often related, the cost of cycling a unit is the minimum uptime and downtime constraints of the asset. Typically, the minimum uptimes and downtimes are driven by a desire to minimize thermal stresses in the casing and rotor components coupled. Further, the risk of a clearance rub-out due to the mismatch in the growth characteristics of the rotor and casing components is often the limiting factor in establishing a minimum down-time set-point.

Ramp Rate

There are several different aspects which are important to consider when characterizing ramp rates. For example, most GTs have both a nominal and emergency load rate. For primary (governor) response, the GT load rate can be substantially higher. However, in the context of flexibility, the discussion is usually focused on the nominal load rate because it will be leveraged on a more continual basis. Ramping may be required to support the regulation ancillary service which sends "output raise/lower" pulses every 3-6 seconds and has the potential change sign (+/-) between pulses. Use of the emergency load rates for regulation service would add stress to the hardware and substantially elevate maintenance costs.

To support ramping, the control system and hardware need to be nimble. Two of the key items which limit the ramping capability are: (1) combustion processes and (2) hardware stress. When ramping, the combustion system is operating in a transient condition. For gaseous (compressible) fuel units, (particularly Dry Low NOx (DLN) pre-mixed combustion systems), the fuel-air ratios during steady-state operation are incredibly low. Sustaining the combustion process during transients is even a greater challenge. During ramping events, both fuel flow and airflow are fluctuating simultaneously. Maintaining adequate blow-out margin (i.e., avoiding a fuel-air ratio that is too low) and remaining in emissions compliance (i.e., proper fuel-air mixing and not running too rich of a fuel-air ratio) is an even greater challenge. Further, the ramping can elevate combustion dynamics, which induces hardware-damaging pressure pulses. All of this needs to be managed properly to ensure reliable operation. The rapid increase/decrease of firing temperature can further add stress to the hardware during ramping events.

Turndown

Many combined cycle plants built in the U.S. during the early 2000s were built for baseload operation and not continuous operation at part load. The smaller HRSG attemperation systems in the plants cannot supply enough spray to handle the high exhaust temperature and low flow conditions during part load. This plant limitation can greatly impact overall GT turndown, allowing only a turndown of 70% versus 40-50% normally. With the desire to increase the penetration of renewables, more emphasis has been placed on the ability for GTs to operate at lower load levels while maintaining emissions compliance (i.e., turndown capability). The deeper turndown capability allows GTs to avoid cycling costs (both startup fuel and variable O&M penalties), but also provides opportunities for the GTs to garner ancillary payments for services such as regulation and spinning reserve.

There are several challenges with improving the ability for a GT to reduce its emissions-compliant minimum load set-point. Typically, the threshold is driven by CO compliance. As load is reduced, the combustion temperatures come down as well. While NOx is typically reduced at low loads, the reduced temperatures are unfavorable for CO and the emissions increase. There are several techniques that can be used to improve the turndown capability; most of these seek to increase combustion temperatures which reducing combustor airflow. Options such as a bypassing compressor discharge air around the combustion system; these have been investigated by multiple OEMs and are increasingly available on new units and retrofit offerings. Unfortunately, most of these techniques detract from the efficiency at the minimum load level as they introduce a thermodynamic penalty to compensate for an emissions constraint.

The next section discusses specific operational flexibility retrofits that are available from OEMs such as GE for improving turndown, startup, and ramp rate performance.

Operational Flexibility Retrofits for GTs

This section discusses the advanced controls solutions offered by one OEM for improving the operational flexibility of GT units. Additional details regarding these solutions are included in Appendix A. While the retrofits discussed are based on one OEM's offerings, similar retrofit solutions may be available from other vendors.

The operational flexibility solutions from this OEM are categorized by the segment of the mission profile that they impact. For example, the solutions distinctly target four segments: (1) startup, (2) full load, (3) part-load, and (4) minimum load. The respective solutions and corresponding applications for three relevant segments are described in more detail below.

The startup-related operational flexibility solution targets a fast, reliable, and repeatable startup profile. Specifically, the underlying applications target reductions in startup time and corresponding startup variability along with reduced emissions. For example, the OEM's solution employs a "purge credit" system which moves the startup purge to the prior shutdown, plus faster acceleration and loading rates to achieve near baseload output in 10 minutes in simple cycle applications. The startup operational flexibility solution results in a 50%-60% reduction in startup time combined with 50%-70% reduction in startup emissions.

The part-load-related operational flexibility solution focuses on the part-load regime offering improved responsiveness, efficiency, customer-controlled emissions, elevated loading rates, and automated combustion system tuning. For example, the OEM's solution enables load ramping up to twice the normal rate, such that the full mingen to baseload range can be covered in less than five minutes. As much as a 50% improvement on a MW/min basis can be obtained through this solution.

The minimum load-related operational flexibility solution enables lower emissions and promotes minimum fuel use at the turndown condition. The associated applications reduce overall fuel consumption, yield reduced emissions, and facilitate improved dispatch priority. For example, the OEM's solution extends low emissions operation to lower load levels, improving the economics to remain online overnight and avoid shutdown and startup costs. It also extends the available load range for operation, improving dispatch flexibility and enabling greater participation in regulating reserve markets.

The operational flexibility solutions discussed above are primarily focused on improving the performance of GTs through changes in the control software. For a combined cycle power plant, there may be other avenues for improvement in operational flexibility. These include changes in the design of the Heat Recovery Steam Generator (HRSG), steam turbine, and the Balance of Plant (BOP). Some of the newer combined cycle plants achieve flexibility by breaking the link between the GT and steam turbine cycle. However, the focus of this study was on the GT retrofit solutions.

Table 1 through Table 3 show the typical performance improvements that can be expected, as well as the associated costs from retrofit solutions that target turndown, startup, and ramp rate performance, respectively. These tables show the performance improvements for both simple and combined cycle power plants by GT frame type (B, E, and F). A discussion of the different GT frames is included in Section 5.2. This data was obtained by analyzing the retrofit solutions that addressed 18 operational characteristics such as startup time, emission reduction, and turndown improvements for nearly two dozen GT models. Since a retrofit solution may have multiple benefits (for example, a retrofit solution that improves the startup time may also have a secondary benefit of improving the ramp rate performance), the cost associated with a specific benefit (startup time, in this case) was obtained by apportioning the total cost of the solution to all the benefits from that solution (i.e., startup time, ramp rate). This was done so that the cost-benefit of improving turndown, ramp rate, and startup performance can be studied separately. Therefore, the cost ranges shown in the tables are not commercial prices, but representative prices to be used in the study. It should be noted that in reality there may not be a retrofit solution (and corresponding price) that targets a single operational characteristic such as turndown.

In the tables below, the expected performance improvement is shown as a percentage of existing default performance values. For example, with the ramp rate retrofit, a 100% increase (doubling) of ramp rate over existing ramp rate can be expected as shown in Tables 1through 3.[5]

Table 1. Performance and Cost Information for Turndown Improvements

	Simple Cycle			Combined Cycle		
	B Frame	E Frame	F Frame	B Frame	E Frame	F Frame
Targeted Turndown Improvement	5%	5%	10%	5%	5%	10%
Price Range	120K-180K	160K-240K	400K-600K	120K-180K	160K-240K	400K-600K

Table 2. Performance and Cost Information for Startup Improvements

	Simple Cycle			Combined Cycle
	B Frame	E Frame	F Frame	F Frame
NO_X Emission Improvement			54%	54%
CO Emission Improvement	50%	50%		
CO_2 Emission Improvement	66%	66%		69%
Startup Fuel Improvement	66%	66%		31%
Startup Time Improvement	50%	50%	59%	59%
Price Range	240K-360K	240K-360K	800K-1200K	1,320K-1,980K

Table 3. Performance and Cost Information for Ramp Rate Improvements

	Simple Cycle	Combined Cycle
	F Frame	F Frame
Ramp Rate Improvement	100%	100%
Price Range	400K-600K	400K-600K

[5] Note: The cost ranges shown in the tables are not commercial prices, but representative prices to be used in the study.

Flexibility Retrofits for Coal-Fueled Steam Turbine Power Plants

This section discusses the operational flexibility retrofits that are available for coal-fueled power plants. Similar to the GT units, there are operational boundaries on the coal-fired generation. Moreover, most of the coal generation was built for baseload operation and few units have been designed for cycling. Section 4.1 discusses the operational boundaries of a coal-fired unit and the possible approaches to extend the boundaries. Section 4.2 discusses some of the specific operational flexibility retrofit solutions that are available to asset owners.

Operating Boundaries of Coal Units

Providing generation flexibility requires lower and efficient part loads, faster ramping times, and short startup times. Most existing coal steam plants were not designed specifically for this flexible operation, but were instead intended to provide steady baseload generation. The operating range of a coal unit is restricted by equipment design limitations coupled with externally imposed operating requirements.

Coal (as well as gas) steam unit operating boundaries are typically related to fuel handling, the boiler, the steam turbine, the controls, and the BOP equipment design limitations. While, operational as well as design modifications can improve the operational flexibility of the units, a number of factors can in fact have an adverse effect on plant economics. For example, at lower load operation, the unit heat rate efficiency is lost. Heat rate deterioration can be caused due to any number of factors, including steam flow, efficiency of the turbine steam path, steam conditions, and the performance and operation of the BOP components. However, running the coal units at lower loads for extended hours can in fact lower component damage (creep) due to lower temperature. As a result, it is important to balance the benefits associated with increased operating boundary against the potential detriments to other characteristics for a given mechanism.

On the other hand, externally imposed operating requirements may be imposed from either a regulatory perspective (i.e., emissions thresholds) or by the ambient conditions (i.e., outside temperature/humidity/pressure, fuel temperature/ pressure/quality, grid frequency variability, etc.). Similar to GTs, the operating range of a coal plant can be extended if the controllable subset of externally imposed requirements can be relaxed. For example, if the required emissions rate at lower loads is relaxed, the mingen (i.e., turndown) load level could likely be improved. Several coal-fired units have gas igniters. At startups as well as low loads, these units can switch to gas for MW generation, thus reducing emissions. Correspondingly, improvements in fuel quality can drive more aggressive emissions and performance guarantees; however, as in the case of GTs, this may not be a parameter that is adjustable at a given location.

The following sections will provide further discussion on key operating boundaries that are of contemporary interest, and correspondingly, the driving force behind most operability enhancements: startup (time, emissions, and variation), ramp rate, and turndown.

Startup

Flexibility-related improvements to coal plant startup typically occur through reductions in four key areas: (1) startup time, (2) startup fuel cost, (3) startup emissions, and (4) startup variation.

Startup Time

A typical small or large subcritical coal unit can take several hours for a startup. Coal unit startup has additional complexity than, for example, simple cycle combustion turbines. With a time-based classification, the shutdown/ startup event is classified by the number of hours the unit has been off-load prior to the startup. For medium sized units a commonly used time classification is:

< 8 hours off-load = hot start

8 to 48 hours off-load = warm start

> 48 hours off load = cold start.

In most cases, for large units these time values will be higher. Traditionally, the turbine casing temperature decay from a hot to ambient condition is used to determine the start types. Unfortunately, these time-based and high pressure steam turbine casing metal temperature-based startup classifications do not adequately classify the startup type with respect to the boiler's thick-section pressure parts or other boiler components, which generally cool down much faster than the high pressure steam turbine casing. A hot or warm start on the turbine might be a cold start on the boiler. In general, a cold start is more damaging than a warm or hot start due to the excessive temperature differentials on the components.

It should also be noted that the cooling behavior of the boiler and drum can vary widely, depending on the shutdown procedure and how the procedure affects the preservation of drum pressure and furnace gas temperature, and the circulation of fluid into the drum either from the feedwater/economizer or throughout the waterwall circuits. In general, maintenance shutdowns tend to be more rapid than dispatch-related shutdowns—unless the operators have grown accustomed to only using a single shutdown procedure.

Purge time, fuel/air burner sequence, timing, flow, drain sequence, valve opening sequence, and a bypass system as well as attemperation can help to reduce startup times. Additionally, design retrofits such as auxiliary boilers can help keep components hot, and therefore reduce startup times. However, there are both positive factors which can reduce the damage to boiler components and potential pitfalls with each of the operational or design modifications to reduce start times.

<u>Startup Fuel Cost</u>: Unlike simple cycle gas units, coal steam units have slightly lower flexibility in reducing startup fuel costs. However, certain procedures such as coal drying can reduce pulverizer startup costs. For example, Ontario Power Generation was designed for low-sulfur bituminous coal, but switched to Powder River Basin (PRB) coal,

resulting in reduced heat available to the pulverizers.[6] Plant management decided to install natural gas-fired duct heaters to raise the Primary Air. While using gas on startups can become expensive depending on prevailing natural gas price, in today's scenario there may be marginal benefits to startup fuel costs.

Startup Emissions

Using gas igniters on startup can help units reduce emissions on startups. In general, the faster startups will be accompanied by reduced emissions. However, fuel quality on coal units particularly impacts startup emissions. Due to the inherent moisture in sub-bituminous and lignite coals, all else being equal to a bituminous coal-fired boiler is more efficient than a corresponding boiler burning sub-bituminous or lignite coal.

Ramp Rate

There are several different aspects which are important to consider when characterizing ramp rates. Coal units can have ramp rates of 1MW/min to 10 or 12 MW/min depending on size and control technology at the operator's disposal.

Several factors impact ramp rates on steam units, including the fuel quality variation, which can have a significant impact on ramping capability. Fuel quality variation directly corresponds to temperature variations, thus making MW change more difficult. The control of boiler parameters is more challenging with ramping, often resulting in increasing variability of waterwall outlet temperatures. While control systems allow operators to vary fuel to air ratio and control rate of change of energy, hardware such as the pulverizers play an important role in improving ramp rates.

Further, the ramping can elevate combustion dynamics which induces hardware damaging pressure pulses. All of this needs to be managed properly to ensure reliable operation. The rapid increase/decrease of firing temperature can further add stress to the hardware during ramping events.

Turndown

With the desire to increase the penetration of renewables, more emphasis has been placed on coal units' ability to operate at lower load levels. With market deregulation, the traditional dispatch philosophy was focused on short term benefits of reduced fuel costs. However, several utilities and asset owners are now considering the impact of cycling on maintenance and life of the plant. Low load operation affects the boiler combustion process. The primary constraint on coal units, especially pulverized coal units, is the turndown of pulverizers and risk of a unit trip with minimum mills in service without support fire--from gas or other sources. Without gas support, most units are limited to a low load of no less than about 40-50% of the rated capacity of the unit. These limits vary from site to site, and are constrained by design of the asset and by external factors such as emissions regulations.

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[6] "Coal Plant O&M: Coal Drying Reduces Pulverizer Start-up Costs." (2007). *Electric Power*, 2007. Douglas J. Smith, IEng, Contributing Editor. Accessed 2012: http://www.powermag.com/coal-plant-om-coal-drying-reduces-pulverizer-start-up-costs/.

Modern control systems, along with sliding pressure procedures or variable pressure operation, can assist asset owners with turndowns without significant efficiency or wear and tear cost penalties. Sliding pressure offers advantages over throttle control during startup as well as part load operation. Units where the control system is limited to fixed-pressure operation should consider retrofitting the plant to sliding-pressure operation. While there may be efficiency losses with low load operation on the boiler, a recent case study showed that the turbine can sometimes be a limiting factor. At low loads, turbine blade fluttering is possible, which can again limit the turndown on the unit.

The next section discusses specific operational flexibility retrofits for improving turndown, startup, and ramp rate performance.

Operational Flexibility Retrofits for Coal Plants

As in the case of GTs, the operational flexibility solutions can be categorized by the segment of the mission profile that they impact--(1) startup/shutdown, (2) ramp rates, and (3) part-load and (4) minimum load. The respective solutions and corresponding applications are described in more detail below.

The startup operational flexibility retrofits target reductions in startup time and corresponding startup variability, along with reduced emissions. However, startup retrofits have a larger impact on startup times, with a smaller impact on emissions. Some of the retrofits considered in this study can positively impact startup times by 50%. In most cases these retrofits also benefit shutdown on units. Turbine, BOP retrofits, and improved controls provide the most benefit and can sometimes improve startup/shutdown times by 100%. In terms of the emissions equipment, heated precipitators can improve both part load operations and startups.

The part-load operational flexibility focuses on the part-load regime, offering improved responsiveness in terms of ramp rates, efficiency, and elevated loading rates. The minimum load operational flexibility solution enables lower emissions and promotes minimum fuel use at the turndown condition. In fact, allowing coal-fired units to avoid increased on/off starts by lowering their minimum loads will reduce overall wear and tear costs and damage. Larger units have typically limited their low load operation to 40% of their capacity. Most of the constraints are boiler and mill stability-related. Low load gas igniters alone can provide a significant impact to low load operation and reduce minimum loads to 25% of maximum rating or lower.

Tables 4 – 9 show the performance and cost information for retrofitting different systems in the coal steam units for improved turndown, startup, and ramp rate performance. Additional information about these retrofits can be found in Appendix B, as well as the separately published brochure entitled *Flexible Coal: Evolution from Baseload to Peaking Plant* (NREL/BR-6A20-60575). The estimates for expected benefit from various flexible operation characteristics provided in the tables are generic. Almost always, these costs will vary based on plant design and location as well as financial and contractual agreements. In these tables, the cost estimates are shown for small subcritical, large subcritical, and supercritical coal-fueled power plants. The expected benefits are the end states that can be achieved with the retrofit.[7]

The tables provide cost estimates for several hardware retrofits that may provide benefits to more than one aspect of flexible operation. In most situations, keeping components hot can significantly reduce the thermal fatigue damage associated with cyclic operation. Occasionally, a single retrofit option may only impact one flexible operation mode. For example, turbine electric heating blankets provide a significant improvement to start/stop cycling, but may not benefit other flexible operating modes measurably.

[7] Please note that the impact of the retrofits solutions for GTs is presented differently in Section 3.2. For GTs, the additional improvements (not the end state) that can be achieved by retrofit solutions are shown in Tables 3-1 to 3-3.

Table 4. Performance and Cost Information for Boiler Retrofits

Retrofit Options	Cost to Install in Millions			Expected Benefit:		
	Small Sub Critical Coal 200MW	Large Subcritical Coal 500MW	Supercritical Coal 750MW	Ramp Rate	Turndown	Startup/ Shutdown
Improved and automated boiler drains	$ 3.00	$ 5.00	$ 5.00		50%	50%
Steam flow redistribution and metallurgy improvements in in SH/RH	$ 2.50	$ 5.00	$ 7.00	33%	33%	33%
Steam coil air heater to pre warm boiler and airheater	$ 0.50	$ 1.00	$ 2.00	33%	33%	33%
Gas bypass to keep air heater warm	$ 0.70	$ 1.50	$ 3.00		50%	50%
Improved APH basket life when cycling in or through the wet flue gas temperature region by installing traveling APH blowers to remove deposits prior to cycling down in load	$ 0.75	$ 1.00	$ 1.00		50%	50%
Improved APH basket life with improved materials when cycling in or through the wet flue gas temperature region	$ 1.20	$ 2.00	$ 2.00		50%	50%
Improved selected expansion joints. This is not a complete replacement of all expansion joints.	$ 1.50	$ 2.00	$ 3.00			100%
Add steam cooled enclosure min flow protection for balanced flow with blow down or dump to LP turbine	$ 0.30	$ 0.50	$ -		50%	50%

Table 5. Performance and Cost Information for Coal Mill Retrofits

Retrofit Options	Cost to Install in Millions			Expected Benefit:		
	Small Sub Critical Coal 200MW	Large Subcritical Coal 500MW	Supercritical Coal 750MW	Ramp Rate	Turndown	Startup/ Shutdown
Improved flame proving equipment for burners	$ 0.50	$ 1.00	$ 1.50	33%	33%	33%
Low load gas ignitors to allow min generation on gas fuel only	$ 2.00	$ 3.00	$ 4.00		100%	
Dual Fuel burners – use NG over coal (Add NG to all burners). Gas supply is not included	$ 10.00	$ 12.00	$ 16.00	33%	33%	33%
New feeders with gravimetric type feeder with improved weighing of coal feed to mill	$ 3.60	$ 7.20	$ 10.00	33%	33%	33%
Automatic pressure control on roll and race to adjust the grinding pressure of the coal mill.	$ 3.00	$ 5.00	$ 7.00	33%	33%	33%

This report is available at no cost from the
National Renewable Energy Laboratory (NREL)
at www.nrel.gov/publications.

Table 6. Performance and Cost Information for Emissions Control Retrofits

Retrofit Options	Cost to Install in Millions			Expected Benefit:		
	Small Sub Critical Coal 200MW	Large Subcritical Coal 500MW	Supercritical Coal 750MW	Ramp Rate	Turndown	Startup/ Shutdown
Heated precipitator hoppers	$ 0.50	$ 1.00	$ 1.80		50%	50%
New dry fly ash transport	$ 2.00	$ 3.00	$ 4.00		50%	50%

Table 7. Performance and Cost Information for BOP Retrofits

Retrofit Options	Cost to Install in Millions			Expected Benefit:		
	Small Sub Critical Coal 200MW	Large Subcritical Coal 500MW	Supercritical Coal 750MW	Ramp Rate	Turndown	Startup/ Shutdown
Small package boiler, electric boiler with air modeling and permit	$ 3.20	$ 4.00	$ 6.00		50%	50%
Motor driven boiler feed pump with startup to min load capability	$ 4.00	$ 6.00	$ 8.00		50%	50%
Improved vibration sensing and monitoring of all rotating equipment	$ 1.50	$ 2.50	$ 3.50	33%	33%	33%
Speed Controlled motors on ID and FD fans using variable frequency drives	$ 5.00	$ 7.50	$ 7.50	33%	33%	33%
Transformer monitoring gas analysis and temperature and emergency oil removal if arching occurs	$ 0.57	$ 1.50	$ 2.25	33%	33%	33%

Table 8. Performance and Cost Information for Turbine Retrofits

Retrofit Options	Cost to Install in Millions			Expected Benefit:		
	Small Sub Critical Coal 200MW	Large Subcritical Coal 500MW	Supercritical Coal 750MW	Ramp Rate	Turndown	Startup/ Shutdown
Turbine electric heating blankets	$ 1.00	$ 2.00	$ 2.50			100%
Convert 3 rpm to 40 rpm turning gear motor to prevent blade attachment wear and generator loose parts	$ 0.75	$ 1.50	$ 2.00			100%
New valve operators Full arc emission/sliding pressure	$ 1.00	$ 1.80	$ 4.00	33%	33%	33%
Turbine drains to the condenser hot well including main steam drains and before seat warmup drains should be routed to the hotwell with a sparger discharge below the normal water level.	$ 0.25	$ 0.50	$ 0.75			100%
Turbine water Induction prevention Upgrades including MOVs on extractions and inspection of heater drains and extraction piping and bellows in condenser	$ 0.50	$ 0.75	$ 1.00	33%	33%	33%
Condenser tube shielding	$ 0.50	$ 0.75	$ 1.00		50%	50%

Table 9. Performance and Cost Information for Chemistry-related Improvements

Retrofit Options	Cost to Install in Millions			Expected Benefit:		
	Small Sub Critical Coal 200MW	Large Subcritical Coal 500MW	Supercritical Coal 750MW	Ramp Rate	Turndown	Startup/ Shutdown
Nitrogen Blanketing of condensate storage tank, Boiler, turbine	$ 1.00	$ 2.00	$ 3.00			100%
Condensate polishing system for rapid water chemistry cleanup when cycling	$ 1.25	$ 2.00	$ 3.00		50%	50%
Larger condensate storage tanks	$ 1.50	$ 3.00	$ 4.00			100%
Add steam cooled enclosure min flow protection for balanced flow with blow down or dump to LP turbine	$ 0.30	$ 0.50	$ -		50%	50%

Flexibility Improvements from Operating Procedures

Finally, it must be noted that significant improvement to cycling operation can be achieved through operational changes alone. Units with increased cycling operation should typically increase the frequency of scheduled inspections or replacements for the components susceptible to damage. While the increased frequency of inspections can add costs to operate, the benefit of increased reliability will help asset owners mitigate the risk associated with cycling units. Some other examples of operating procedure changes include:

- Pre-warming/DA system, pegging steam on the Low Pressure (LP) heater or the top LP heater using boiler feed pump recirculation with a temperature control system. These can be low cost improvements for mingen and startup benefits.
- Boiler optimization using revised procedures for cycling the plant, which can have major improvements to ramp rates and mingen operation as well as start/stop cycling.
- Enforcing operating guidelines for layup procedures. Depending on the plant offline period, the dry or wet layup procedures should be defined. For example, for a quick shutdown (hot start, < 24 hours), the boiler, deaerator can have a wet layup with nitrogen and a vacuum on the turbine to prevent damage.
- Modifying and following cycle chemistry guideline limits during plant startup, shutdown, and layup.
- Improving Selective Catalytic Reduction (SCR) inlet temperatures to mitigate low load operation issues at the SCR.
- Operator training to reduce and monitor damaging trends while operating in cycling mode.

A related case study on the capital and operational changes made to a coal power plant to enable it to go from a baseload unit to a super-peaking unit is included in the brochure entitled *Flexible Coal: Evolution from Baseload to Peaking Plant* (NREL/BR-6A20-60575).

Study System for Retrofit Analysis

The impact of the retrofits on the production cost of the system, as well as the revenues earned by units was studied using the Plexos simulation model. For this study, the units in the RMPP system were studied for the year 2020. Figure 3 shows the major thermal units in this system. Since this system is predominantly coal-based, a "Modified-RMPP system" in which some of the coal units were converted to GTs, was also studied. This section gives the major assumptions for the RMPP and Modified-RMPP systems.

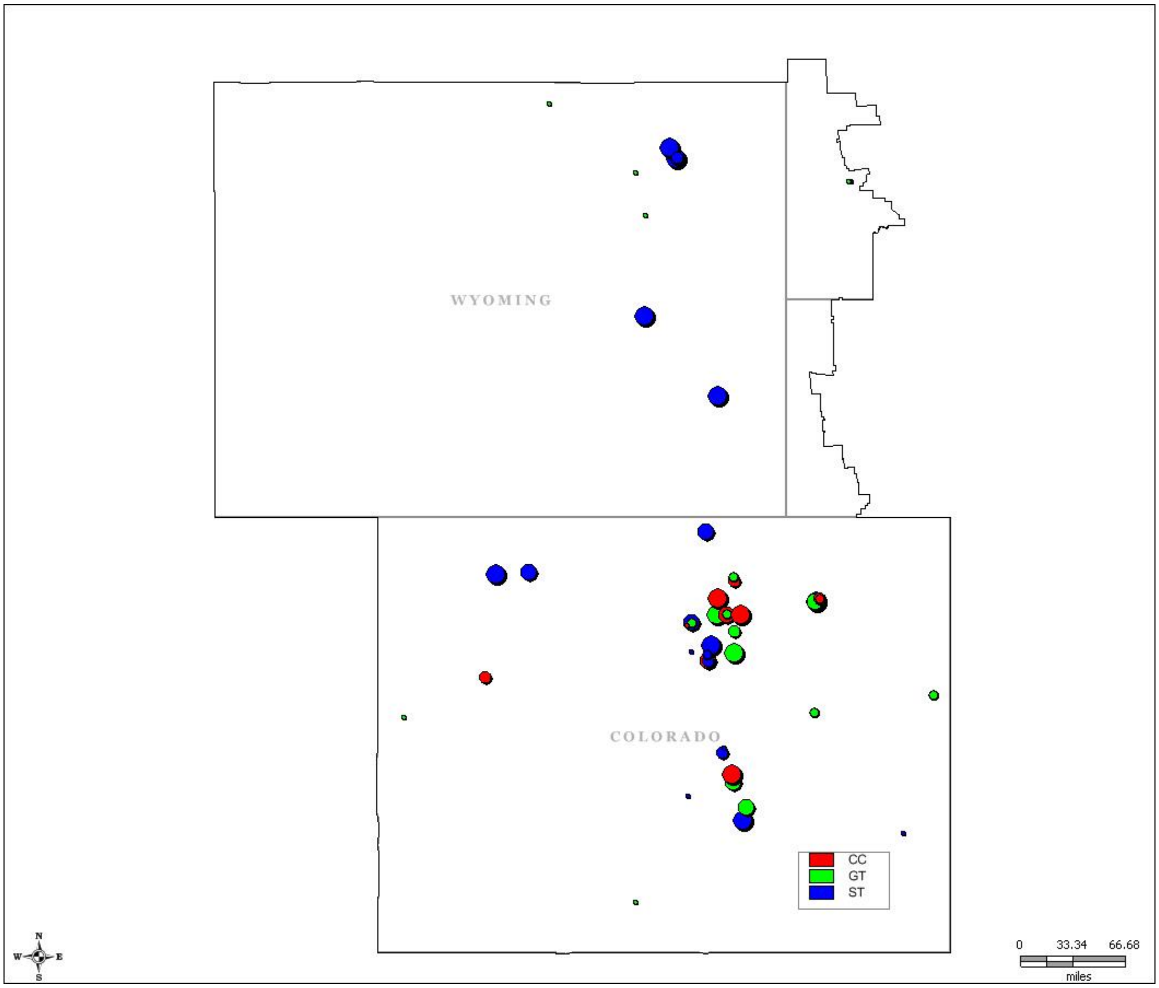

Figure 3. Thermal generators in the RMPP system

Load Assumptions

The peak load and energy totals for the RMPP region for the year 2020 are 13,661 MW and 80,000 GWh, respectively.

Generator Assumptions

The RMPP system consists of 10,383 MW of thermal power plants, 1,050 MW of hydro, and 560 MW of pumped storage power plants and nearly 168 MW of smaller power plants. Out of the 10,383 MW of thermal power plants, more than half are coal-fueled steam power plants. The breakdown of coal, gas-fueled simple and combined cycle plants is given in Figure 4. This system, which has a high installed base of coal plants, may not be representative of other parts of the WECC system. Therefore, a Modified-RMPP system where nearly 2,200 MW of coal plants were converted to combined cycle power plants was developed for this study. The breakdown of coal, gas-fueled simple and combined cycle plants for the Modified-RMPP system is given in Figure 5.

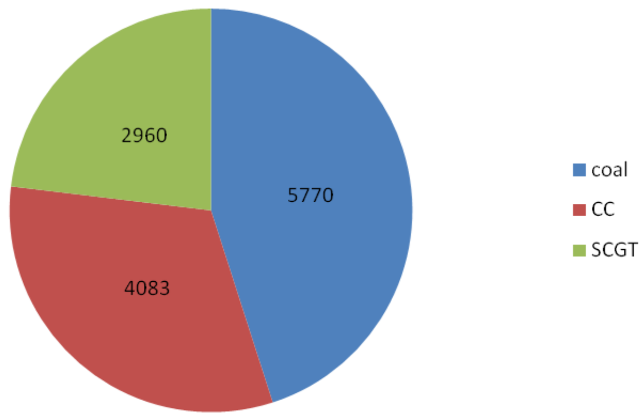

Figure 4. Thermal generation mix in the RMPP case

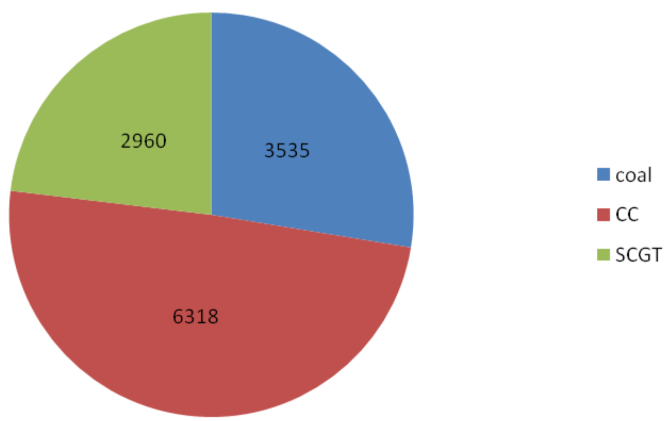

Figure 5. Thermal generation mix in the Modified-RMPP case

GT Technology

Since the available GT retrofits depend on the technology, a survey of the different GT technology (frame type) in WECC was conducted. GTs were classified as Aero, B, E, or F frame types, based on vintage and technology. Table 10 shows a few examples of GTs by make and model for each frame type.

Table 10. Frame Type, Make, and Model of GTs

Frame Type	Manufacturer Make and Model
Aero	GE LMS100, GE LM6000, GE LM 5000, P&W FT4
B	GE MS6001B
E	GE MS7001E, Siemens V84.2, Westinghouse W251
F	GE MS7001FA, Siemens V84.3, Westinghouse W501F
Other	GE MS5001, Westinghouse W191

In the RMPP system, there are approximately 4,000 MW of gas-fueled combined cycle plants, including 750 MW of generic expansion units added to maintain reserve margin. The mix of the various frame types for the RMPP system is shown in Figure 6. A large portion of the existing combined cycle capacity, including the new expansion units, is F frame. The coal units that were converted to combined cycle units in the Modified-RMPP system were also assumed to be F frame. In general, there are plenty of combined cycle units in the RMPP and Modified-RMPP system that are capable of being retrofitted for operational flexibility.[8]

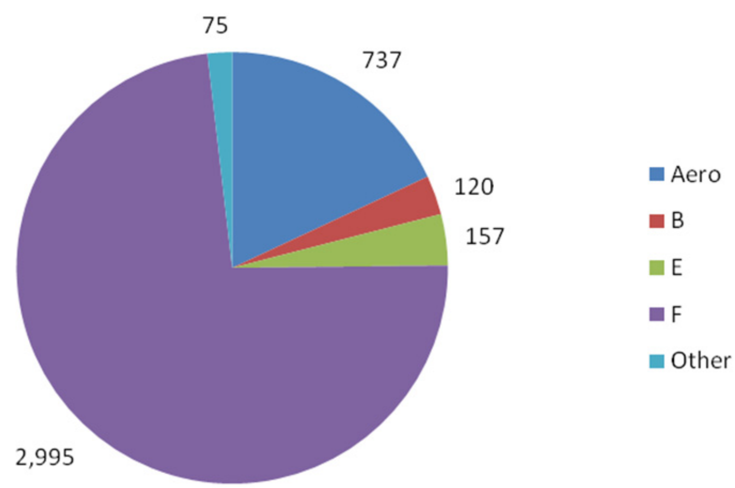

Figure 6. Combined cycle GT technology mix for the RMPP system

In the RMPP system, there are approximately 3,000 MW of gas-fueled simple cycle GT plants, including nearly 680 MW of generic expansion units added to maintain reserve margin. The mix of the various simple cycle GT frame types for the RMPP system is shown in Figure 7. A large portion of the existing simple cycle capacity, including the

[8] In reality, there may be other factors that determine whether a combined cycle plant can be retrofitted for operational flexibility. These include considerations such as the age of the unit and controls, condition of the unit, impact on the BOP, etc.

new expansion units, is made up of aero derivative GTs. There is also a significant installed capacity of F frame simple cycle GTs, as shown in the figure.

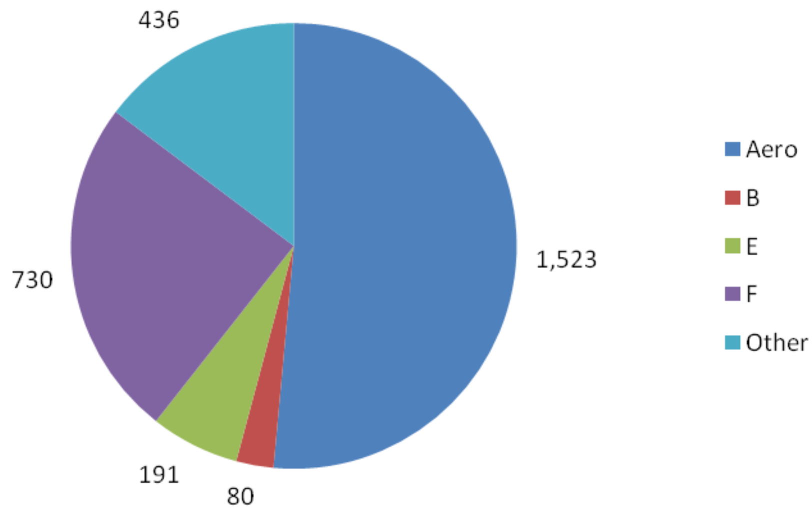

Figure 7. Simple cycle GT technology mix for the RMPP system

Steam Turbine Technology

Coal-fired generation technology can vary from one location to another. Boiler bottom and firing type / coal-fired power plants use one of five basic coal utilization processes:

- Stoker-fired
- Pulverized coal (PC)
- Cyclone-fired
- Fluidized-bed combustion (FBC)
- Coal gasification (IGCC).

To keep this analysis generic, we categorized the coal units based on size and steam pressure:

- Small Subcritical Coal (<300 MW)
- Large Subcritical Coal (>300 MW)
- Supercritical Coal.

Figure 8 shows the number of coal-fueled generation (some 39,000 MW) in the WECC systems. The mix of coal-fueled generation in the RMPP system is shown in Figure 9.

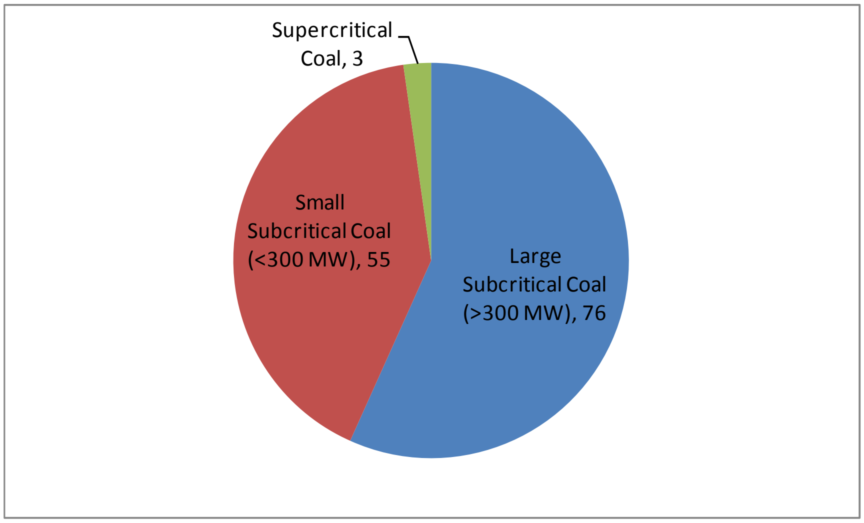

Figure 8. Coal-fired generation technology mix for the WECC system

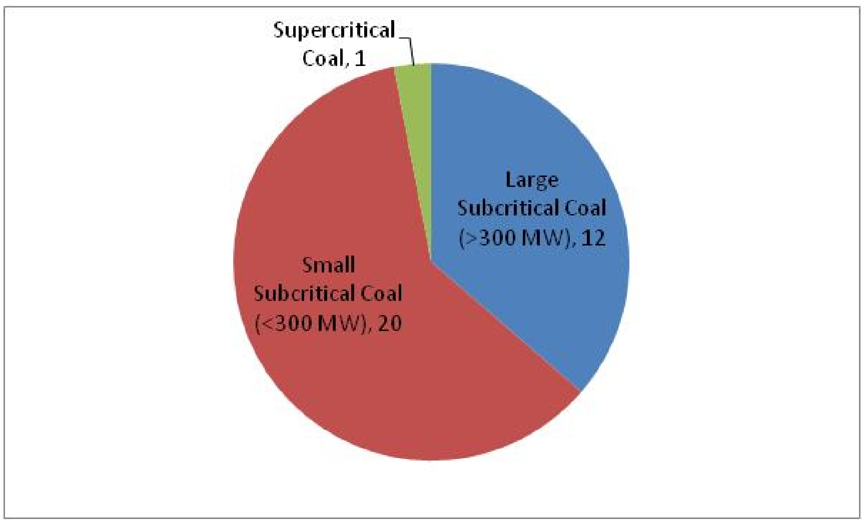

Figure 9. Coal-fired generation technology mix for the RMPP system

A comparison of both the RMPP and WECC systems in terms of percent capacity is shown in Figure 10. Evidently the systems are not very different in terms of MW capacity even though the number of units is different.

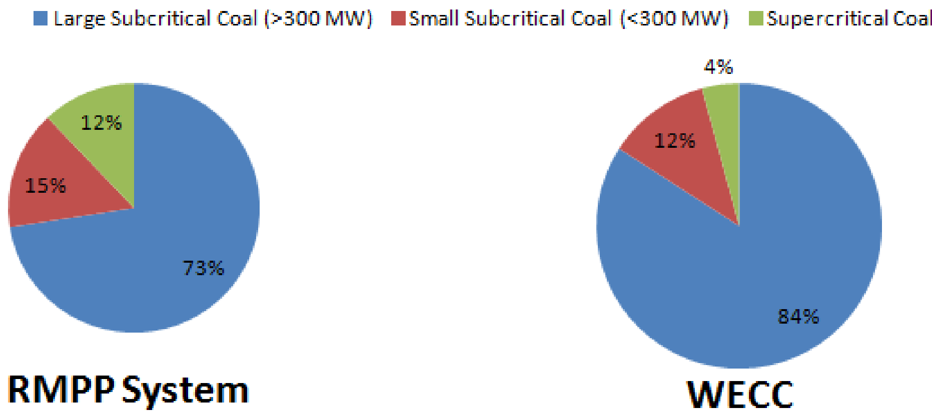

Figure 10. Coal-fired generation technology mix for the RMPP system

Renewable Generation Assumptions

This study was performed under four different renewable penetration assumptions for the RMPP and Modified-RMPP systems. The capacity and energy from wind and solar plants for each scenario is given in Table 11. The renewable energy penetrations in the four scenarios are 16%, 27%, 35% and 44%, respectively.

Table 11. Renewable Generation Assumptions

	Solar		Wind	
scenario	Cap (MW)	Energy(GWh)	Cap (MW)	Energy(GWh)
RE_101_Base	2,958	1,834	15,752	10,705
RE_103_Base	5,074	3,168	26,019	18,097
RE_105_Base	6,794	4,262	36,138	23,761
RE_109_Base	9,062	5,261	41,434	29,892

Fuel Price Assumptions

The fuel price assumptions are very important for this study since it determines which units (i.e., coal-fueled or gas-fueled) will be marginal, and which units will cycle. The annual average fuel price assumptions used in this study for the year 2020 are given below. There will be a slight difference in gas prices depending on the location of the power plant.

Coal: 1.42 $/MMBTU
Gas: 4.10 $/MMBTU
Oil: 21.87 $/MMBTU.

Cost-Benefit Analysis

This section discusses the results of the cost-benefit analysis of the flexibility retrofits. Section 6.1 discusses the methodology that was employed. Sections 6.2 and 6.3 discuss the results of the cost-benefit analysis for gas-fueled and coal-fueled power plants, respectively.

Methodology

The cost-benefit analysis was performed by running Plexos simulations with and without the retrofits on the selected power plants. From the two simulations, the changes in system-level production costs, as well as changes to the retrofitted power plants revenues (i.e., the benefits), were determined. The results were then analyzed under two scenarios. Under the first scenario, the study system was assumed to be a vertically integrated utility under a cost-based return structure. In this case, the system-level production cost savings due to the retrofits was compared against the additional revenue required to cover the capital (and operating costs, if any) associated with the retrofits. An FCR of 16% was used to convert the capital cost into annual revenue requirement. If the production cost savings were higher than the annual revenue requirements, the investment was deemed to have an economic merit.

Under the second scenario, the study system was treated as a deregulated market with merchant generation. The same results as those used in the regulated scenario were used in this analysis. However, in this case, for each generator that was retrofitted, the change in net revenue[9] was compared against the cost of capital associated with the retrofit. The NPV associated with the cash outflows (capital investment) and cash inflows (annual net revenue increase/decrease) for a 20-year period were calculated. If the NPV was positive, then the investment was deemed to have an economic merit.

The cost-benefit of the coal-fueled and gas-fueled power plants were studied separately in order to isolate their impacts. Although retrofits are available to improve turndown, ramp rate, and startup performance, the retrofits that primarily targeted turndown performance were studied since lower turndown capability was found to have the most beneficial impact on the system.

Additionally, since it's neither feasible nor economic to retrofit all units for lower turndown, only a subset of units (around 25% of the capacity) was targeted for the retrofitting. Sections 5.2.1 and 5.2.2 demonstrate that more than 25% of the gas- and coal-fueled power plants are capable of being retrofitted based on their technologies.

Gas-Fueled Power Plant Retrofits

The economic impact of retrofits installed on gas-fueled power plants was studied using the Modified-RMPP system. This system has approximately 6,300 MW of gas-fueled combined cycle plants and 3,000 MW of gas-fueled simple-cycle plants, as shown in

[9] It was assumed that the revenues from the energy market were the only source of revenue for the generation owner. No (increases in) capacity payments were assumed.

Figure 5. Figure 11 shows the cumulative energy, average number of starts, average number of ramps, and average hours at mingen for the combined cycle plants for the four renewable penetration cases. As renewable penetration increases, combined cycle plants go from intermediate load operation to cycling to finally being displaced. Case 2 (26.7% renewable penetration) was chosen for further analysis since it showed maximum cycling of combined cycle plants.

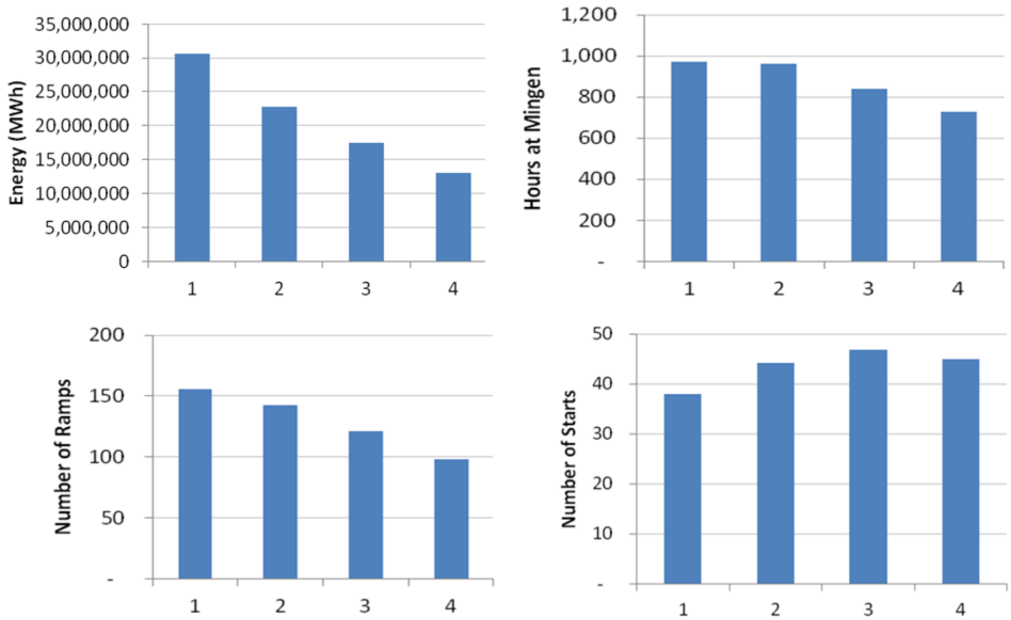

Figure 11. Operational impact on combined cycle plants for various renewable penetrations

About one-third of the combined cycle plant capacity (1,575 MW) was targeted for retrofitting. The best candidates for retrofitting are the units that produced most energy at their mingen levels in the Case 2 simulation. Using this criterion, three combined cycle power plants (3 out of 27) that totaled to 1,600 MW were chosen for retrofits. As shown in Section 5.2.1, the capacity of the combined cycle plants that are capable of being retrofitted far exceeds 1,600 MW.

Table 12 shows the system-level production cost of the Modified-RMPP system with and without the three plants retrofitted for lower turndown. This table shows that the savings in annual production cost is roughly $2M. Table 13, Table 14, and Table 15 show the annual energy, revenues, and variable costs for the three combined cycle plants with and without the retrofits. The regulation bid cost[10] is an additional cost to the system that seeks to capture the operational costs (variable O&M, decreased efficiency, etc.) of providing regulation reserves.

[10] For a further explanation of how this cost was calculated for the RMPP system refer to Hummon, et al. (2013), http://www.nrel.gov/docs/fy13osti/58491.pdf.

As observed in Table 12, the decrease in system-level production cost due to the retrofits is a little over $2M/year. The capital cost associated with the retrofits is $1.5M assuming the middle of the range cost estimate from Table 1. No additional operating costs are associated with these retrofits. Using an FCR of 16%, the annual revenue requirement associated with the investment of $1.5M is calculated to be $240,000.[11] This annual revenue requirement is well below the savings in annual production cost, indicating that the retrofits have a net-benefit to the system. Therefore, in a regulated, vertically-integrated utility environment, the investment in these retrofits does have some merit.

Table 12. Impact of Combined Cycle Retrofits on Production Cost

	Modified RMPP System - Case 2 (27% Penetration)	Modified RMPP System - Case 2 (27% Penetration) - with retrofits	Difference
Fuel Cost ($)	1,217,685,234	1,216,455,256	1,229,978
VO&M Cost ($)	116,978,206	116,706,891	271,316
Start & Shutdown Cost ($)	54,149,325	53,565,142	584,183
Regulation Bid Cost ($)	6,248,313	6,244,994	3,318
Total Generation Cost ($)	1,395,061,078	1,392,972,283	2,088,795

Table 13. Net Revenue Impact of Combined Cycle Retrofits for Unit A

UNIT A	Modified RMPP System - Case 2 (27% Penetration)	Modified RMPP System - Case 2 (27% Penetration) - with retrofits	Difference
Generation	1768351	1584755	(183,596)
Revenue	62,296,853	56,439,900	(5,856,953)
Fuel cost	53,621,511	46,939,490	(6,682,021)
Start & shutdown cost	766,638	653,062	(113,576)
VOM cost	5,322,738	4,770,113	(552,626)
Net Revenue	2,585,966	4,077,236	1,491,270

[11] Annual Revenue Requirement = FCR*Capital cost. The FCR is the rate that, when applied to the capital cost, gives the amount that is equal to the return on investment expected by shareholders, return of investment (depreciation), and taxes.

Table 14. Net Revenue Impact of Combined Cycle Retrofits for Unit B

UNIT B	Modified RMPP System - Case 2 (27% Penetration)	Modified RMPP System - Case 2 (27% Penetration) - with retrofits	Difference
Generation	2,728,741	2,697,415	(31,326)
Revenue	95,717,885	94,027,914	(1,689,971)
Fuel cost	86,545,750	85,819,230	(726,520)
Start & shutdown cost	1,998,486	1,903,320	(95,166)
VOM cost	3,001,615	2,967,157	(34,458)
Net Revenue	4,172,034	3,338,207	(833,827)

Table 15. Net Revenue Impact of Combined Cycle Retrofits for Unit C

UNIT C	Modified RMPP System - Case 2 (27% Penetration)	Modified RMPP System - Case 2 (27% Penetration) - with retrofits	Difference
Generation	3,090,459	3,182,496	92,037
Revenue	108,461,274	111,015,123	2,553,848
Fuel cost	100,387,668	103,463,892	3,076,224
Start & shutdown cost	5,091,912	5,021,191	(70,721)
VOM cost	3,399,504	3,500,746	101,242
Net Revenue	(417,810)	(970,707)	(552,897)

Most of the savings come from a decrease in fuel costs and startup and shutdown costs, as shown in Table 12. When the three combined cycle plants are retrofitted for lower turndown, they impact the operations of the remaining generators in the system. Table 16 shows the annual generation for coal, combined cycle, and simple cycle GT power plants with and without the retrofits on the three combined cycle plants. With the retrofits, the three combined cycle units are able to turndown lower, which in turn increases the generation from the remaining combined cycle, as well as coal power plants. The generation from simple cycle GTs decreases since combined cycle units remain online for more hours with the retrofits. Overall, this has an impact of lowering the fuel costs of the system, as shown in Table 12.

Table 16. Annual Generation With and Without Retrofits for Case 2, Modified-RMPP System

	Annual Generation (MWh)		
	Without Retrofits	With Retrofits	Delta
Coal	29,462,018	29,480,195	18,177
Combined Cycle GT	22,753,833	22,774,524	20,691
Simple Cycle GT	948,251	913,177	(35,075)

A portion of the savings in production cost is also attributable to the savings in startup and shutdown costs. Table 17 shows the cumulative combined cycle and simple cycle GT starts for the two cases. As observed from the table, there are fewer simple cycle GT starts with the retrofits.

Table 17. Impact of Combined Cycle Retrofits on Combined Cycle and GT Starts for Case 2, Modified-RMPP System

	Number of Starts		
	Without Retrofits	With Retrofits	Delta
Combined Cycle GT	1,300	1,288	12
Simple Cycle GT	7,084	6,824	260

Table 13, Table 14, and Table 15 show the annual energy, revenues, and variable costs for the three combined cycle plants (A, B, and C), with and without the retrofits. Figure 12 to Figure 14 show the dispatch of the combined cycle units with and without the turndown retrofit.

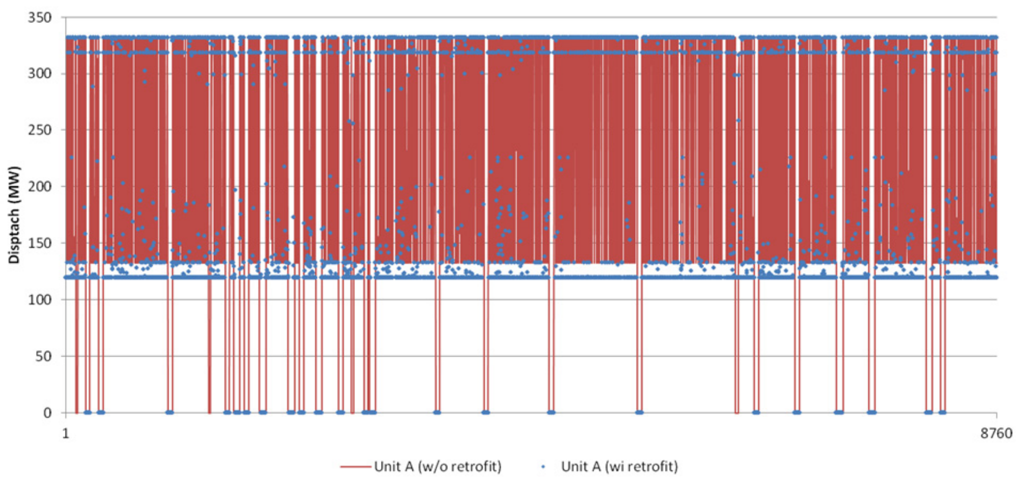

Figure 12. Dispatch of combined cycle Unit A, with and without turndown retrofit

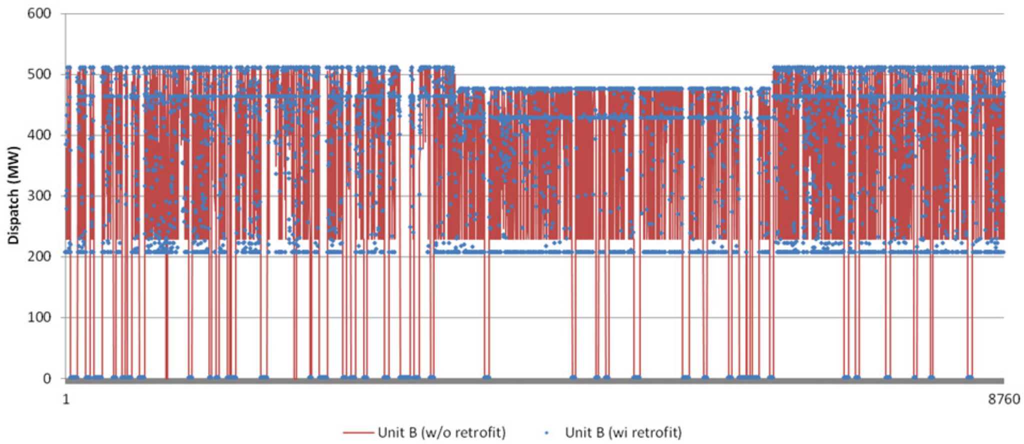

Figure 13. Dispatch of combined cycle Unit B, with and without turndown retrofit

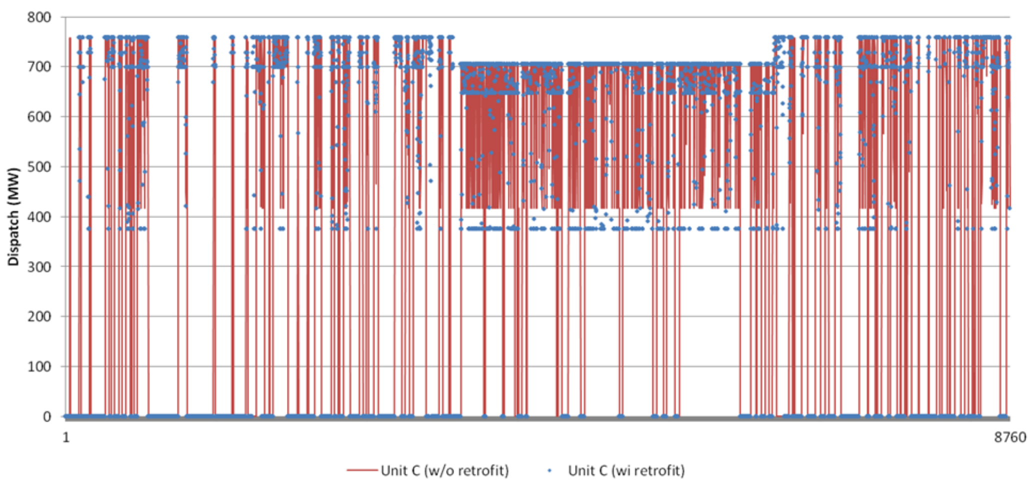

Figure 14. Dispatch of combined cycle Unit C with and without turndown retrofit

For combined cycle Unit A, the annual generation decreases with the addition of lower turndown capability. This is because Unit A is online during most hours with our without the turndown retrofit. With the retrofit, the unit operates at a lower dispatch level during off-peak hours. The fuel and VOM costs of operation decrease corresponding to the generation. However, the decrease in revenue is lower since the unit operates at a lower dispatch level during uneconomical hours. The net revenue is higher in the case with retrofits since the decrease in operating costs outweighs the decrease in revenues.

With an annual revenue increase of nearly \$1.5M, as shown in Table 13, the NPV (using a rate of 12%) of the investment of \$500,000 is nearly \$11,000,000 if the net revenue is assumed to increase at a constant 3% for 20 years. In a deregulated market environment, where generation owners make their investments based on returns, this investment does seem to have some merits.

For combined cycle Unit B, the annual generation decreases with the addition of lower turndown capability as observed for unit A. However, for this unit the net revenue decreases with the addition of retrofits. The decrease in revenue is more than the decrease in costs for this unit since the unit was in the money even during off-peak hours.

For combined cycle Unit C, the annual generation increases with the addition of lower turndown capability. This is because this unit cycled (starts and stops) frequently before the addition of the turndown retrofit (marginal unit). With the addition of the turndown retrofit, the unit stayed online more often, as shown in the figure (there are many instances when the blue dot (dispatch with retrofit) is above zero when the red line (dispatch without retrofit) is at zero). However, the increase in generation does not translate to an increase in net revenue because the additional generation comes from off-peak hours when the energy prices are lower.

From these examples it is clear that, while there may be a system-level benefit from a few units turning down deeper, there may or may not be a benefit at a unit-level. The next section discusses the turndown retrofits for coal-fueled power plants.

Coal-Fueled Power Plant Retrofits

The economic impact of retrofits installed on coal-fueled power plants was studied using the RMPP system. This system has approximately 5,700 MW of coal-fueled steam turbine power plants, as shown in Figure 4 in Section 5. Figure 15 shows the cumulative energy, average number of starts, average number of ramps, and average hours at mingen for the coal power plants for the four renewable penetration cases. To determine the cost-benefit of retrofitting coal units, the scenario with 44% renewable penetration (Case 4) was selected. This scenario entails a significant increase in the number of hours at mingen for the units.

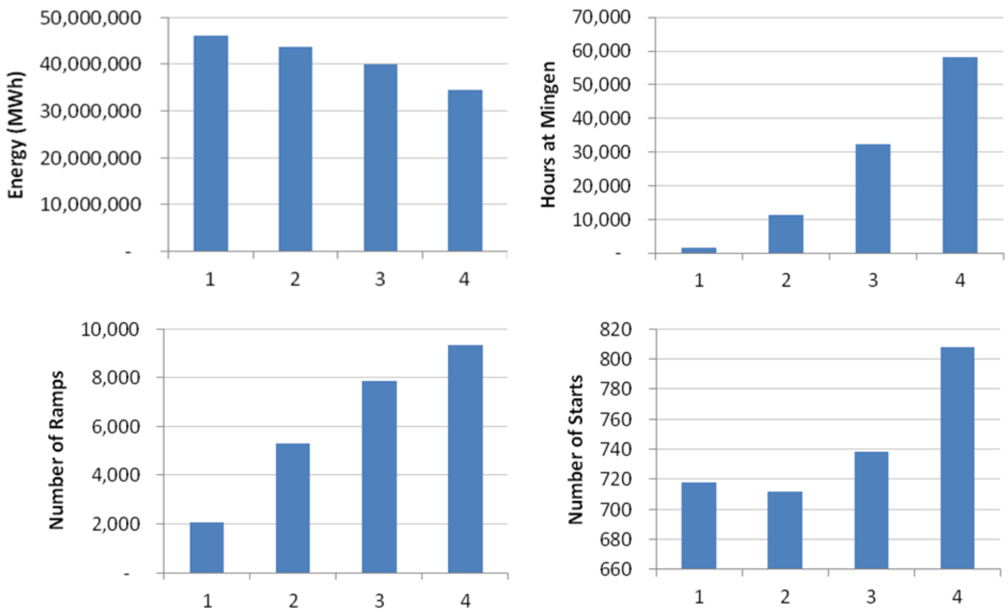

Figure 15. Operational impact on coal steam plants for various renewable penetrations

Figure 16 shows the number of hours at mingen for all the coal units in Case 4. The three units chosen for retrofits (units D, E, and F) are highlighted in red. Generally, larger units that have significant hours of mingen operation are good candidates for turndown retrofits; however, the location of the units on the grid is a driving force in determining the operations of the units.

Adequate consideration was given to the design and overall cost effectiveness of retrofits to coal units. For example, cost effective units with tilting burners-low and tangential firing were considered in this analysis. These units have dynamic control of steam generation through adjusting the position of the fireball within the boiler. Relatively new units are likely to have digital controls for faster ramping and cycling. A turbine bypass valve system is the most crucial technology, allowing for quicker run, down, and synchronization times. However, the back fit minimum cost estimate is almost $10-15M for this retrofit and may not be cost effective for every site.

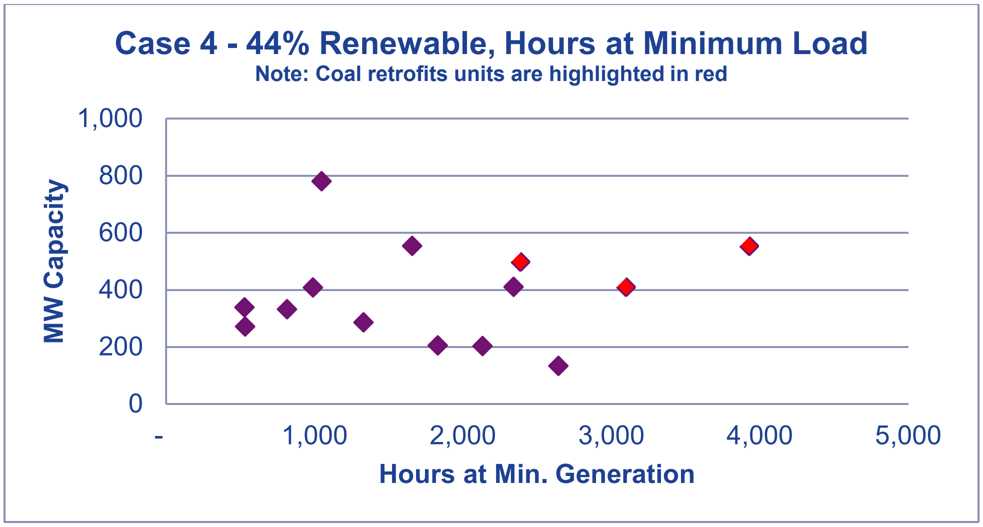

Figure 16. Coal steam plants, hours at mingen for Case 4

Note: Red dots represent the retrofit units.

Table 17 shows the production cost of the RMPP system with 44% renewable penetration, with and without three coal plants that were retrofitted for lower mingen. The three coal units represented about 24% of the RMPP coal capacity. This table shows that the savings in annual production cost is roughly $13M. Table 18, Table 19, and Table 20 show the annual energy, revenues, and variable costs for the three coal plants with and without the retrofits.

Table 17. Impact of Coal Retrofits on Production Cost

	RMPP System - Case 4 (44% Penetration)	RMPP System - Case 4 (44% Penetration) - with retrofits	Difference
Fuel Cost ($)	679,659,987	668,431,932	11,228,056
VO&M Cost ($)	106,289,366	105,653,808	635,559
Start & Shutdown Cost ($)	57,087,248	55,012,198	2,075,050
Regulation Bid Cost ($)	10,199,155	10,406,849	(207,694)
Total Generation Cost ($)	853,235,756	839,504,786	13,730,970

Table 18. Net Revenue Impact of Coal Plant Retrofits for Unit D

UNIT D	RMPP System - Case 4 (44% Penetration)	RMPP System - Case 4 (44% Penetration) - with retrofits	Difference
Generation	1,762,285	1,713,801	(48,483)
Revenue	71,845,868	59,095,988	(12,749,880)
Fuel cost	41,037,978	19,408,547	(21,629,431)
Start & shutdown cost	2,273,568	2,178,836	(94,732)
VOM cost	8,239,498	6,125,135	(2,114,363)
Net Revenue	20,294,825	31,383,471	11,088,646

Table 19. Net Revenue Impact of Coal Plant Retrofits for Unit E

UNIT E	RMPP System - Case 4 (44% Penetration)	RMPP System - Case 4 (44% Penetration) - with retrofits	Difference
Generation	2,737,375	2,034,928	(702,446)
Revenue	48,124,867	49,470,982	1,346,115
Fuel cost	29,303,798	28,360,530	(943,268)
Start & shutdown cost	1,894,644	1,543,784	(350,860)
VOM cost	5,304,477	5,158,542	(145,935)
Net Revenue	11,621,948	14,408,126	2,786,177

Table 20. Net Revenue Impact of Coal Plant Retrofits for Unit F

UNIT F	RMPP System - Case 4 (44% Penetration)	RMPP System - Case 4 (44% Penetration) - with retrofits	Difference
Generation	2,683,113	2,559,704	(123,410)
Revenue	70,079,947	70,580,248	500,302
Fuel cost	39,753,736	37,810,581	(1,943,155)
Start & shutdown cost	1,961,141	2,046,408	85,267
VOM cost	8,076,172	7,704,709	(371,463)
Net Revenue	20,288,899	23,018,551	2,729,652

As observed in Table 17, the decrease in system-level production cost due to the retrofits is approximately $13M/year. The capital cost associated with the retrofits is $9 M ($3M/unit). No additional operating costs are associated with these retrofits. Using an FCR of 16%, the annual revenue requirement associated with the investment of $9M is calculated to be $1.44M. This annual revenue requirement is well below the savings in annual production cost, indicating that the retrofits have a net-benefit to the system. Therefore, in a regulated, vertically-integrated utility environment, the investment in these retrofits does have some merit.

The savings in production cost come primarily from the savings in fuel costs. When the coal units are retrofitted for lower turndown, these units operate at lower dispatch levels, as shown in Figure 17 (for Coal Unit D), which allows the remaining coal and combined cycle plants to operate at a higher, more efficient dispatch. It also decreases the need for simple cycle GTs, and hence, the startup costs associated with their operation. Finally, the retrofits also result in less curtailment of renewable (primarily wind) generation, as shown in Table 21. However, the curtailment is not significant in either case. It decreases from 1.43% in the case without coal retrofits to 1.22% in the case with the retrofits.

Table 21. Annual Generation with and Without Retrofits for Case 4, RMPP System

	Annual Generation (MWh)		
	Without Retrofits	**With Retrofits**	**Delta**
Coal	34,588,108	34,343,870	(244,239)
Combined Cycle GT	4,236,303	4,434,668	198,365
Simple Cycle GT	598,703	563,308	(35,395)
Wind+Solar	13,459,718	13,485,862	26,144

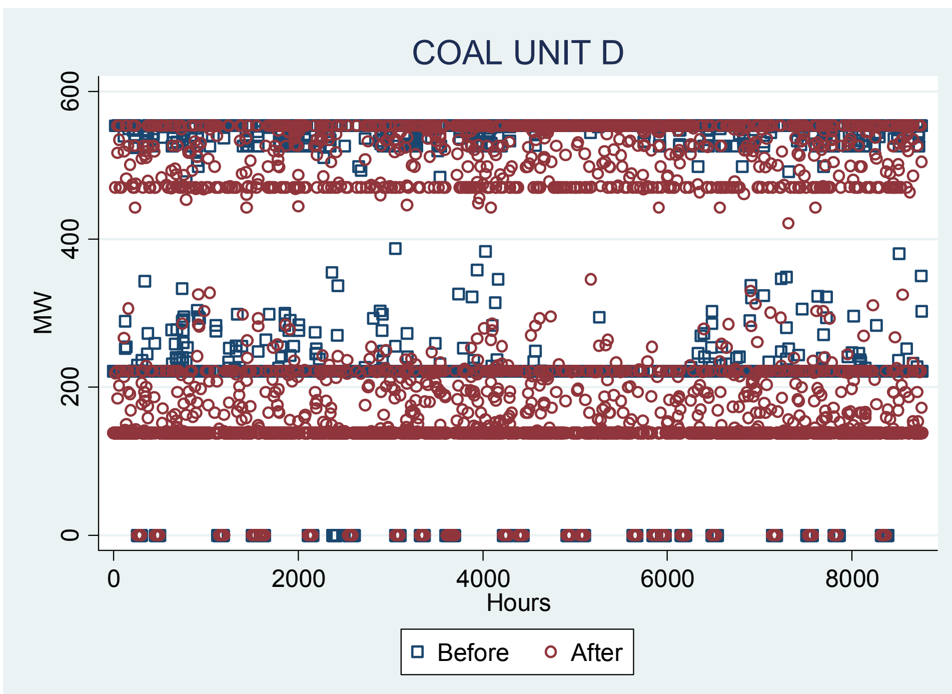

Figure 17. Mingen profile at Coal Unit D, before and after retrofit

Table 18, Table 19, and Table 20 show the annual energy, revenues, and variable costs for the three coal plants with and without the retrofits. Figure 18 through Figure show the same information found in the tables. As in the case of combined cycle units, all three retrofitted coal units produce less energy, as shown in the tables. However, unlike the combined cycle units, the net revenue increases for all three units with the retrofits.

This is because of the reduction in fuel costs[12] is much more significant when compared to the reduction in revenues. In fact, the revenues increase for Units E and F even with lower production. This is because the coals units are able to operate at a lower level during off-peak periods when they are not in the money. The off-peak prices are particularly low in this case, which has nearly 44% renewable penetration. Table 22 shows that the number of hours of operation at mingen for the three coal units is significantly higher after the units are retrofitted than before.

Table 22. Hours at Mingen Before and After Coal Retrofits

	Generation (MWh)			Hours @ Min. Gen
	Without Retrofit	With Retrofit	% Change	% Change (Before/After)
Coal-D	2,737,375	2,034,928	-26%	56%
Coal-E	1,762,285	1,713,801	-3%	59%
Coal-F	2,683,113	2,559,704	-5%	65%

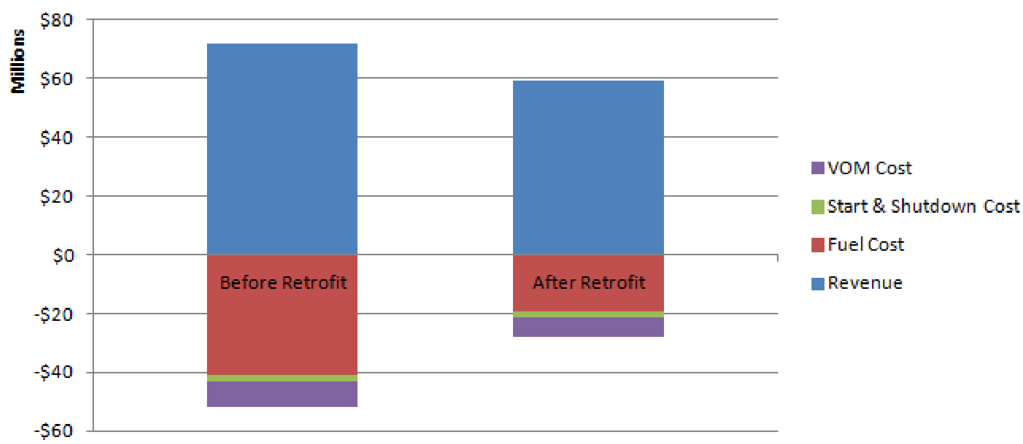

Figure 18. Coal Unit D, revenue and costs with and without retrofit

[12] The fuel costs in the tables do not account for the use of gas. However, we believe that with one mill operation and gas support, the total cost at the plants is a reasonable approximation at current natural gas price and the benefit from lower emissions.

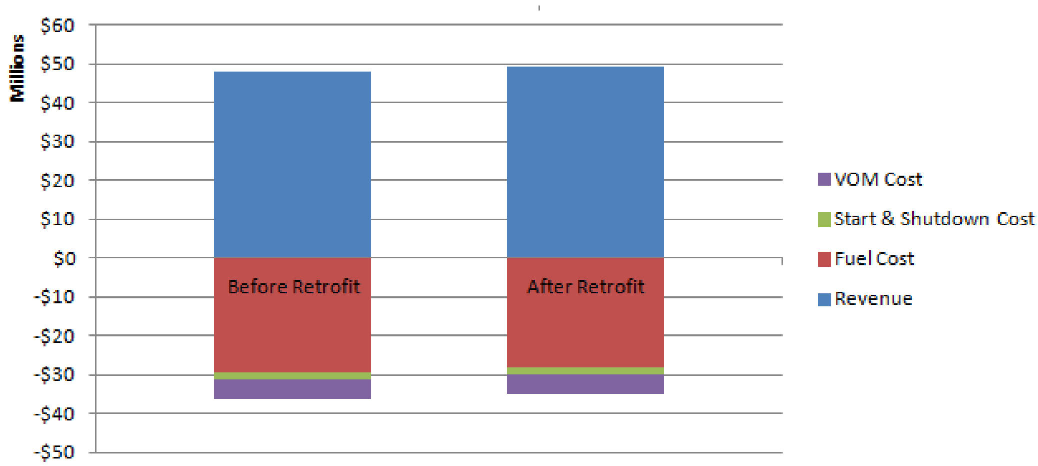

Figure 19. Coal Unit E, revenue and costs with and without retrofit

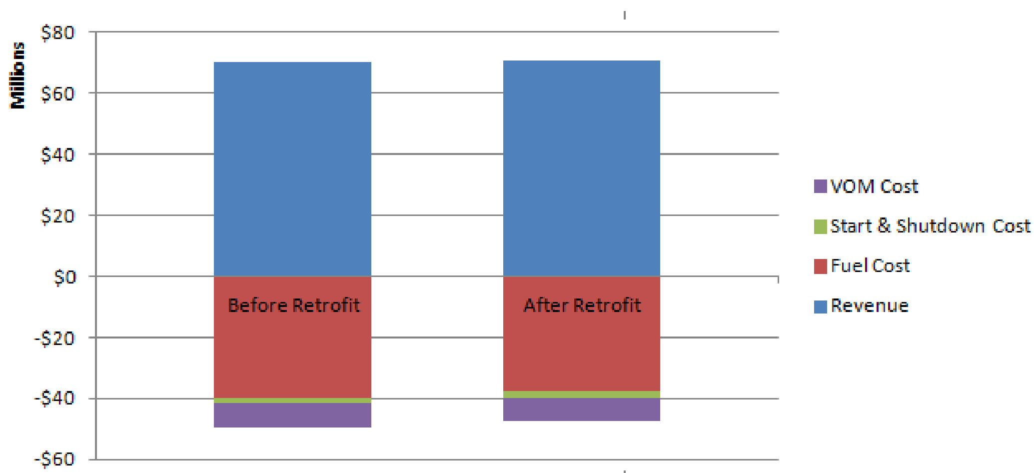

Figure 20. Coal Unit F, revenue and costs with and without retrofit

Conclusions

The research performed as a part of this study show that retrofits for improving operational flexibility are available for both gas-fueled simple and combined cycle power plants, as well as coal-fueled steam turbine power plants. Retrofitting some power plants for flexible operations will no doubt provide a benefit to the system. This work indicated that the benefits are commensurate with the costs of installing and operating retrofits.

Study results show that at a system level, retrofits that improve the turndown levels of gas-fueled and coal-fueled power plants have a net-benefit to the system. The system-level net-benefit was determined by comparing the system production cost savings with the capital and operating costs associated with the retrofits. It should be pointed out that operational flexibility retrofits may not always result in a net-benefit to the system. For example, operational flexibility retrofits for gas-fueled, gas turbine power plants may not be of much value in a coal-dominated system with low coal prices. Conversely, coal plant retrofits may not be of much value in a gas-dominated system with low gas prices.

The results also showed that while there might be system-level net-benefits, there may or may not be a benefit at plant level. The plant-level benefit for a power plant that is retrofitted is its potential increase in net revenues. The study results showed that in a gas-dominated system, only one out of the three retrofitted power plants showed an increase in net revenue after the installation of the retrofit. Plant-level revenue impacts are particularly important in deregulated regions where generators make their retrofit decisions based on the potential for increased profits. Policymakers need to explore mechanisms to incentivize plant owners to install retrofits that benefit the system.

While this exploratory study shows the value of operation flexibility retrofits to the system, especially under high renewable penetration conditions, additional work in the following areas are required:

- As a part of this study, an evaluation of power plants that could be retrofitted was performed based on the frame type for GT generators and pressure rating for coal units. There may be other factors that dictate whether a power plant is capable of being retrofitted for operational flexibility or not. Additional studies are required to determine what portion of the fleet could be retrofitted.
- This study determined that there is value in retrofitting both gas-fueled and coal-fueled power plants for lower turndown capability. Further work is required to determine the value of faster ramp rates and faster and less expensive starts to the system.
- This study analyzed the impact of retrofitting approximately 25% of the gas-fueled and coal-fueled generating capacity. Further analysis is required to determine the optimal level of flexible capability in the system.
- This study focused on operational flexibility available primarily through GT controls. In a combined cycle application, further improvements can be made to the HRSG and steam turbine to make the plant more flexible. While information

on some of these retrofits was gathered, they were not examined as a part of this study. Future study of these retrofits is recommended.

- This study analyzed the impacts of operational flexibility under a set of fuel price assumptions. Any change in fuel prices, particularly lower gas prices, may increase the value of operational flexibility retrofits for GT generators. Future studies should analyze the impact of retrofits under multiple fuel price scenarios to increase the robustness of the conclusions.
- Finally, this study focused on the costs versus benefits of emission retrofits. While these retrofits are designed for emissions compliance, further analysis of the emissions impact of retrofits for gas-fueled and coal-fueled power plants is recommended.

Appendix A. GE Operational Flexibility Solutions

The solutions included in the series of GE OpFlex packages improve the ability for GT/CC facilities to:

- Deliver power quickly in response to changing grid demands
- Overcome equipment limitations that prevent power plants from capitalizing on emerging market opportunities
- Eliminate slow, inefficient startups and their associated costs
- Stay online more cost effectively
- Meet more demand within existing markets
- Generate revenue through ancillary markets
- Reduce emissions "events" and potentially costly compliance penalties that can result
- Expand the operating window of a power plant.

GE OpFlex Startup Agility Solutions

OpFlex Startup Agility Solutions enable fast, reliable and repeatable startup profiles. Specifically, the underlying applications target reductions in startup time and corresponding startup variability along with reduced emissions and reduced fuel consumption. Solutions in the suite include:

GT

- Fast-start: employs a "purge credit" system which moves the startup purge to the prior shutdown, plus faster acceleration and loading rates to achieve near baseload output in 10 minutes. This enables participation in Non-Spinning Reserve Ancillary Services markets.
- Startup Fuel Heating: relaxes fuel temperature permissives that can cause holds in loading, enabling higher loads to be achieved in shorter times, and reducing time spent in inefficient, high emissions operating modes.
- Startup NOx: introduces a new combustion mode which reduces visible "yellow plume" and total NOx emissions during the startup sequence.

Steam Turbine

- Steam Turbine Agility: automates steam turbine startups using best-in-class sequencing and model-based control to enable faster and more consistent, repeatable steam turbine startups in order to achieve the best balance between rotor life consumption and startup speed. Faster steam turbine startups result in less GT operation at low loads in inefficient, high emissions operating modes.

HRSG

- Advanced SCR Ammonia Control: utilizes feedback models to enable SCR operation at lower exhaust temperatures while ensuring minimal ammonia slip, thus significantly reducing NOx emissions during startup.
- Advanced HRSG Attemperator Control: uses feed forward control loops to proactively adjust HRSG attemperator flows during GT startup and load changes, thus reducing CC plant instability and trip risk. Combined cycle starts are faster and more consistent, system reliability is improved, and the plant can be confidently operated at higher steam temperatures--closer to entitlement--to enable increased plant efficiency and output.

GE OpFlex Combustor Operability Solutions

OpFlex Combustor Operability Solutions employ advanced technologies to enable robust turbine operation during weather, fuel, and grid frequency variations to improve fuel flexibility, avoid trips, and extend operating intervals.

The applications which are included in this suite are:

Grid Stability

- Enhanced Transient Stability: employs multiple technologies on a Model-Based Control (MBC) software platform to improve robustness to grid frequency transients and meet future grid code requirements to ensure a stable power grid. Modern sensor fault detection, isolation, and accommodation (FDIA) schemes enable continued operation in conditions where traditional control would have results in a trip, thus improving overall availability and reliability.

Automated DLN Tuning

- Ambient Select: provides basic automated DLN tuning capability through enabling the turbine to automatically choose from among several pre-programmed tuning fuel split schedules based on ambient temperature, reducing the need for seasonal tuning for emissions compliance.
- AutoTune LT: provides advanced automated DLN tuning capability through continuous fuel split schedule biasing as ambient conditions change and as turbine hardware and performance degrades over time, reducing the need for tuning at any time for emissions compliance.
- AutoTune DX: provides GE's most robust automated DLN combustor tuning solution by combining MBC technology and detailed, field validated combustion models with combustion dynamics feedback. Combustor health is monitored and tuned continuously, enabling increased gas fuel composition flexibility, avoidance of seasonal tuning for emissions compliance, and expanded capability to handle, large rapid transients.

GE OpFlex Load Flexibility Solutions

OpFlex Load Flexibility Solutions focus on offerings to enable emissions-compliant load range expansion, efficiency, responsiveness, and customization. Solutions enable higher full load and peak load output, deeper turndown, and improved efficiency. The applications included in this suite are:

Output

- Variable Airflow: utilizes advanced combustor fuel scheduling to enable flexible operation at higher maximum IGV settings to provide increased output while maintaining emissions compliance, or at lower settings to provide improved combined cycle efficiency.
- Variable Peak Fire: provides the capability to variably overfire the GT for increased output when economic conditions justify the increased maintenance cost and increased emissions. This option includes functionality to increase output as much as possible while automatically maintaining emissions compliance.
- Cold-Day Performance: leverages OpFlex AutoTune DX to improve combustor operability in cold weather, thus allowing higher firing temperatures and significantly higher output in cold conditions while maintaining emissions compliance.

Responsiveness

- Fast Ramp: enables load ramping at up to twice the normal rate, such that the full minimum- load-to-baseload range can be covered in less than five minutes, enabling increased participation in regulating reserve markets.
- Grid Code Package: provides multiple custom software packages to ensure compliance with country-specific grid codes worldwide.

Turndown

- Extended Turndown: extends low emissions operation to lower load levels, enabling reduced fuel consumption at minimum loads and improving the economics to remain online overnight and avoid shutdown and startup costs. This also extends the available load range for operation, improving dispatch flexibility and enabling greater participation in regulating reserve markets.

Efficiency

- Variable Inlet Bleed Heat: replaces conservative anti-icing protection logic with a model-based control approach to reduce inefficient Inlet Bleed Heat use, particularly in warm weather, to provide significant improvements in part load efficiency.

GE OpFlex System Reliability Solutions

OpFlex System Reliability Solutions are a suite of enhancements focused on better enabling reliable, cost effective operation by reducing system trips, improving the recovery process, and reducing downtime. Solutions include:

Fuels Reliability

- HFO Availability Package: utilizes a rapid cooldown, automated turbine wash cycle, and MBC to improve availability of turbines burning heavy fuel oil (HFO), which are subject to rapid performance degradation.
- Liquid Fuel Operability Package: provides a collection of control software enhancements that help improve operation on liquid fuels, and in particular, ensure successful transfers between liquid and gas fuels and vice versa.

System Reliability

- AutoRecover: enables B/E-class DLN1 combustors to quickly and automatically return to low emissions premix operation following external transients which can cause the combustor to enter high emissions, high maintenance factor operation
- Reliability Software Package: provides a collection of control software and sensor enhancements that help improve overall turbine operational reliability, leveraging the latest fleet experience and new unit design standards.

Diagnostics/Productivity

- System Diagnostics Package: provides a collection of control software enhancements that improve operator capability to more quickly and efficiently diagnose system issues, restore operation, and reduce overall downtime.
- Startup Productivity Package: provides a collection of control software enhancements that help improve the overall startup process to ensure on-time, reliable plant startup capability.
- Operational Productivity Package: provides a collection of control software enhancements that help improve operator productivity when executing various systems tests and procedures, particularly those not performed very frequently.

Summary

The respective improvements in the key performance and flexibility attributes that can be obtained with these packages can be substantial. Some examples of the potential improvements to the GT capabilities are:

- Output: Approximately +3-5%
- Heat Rate: Approximately -0.2 to -0.4%
- Turndown Load Level: Additional 5-10% load reduction (in emissions compliance)
- Startup Emissions: ~50-70% reductions in NOx, CO, and CO2
- Startup Fuel Consumption: ~70% heat consumption improvement
- Startup Time: More than 50-60% reduction in startup time
- Availability & Reliability: ~0.4% and ~0.2% respectively
- Ramp Rate: As much as a 100% improvement on a MW/min basis

Appendix B. Additional Information on Coal Retrofits

Retrofit	Description (What is the retrofit?)
Improved and automated boiler drains	Implementation of advanced sensors and controls to automate drains.
Steam flow redistribution and metallurgy improvements in SH/RH	Reduce local variations in superheater/reheater temperature by changing steam flow patterns and improve corrosion resistance/strength with different materials.
Steam coil air heater to pre warm boiler and air heater	Recover waste steam heat by condensing steam to warm boiler components. Also, condensing steam may be used in an air preheater (APH) to warm air prior to the regenerative air heater.
Gas bypass to keep air heater warm	Bleed gas from GT to warm air heater components.
Improved APH basket life when cycling in or through the wet flue gas temperature region by installing traveling APH blowers to remove deposits prior to cycling down in load	As the air preheater (APH) cools, flue gas may reach the acid dew point. By using a blower(s) to remove deposits from the external surface of APH prior to cooling, the amount of condensed acid is minimized.
Improved APH basket life with improved materials when cycling in or through the wet flue gas temperature region	Upgrade APH materials which pass through the acid dew point transition temperature to improve corrosion resistance.
Improved selected expansion joints. This is not a complete replacement of all expansion joints.	Maintain system pressure and/or reduce pressure drop by replacing selected critical and/or degraded expansion joints.
Add steam cooled enclosure min flow protection for balanced flow with blow down or dump to LP turbine	During blow down or (high-pressure) turbine bypass operations, ensure steam flow by adding a heat transfer surface (or verifying sufficient area) to generate saturated steam.
Improved flame proving equipment for burners	Upgrade flame proving equipment to verify the igniter is releasing adequate ignition energy over the desired area, which ensures complete combustion.
Low load gas igniters to allow min generation on gas fuel only	Install new igniters to allow low load operation on gas fuel only.
Dual Fuel burners – use NG over coal (Add NG to all burners). Gas supply is not included	Install new burners to allow low load operation on gas fuel only and to ensure complete combustion of coal at higher loads.
New feeders with gravimetric type feeder with improved weighing of coal feed to mill	Improve control of fuel mass flow rate by installing or converting to a gravimetric feeder.
Automatic pressure control on roll and race to adjust the grinding pressure of the coal mill.	Implement automatic grinding pressure adjustment in response to fuel grindability and desired degree of pulverization, which helps ensure complete fuel combustion.

Heated precipitator hoppers	Reduce clogging in fly ash collection hoppers due to flue gas condensation and/or freezing, especially within hopper throat.
New dry fly ash transport	Install new system to extract fly ash from stack gases and sequester them for disposal and/or recycling.
Small package boiler, electric boiler with air modeling and permit	Provide auxiliary/process steam while plant is shut down by using an electric boiler drawing from hotel or offsite power sources.
Motor driven boiler feed pump with startup to min load capability	Allow cold startup by enabling feed water flow without the use of process/auxiliary boiler steam required for a turbine-driven feed water pump. The motor-driven boiler feed pump shuts down once load increases above minimal levels.
Improved vibration sensing and monitoring of all rotating equipment	Install vibration sensors and recording equipment to continuously monitor rotating equipment.
Speed Controlled motors on ID and FD fans using variable frequency drives	Use motor speed rather than inlet vanes/dampers to regulate air flow from forced draft (FD) and induced draft (ID) air supply fans.
Transformer monitoring gas analysis and temperature and emergency oil removal if arcing occurs	Install transformer monitoring and automated drain system. Oil is drained to minimize fire hazard in the event of a transformer fault.
Turbine electric heating blankets	Maintain turbine temperature to facilitate cycling operations and warm re-starts.
Convert 3 rpm to 40 rpm turning gear motor to prevent blade attachment wear and generator loose parts	Increase turbine rotation speed while unloaded to maintain rotor balance. This helps prolong rotor life and prevents premature sagging of attached parts.
New valve operators Full arc admission/sliding pressure	Install new main steam control/governor valves to allow equal amounts of steam along the full circumference of the turbine (“full arc” admission). Sliding pressure operation facilitates partial load operation by varying steam pressure to the turbine.
Turbine drains to the condenser hot well including main steam drains and before seat warmup drains should be routed to the hotwell with a sparger discharge below the normal water level.	Reroute drains so that sparger discharge is below condenser water level, which facilitates condensation and reduces condenser component wear, as the discharge is buffered by liquid rather than discharging directly onto tubes and structures.
Turbine water Induction prevention Upgrades including MOVs on extractions and inspection of heater drains and extraction piping and bellows in condenser	Reduce steam turbine damage due to ingestion of water. Deploy motor-operated valves (MOVs) on and conduct inspections of drain and extraction lines to identify potential sources of liquid water which may be entrained in steam flow.
Condenser tube shielding	Provide physical shielding so that steam turbine exhaust does not impinge directly on condenser tubes. This will reduce condenser tube wear.
Nitrogen Blanketing of condensate storage tank, Boiler, turbine	Place inert gas blanket in certain components to reduce corrosion.

Condensate polishing system for rapid water chemistry cleanup when cycling	Provide mechanical and ion exchange filters to clean up condensate while plant is on-line. Size adequately to allow operation under varying loads.
Larger condensate storage tanks	Install appropriately-sized condensate storage tanks to allow for increased storage of condensate when operating under low load conditions.