ELECTRIC POWER RESEARCH INSTITUTE

Unit Ramp Rate Optimization Guidelines

Methodology and Technical Approach

2018 TECHNICAL REPORT

Unit Ramp Rate Optimization Guidelines

Methodology and Technical Approach (Supersedes 3002011175)

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ABSTRACT

Improving the operational flexibility of fossil fuel generating units is increasingly important to support the evolution of the bulk power system. Updating plant operations and controls to provide more dynamic response to load changes consistent with the capabilities of installed equipment and systems is an important element of this effort. This report presents a methodology for understanding and improving unit ramp rate operations and controls. The methodology uses both engineering reviews and operational testing to diagnose the limits on unit ramp rate and optimize the response to load changes. Guidance is included to support understanding and improving the existing unit control logic. Example documentation to implement the steps of the ramp rate improvement methodology is also provided. The methodology presented can be implemented on any type of fossil fuel generating unit technology. Case studies are provided from two pilot implementations of the ramp rate improvement methodology; a coal-fired supercritical generating unit and a natural gas-fired combined cycle unit.

Keywords

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PRIMARY AUDIENCE: Plant engineers at fossil fuel generating power plants

SECONDARY AUDIENCE: Corporate technical services engineers

KEY RESEARCH QUESTION

An evolution in the operation of the bulk power system has occurred due to the expanding contribution of renewable generation to the power supply. Fossil fuel generating units that once operated in a base load manner are following system load demand over larger ranges and ramp between loads more frequently. In most cases, fossil fuel generating units were designed for base load operation, and current operators have limited experience to inform their understanding of the possibilities to improve the ramp rate of these units. A methodology for ramp rate optimization will assist generating unit operators in improving their plants' ramping ability.

RESEARCH OVERVIEW

The main objective of the project was to develop a methodology for evaluating and improving unit ramp rate at any fossil fuel generating unit, with sufficient guidance to facilitate implementation by power plant personnel. The research involved reviewing industry experience with unit ramp rate improvement and methods for improving unit control logic. Pilot implementations were performed at two generating units, providing demonstrations of the ramp rate optimization methodology through the diagnosis testing step. The pilot tests also provided the basis for case studies of the specific improvements necessary to increase the ramp rate of (1) a coal-fired supercritical boiler, and (2) a natural gas-fired combined cycle plant. The case study presentations include recommendations for implementing the improvements identified during the diagnosis testing in accordance with the remaining steps of the ramp rate optimization methodology.

KEY FINDINGS

The findings from the development and implementation of the ramp rate optimization methodology were:

- Comprehensive understanding of the unit control logic is vital to diagnosing the limits to the unit ramp rate. The evolutionary nature of the unit control logic makes ramp rate testing a vital tool in developing the necessary changes to increase unit ramp rate.
- Manual operation of specific systems and components will be required during the diagnosis testing to increase the unit ramp rate. Bypassing selected automatic controls is necessary to identifying the control logic responsible for limiting unit ramp rate. Additional operating staff should be provided during the ramp rate diagnosis testing to support the need for expanded manual operation of the unit.
- Acknowledgement and consideration of personnel biases will be required to successfully examine the technical limits on unit ramp rate. Developing an understanding of the value of increased unit ramp rate is important in influencing personnel.
- Evaluation time is required between ramp rate diagnosis test runs to develop a complete identification of the step(s) necessary to address roadblocks. More than one area of the unit operation or control may be simultaneously limiting unit ramp rate.

The specific findings from the case study of ramp rate diagnosis of a coal-fired supercritical steam generating unit were:

- During the abbreviated diagnosis testing completed, the original unit ramp rate was doubled (to 6 MW/min).
- Changes in the initial conditions prior to load changes were important to the improving the ramp rate. These included: minimizing the superheat spray flow at the beginning of the load ramp, increasing the bias on the excess O_2 trim, firing using the upper mill elevations, and suspending furnace sootblowing at low load.
- Permanent implementation of the increased unit ramp rate will require changes to a number of control loops including updating the mill controls to provide balanced heat input and to minimize heat input spikes, revising the superheater control settings to improve steady state temperature control and increasing the response rate on a number of control loops, including the ramp rate feedback control loop.
- Implementation of the control modifications should be performed as individual steps, with provision for additional testing to demonstrate the stability and suitability of each change, prior to implementing the next change.

The specific findings from the case study of ramp rate diagnosis of a 2×1 natural gas-fired combined cycle generating unit were:

- The balance of plant BOP controls are an important bottleneck to the combined cycle unit ramp rate. The combustion turbines' ramp rates are limited by the BOP controls' communication of ramp rate limits from the steam turbine. In addition, the nature the of load change signal pulses transmitted to the combustion turbines resulted in ramping at less-than-optimal rates.
- During the diagnosis testing, modifications to the balance of plant controls system settings demonstrated combined cycle unit ramp rates of +30 MW/min, more than double the normal plant ramp rate. Performance of the host unit during testing, and information on other similarly-designed plants, suggests much higher ramp rates may be possible (i.e., > 40 MW/min).
- The host unit's combustion turbine compressor have a flat slot bottom design that is subject to cracking. The cracks initiate through startup/shutdown cycles. Once initiated, the cracks are propagated by combustion turbine load swings. Implementation of any ramp rate changes at the host unit must consider the current material condition of the combustion turbine compressor rotors.

WHY THIS MATTERS

Competitive pressures are differentiating electric generating units based on their ability to quickly change load. The methodology presented in this report provides a pathway to improve the competitiveness of fossil fuel generating units that can no longer operate as base load generation.

HOW TO APPLY RESULTS

The optimization methodology developed by this research could be applied to any fossil fuel generating power plant to address competitive pressures to provide enhanced ramp rate. The methodology provides for defining, evaluating, and implementing an improved unit ramp rate.

Specific findings concerning roadblocks to improved ramping operation at (1) a coal-fired supercritical steam generating unit and (2) a natural gas-fired combined cycle generating unit are provided in the case studies completed as part of this research. Additional case studies will be added in subsequent revisions of this report to expand the experience with ramp rate improvement at other types of fossil fuel generating units.

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1 INTRODUCTION

Purpose

This report describes a methodology for optimizing the ramp rate at fossil fuel generating units as load is increased or decreased between minimum and full load. The focus of the methodology is on modifying the control of the unit during load ramps through changes in control logic, operating procedures, and instrumentation. Changes in control equipment capabilities, to expand their response range or speed of operation, are less critical to increasing the unit ramp rate but may also be identified. The methodology presented in this report is intended to effectively expand the capability of fossil fuel generating units to meet the demands of an evolving energy market, without sacrificing safety and reliability.

The methodology provides a systematic approach to identify specific changes to increase the unit ramp rate. Technical guidance on implementing the methodology is provided, as well as approaches to address the key improvements in the fossil fuel generating unit operation.

Pilot implementations of the unit ramp rate optimization methodology were performed to prototype the methodology details at (1) a once-through supercritical coal-fired power station, and (2) a 2×1 natural gas-fired combined cycle plant. These pilot implementations also serve as ramp rate improvement diagnosis case studies for these fossil fuel generating technologies.

Background

An evolution in the operation of electrical distribution systems has occurred driven by the expanding contribution of renewable generation to the power supply. Renewable portfolio standards promulgated in many states are steadily expanding the generation share associated with renewable generation. The variability of renewable generation, as provided by solar and wind sources, has imposed the need for additional responsiveness from fossil fuel generation to support distribution system stability. Competitive pressures are differentiating units based on their responsiveness in addition to their generation cost.

One aspect of unit responsiveness is the unit ramp rate, specifically the rate of unit load increase from minimum load to full load. Fossil fuel generating units once dispatched as base load are following system load demand over larger ranges and ramp between loads more frequently. These changes promote interest in understanding and improving unit ramp rate.

Dynamic operation of fossil fuel generating units requires the coordination of a number of systems, equipment, and controls. Accurate and timely measurement of unit operating parameters under these transient conditions is often a challenge for the installed instrumentation.

Control systems, often tuned for stability and not responsiveness to changing operations, may rely on operator action to navigate the changes required. The more rapid the rate of change, the greater the challenge to avoid upsets in the processes for converting the stored chemical energy in the fuel into electrical energy.

The methodology presented in this report accounts for potentially defining more than one ramp rate over the unit load range. As illustrated in Figure 1-1, the potential for three different unit ramp rates between minimum and full unit loads can be considered:

- Initial Ramp Rate – rate of load change limited by initial change from unit operating configuration required to achieve stable minimum load operation.
- Nominal Ramp Rate – rate of load change applied during the majority of the increase in unit load.
- Approach Ramp Rate – rate of load change limited by achieving stable unit operation under full load conditions.

In this methodology, it is expected that both minimum and full loads are stable conditions for continuous operation of the unit.

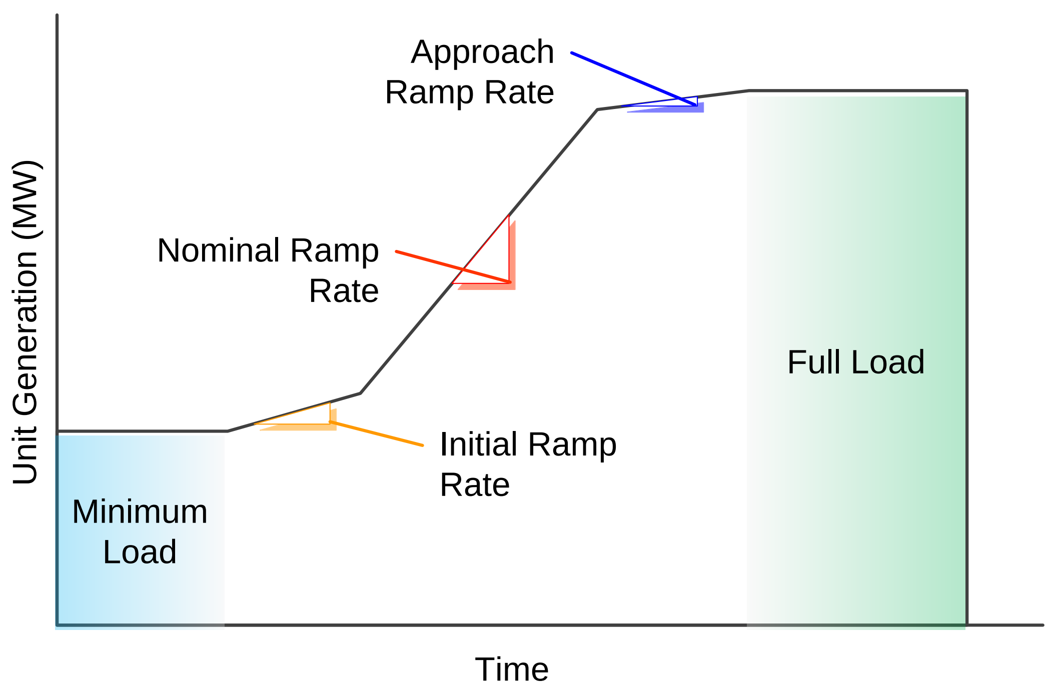


Figure 1-1
Unit ramp rate regimes

The ramp rate behavior of the unit to support unit start-up and increasing load to maximum emergency generation are not addressed in this methodology. These regions of unit operation involve additional concerns beyond the scope of this report.

Existing unit ramp rates were determined when there was limited value from ramping operations. The values implemented by the unit controls vendors were based on conservative recommendations from the principal equipment vendors and designed for limited load changes as part of normal unit operation. Power plant operators are now recognizing the need to develop unit ramp rates based on the technical capabilities of the installed equipment.

Table 1-1 summarizes a number of nominal ramp rate improvements reported in the literature for fossil fuel generation.

Table 1-1
Industry reported fossil- fuel ramp rate improvements

Type of Fossil Fuel Generating Unit		Nominal Ramp Rate (MW/min)	
Fuel	**Technology**	**Original**	**Improved**
Coal (Lignite)	Subcritical Cyclone	2	7
Coal	Subcritical PC	3	25
Coal	Subcritical PC	1	3
Coal/FO	Subcritical PC/FO	2.5	10
Coal	Supercritical PC	3	12
Coal (Lignite)	Supercritical PC	5	15
Natural Gas	Subcritical CC Conventional	19	24
Natural Gas	Subcritical CC Flex Design	34	43

PC – pulverized coal CC – combined cycle

These improvements were achieved through changes to control logic, modification of operating procedures, adjustments in operating limits, and upgrades of equipment.

The information in Table 1-1 indicates a wide range in the unit ramp rate improvement achieved. The details of design and operation, as well as unit condition, impact the specific improvement that can be achieved by any specific fossil fuel generating unit. A methodical approach, as detailed in this report, is required to diagnose and implement individual unit ramp rate improvements.

Figure 1-2 illustrates the six areas of unit operation where changes to improve the unit ramp rates can be expected.

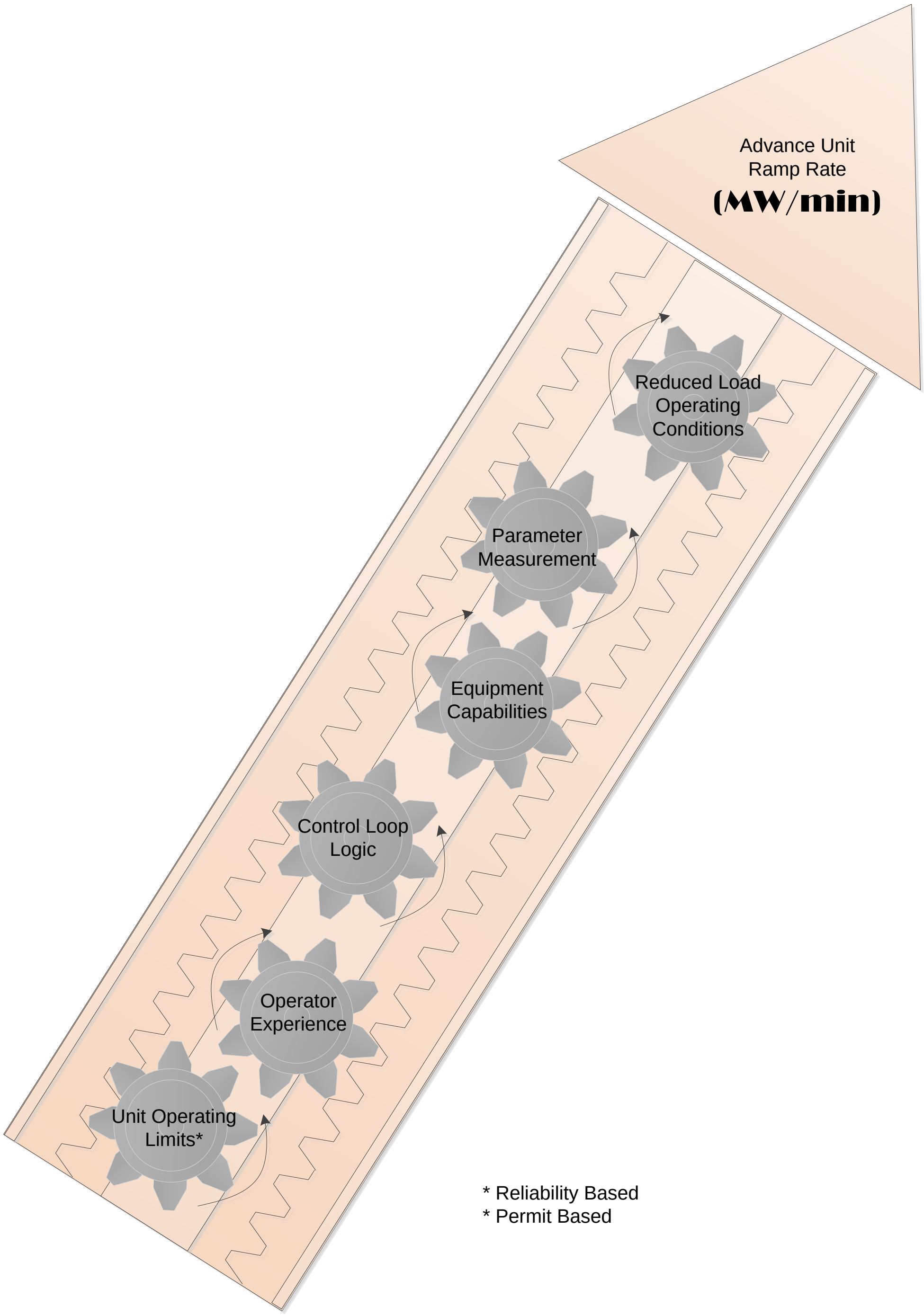


Figure 1-2
Areas to evaluate to advance unit ramp rate

Changes in one or more of these areas can provide the driver for advancing the unit ramp rate beyond the current limit. The methodology explained in this report provides a roadmap to identifying and implementing the specific changes to improve the ramp rate for a fossil fuel generating unit.

Scope

This report is intended to equip power plant personnel to identify and implement changes to increase the ramp rate of a specific unit. This effort will require collaboration between plant engineers, unit operators, and instrumentation & control personnel. The methodology addresses (1) the initial evaluation of the unit ramping capabilities, (2) diagnosis of the operating conditions contributing to ramp rate limits, and (3) development and implementation of changes to address each element of the desired ramp rate improvement. In addition to presenting the methodology, this report highlights the challenges, vulnerabilities, and steps for advancing the unit ramp rate.

The methodology detailed in this report is based on research of industry experience reported in the literature, specific experience with modifying unit operating conditions, and pilot implementations of the unit ramp rate methodology. Section 2 provides an overview of the methodology to facilitate decision making regarding undertaking the effort to advance the unit ramp rate on a specific fossil fuel generating unit. A general idea of the personnel and schedule requirements to successfully implement the methodology is provided. The keys to successful advancement of the unit ramp rate are also highlighted.

Section 3 describes the specific steps in the unit ramp rate optimization methodology. The inputs required for each step are defined, along with instructions on the execution of each step. Appendix A provides examples of the documentation to be developed to support the execution of each step. The guidance helps illustrate the actions included in the methodology and was developed based on the information from the pilot implementation.

Technical guidance to support applying the unit ramp rate optimization methodology is provided in Section 4. The evaluation approach to diagnose limits in the key unit control loops is provided. A brief primer on control loops is also provided to ensure there is no confusion concerning the nomenclature used in the technical guidance.

Section 5 identifies the case studies completed to support the development of the unit ramp rate improvement methodology. Detailed information from the case studies is provided in separate appendices, each addressing a different fossil fuel generating technology (e.g., Appendix B describes the pilot implementation at one test plant). Each of the appendices provides technology-specific guidance concerning the diagnosis and mitigation of limits concerning the unit ramp rate. The specific impacts on the unit ramping control logic are highlighted in the findings from each case study. Recommendations for performing observations during the diagnosis of existing unit operations and the keys to advancing the unit ramp rate are also provided in each appendix.

References for the ramp rate methodology development are summarized in Section 6. Additional references applicable to specific fossil fuel generating technologies are included at the end of the applicable appendix.

2
OVERVIEW

Ramp Rate Methodology

Figure 2-1 provides an overview of the methodology for improving ramp rate. The methodology consists of three tasks, some with multiple steps:

- A three-step process for developing bases for advancing the unit ramp rate;
- A step for diagnosis of improvement areas; and
- A three-step process for implementing unit ramp rate changes.

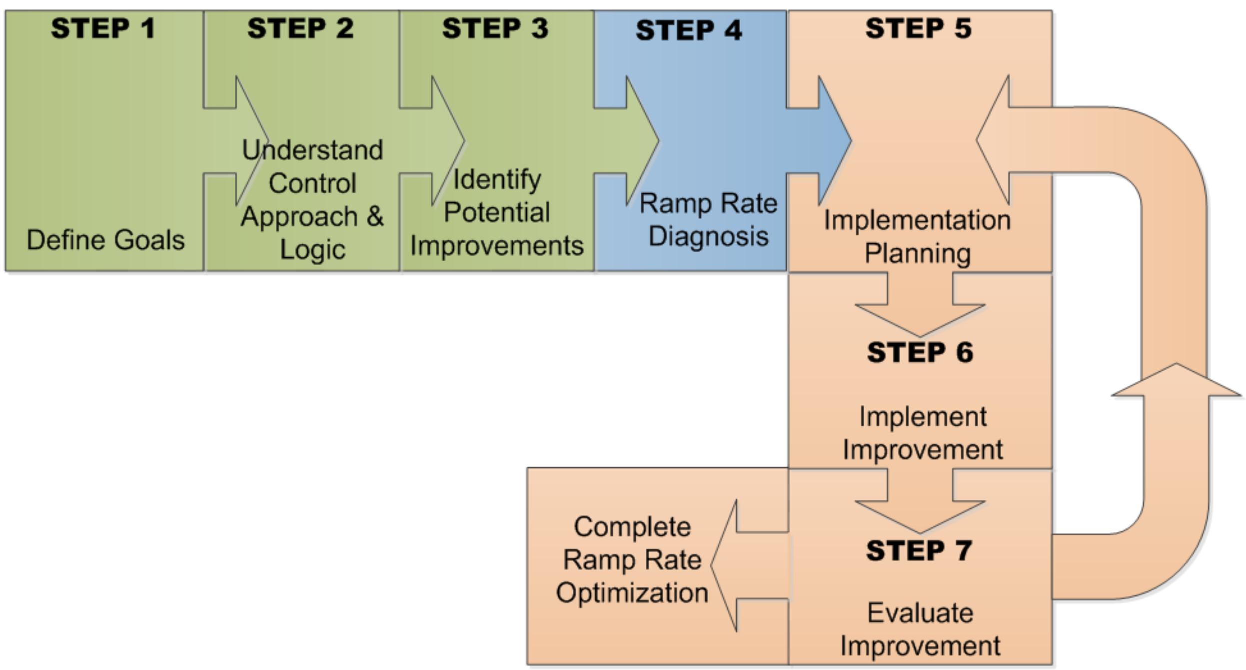


Figure 2-1
Methodology overview

This overall methodology is designed to scale as necessary to fit with the project needs. The methodology can be performed as an iterative process if necessary. The steps for implementation of unit ramp rate changes is an iterative process to ensure that each specific change is implemented separately to accommodate tuning of the effect on the unit operation.

The specific goals of each step in the methodology are:

Bases Development	
Step 1:	Define starting point(s) and goal(s) for ramp rate improvement. Assemble key unit information.
Step 2:	Evaluate unit design and control logic information for limits. Assemble operating data on current unit ramping.
Step 3:	Evaluate operating data for limits. Develop a diagnosis plan.
Diagnosis	
Step 4:	Observe unit ramping and adjustments for improvement. Define ramp rate improvement recommendations.
Implementation of Improved Ramp Rate	
Step 5:	Develop implementation plan for a selected improvement.
Step 6:	Implement selected improvement. Observe improvement in unit ramp rate.
Step 7:	Evaluate improvement against goal(s). Determine need to implement next priority improvement.

Section 3 of this report details the processes included in each unit ramp rate optimization step. Section 4 provides technical guidance on factors impacting advancement of the unit ramp rate.

Methodology Implementation Documents

The methodology is facilitated by the use of standardized documentation. Table 2-1 provides a checklist of the documents produced in each step of the ramp rate optimization methodology.

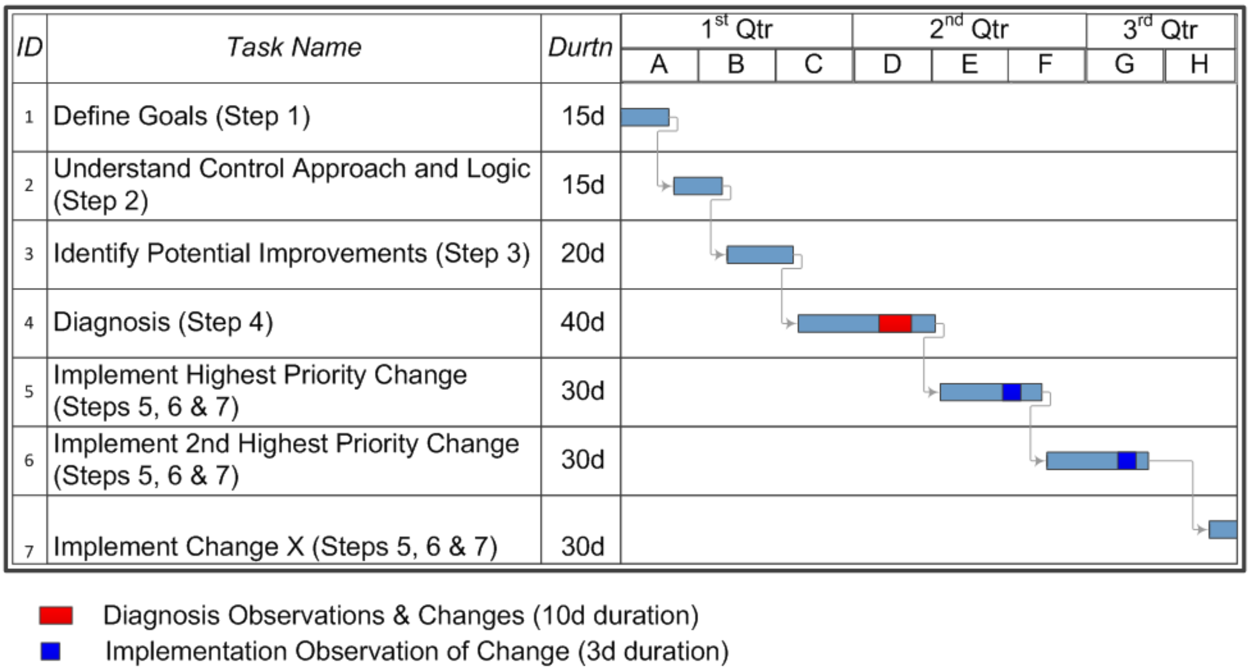
Table 2-1
Checklist of documents produced

Step	Document Type
1	Project Charter
	RFI for Existing Configuration
2	RFI for Key Loop Operations Data
3	Potential Improvements Table
	Ramp Rate Observation Plan
4	Improvement Recommendations Table
5	Implementation Plan
7	Lessons Learned Memo

Appendix A provides examples of the standardized documents. These products can be customized to match the characteristics of each generating unit.

Optimization Schedule Considerations

Figure 2-2 provides a nominal schedule for implementing the unit ramp rate optimization methodology. System constraints on scheduling the ramp rate diagnosis (Step 4) may extend the overall schedule particularly depending on the pattern of the current system generation demand.



Estimated duration for items 5, 6, and 7 in schedule should be based on "Implementation Durations" shown below.

<u>Estimated Implementation Durations</u>

- Control Logic Change	30d
- Operating Procedure Change	20d
- Instrument Calibration Adjustment	10d
- Instrument Addition	60d
- Operator Change/Addition	80d
- Other Equipment Change/Addition	140d

Figure 2-2
Methodology scheduling

The nominal schedule illustrates the expected durations associated with various categories of implementation actions. The individual implementation actions will need to be scheduled in series based on their assigned priority from Step 4. Steps 5, 6 and 7 will need to be scheduled for each individual implementation action required to achieve the overall goals for advancement of the unit ramp rate.

Methodology Staffing

The advancement of the unit ramp rate requires utilization of a number of technical and experience-related skills. As illustrated in Figure 2-3, this can best be accomplished by having a single technical lead who acts as an integrator. The integrator provides the focal point for the unit ramp rate optimization and utilizes the input from several different groups familiar with the design and operation of the unit.

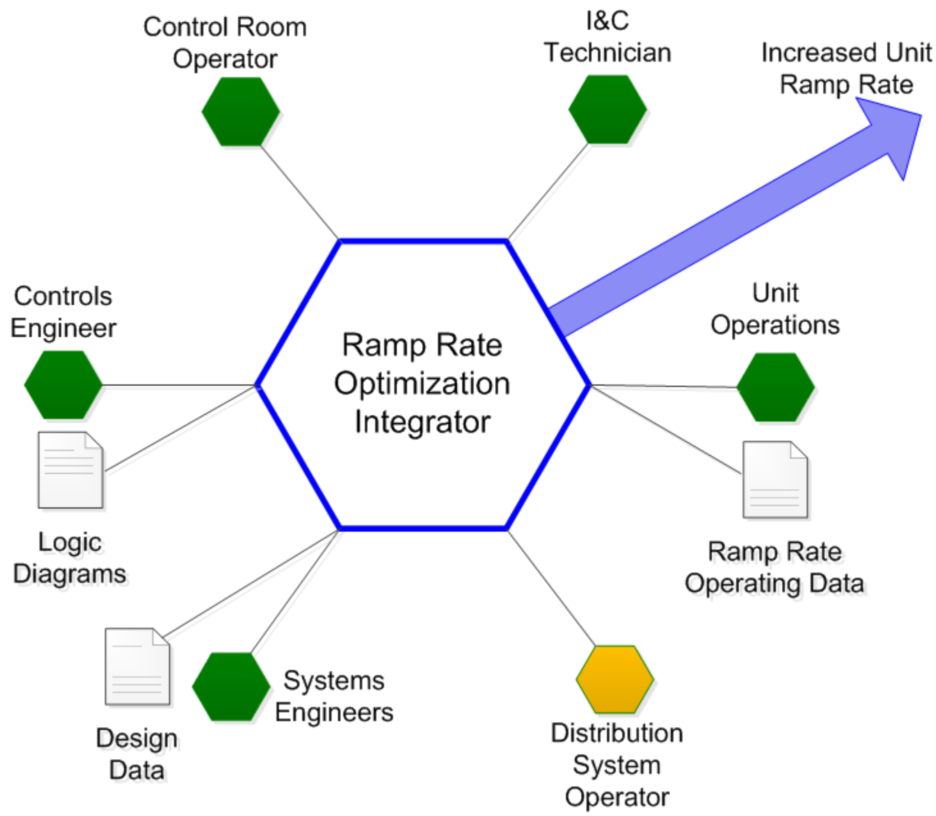


Figure 2-3
Methodology staffing model

A plant systems engineer familiar with the operation of the unit systems and limits is best suited for the role of integrator. A background in the details of the control logic for the unit is helpful, but not necessary, as the methodology provides a suitable approach for developing necessary guidance in this technical area. Availability of appropriate unit personnel as indicated in Figure 2-3 is significant to timely completion of the unit ramp rate optimization methodology. The specific engagement required from the unit personnel is detailed in the methodology description in Section 3.

Keys to Success

The overall key to improving the unit ramp rate is systematic implementation of the seven methodology steps defined in this report. This methodical approach will characterize all of the factors to be addressed and assure that the implementation can support continuous improvement.

Every unit is unique based on its design, operating history, and as-found condition and therefore will have slightly different opportunities for improvement. It is crucial that throughout the process the user seeks input from people who are familiar with the unit's circumstances to help tailor the process to the individual unit. Engagement of the unit operators and instrument & control technicians in the effort is vital. It is also important to identify any specific controls or system expertise that should be provided to the ramp rate improvement project. Depending on the expertise available at the generating station, these resources may be involved on-site to complete specific actions or remotely for reference purposes only.

Table 2-2 highlights the key actions required in each step to ensure a complete and safe increase in the unit ramp rate.

Table 2-2
Keys to ramp rate improvement success

Methodology Step	Keys to Success
1. Define Goals	• Determine specific value of unit ramp rate as improvement goal • Evaluate ramp rate impact on frequency of call for unit operation under normal system conditions • Assemble team to support optimization of unit ramp rate
2. Understand Key Parameters	• Use control system data historian capabilities to facilitate review of control logic for specific parameters impacting unit ramp rate • Evaluate control curves at load range extremes to understand unit ramp rate impact • Understand bases of specific alarm limits on unit operation
3. Identify Potential Improvements	• Consider all potential sources of unit ramp rate limits (see Figure 1-2) • Identify specific control loop responsible for limiting behavior in operating parameters • Use operating personnel input to understand challenges and previous experience
4. Ramp Rate Diagnosis	• Review potential operational changes with control room operator prior to test and solicit operator input • Verify operator response to any limit encountered prior to implementing change • Document control actions, both automatic and manual, and cause/effect of each action implemented during unit load ramp • Discuss operator reaction to unit operation during ramp once steady state has been achieved • Document conclusions from each unit load ramp observed immediately following ramp run
5. Implementation Planning	• Implement one change at a time to avoid unintended consequences and have attributable outcome • Make use of control system simulations to demonstrate control logic changes before live demonstration • Follow good engineering practices for documentation and validation of each planned change

Table 2-2 (continued)
Keys to ramp rate improvement success

Methodology Step	Keys to Success
6. Implement Improvement	• Use existing work control processes to ensure that changes are safely implemented • Implement changes individually on each unit to account for differences • Observe a unit load ramp to verify implemented change advanced unit ramp rate as expected
7. Evaluate Improvement	• Use overall goals to determine the benefits of pursuing additional changes • Share conclusions with unit operations and maintenance personnel and solicit comments

3
OPTIMIZATION METHODOLOGY

Unit ramp rate optimization at an operating fossil-fired unit requires an organized approach to diagnose limiting features of the established unit ramp rate and opportunities for increase. Figure 3-1 illustrates the seven steps included in the unit ramp rate optimization methodology. This section details the inputs, actions, and outcomes for each of these steps.

The key inputs to the methodology steps are shown to the left of the methodology steps on Figure 3-1. Examples of the documents developed to facilitate the methodology, indicated to the right of the methodology steps on Figure 3-1, are provided in Appendix A.

The objectives and approach to completing each step in the unit ramp rate optimization methodology is detailed in this section. The source documents and discussions required to diagnose the existing unit ramp rate are addressed. Use of the documentation developed in executing the methodology is also discussed. Additional information on specific technical evaluations involved with unit ramp rate optimization are discussed in Section 4.

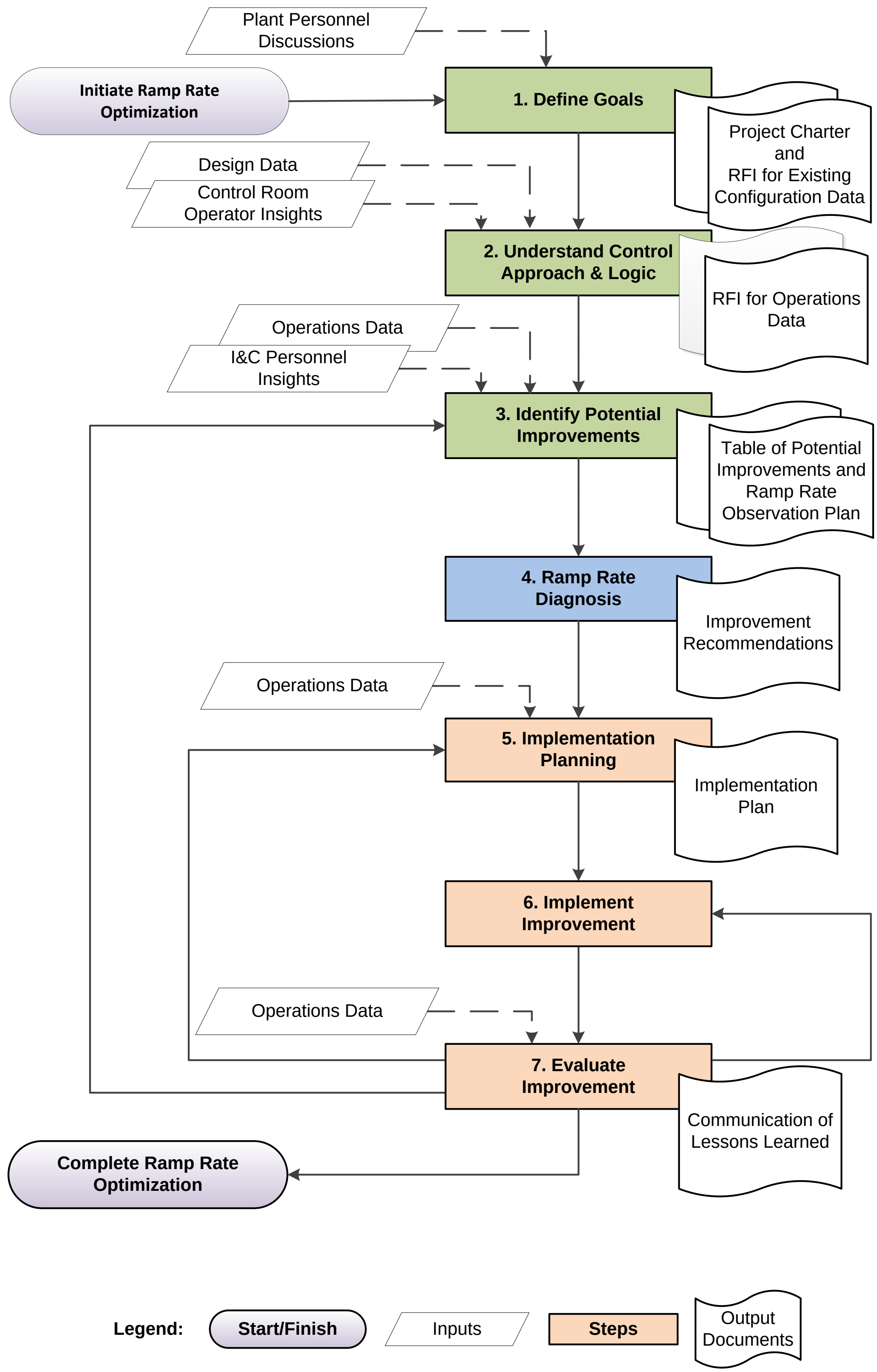


Figure 3-1
Methodology

Define Goals (Step 1)

The purpose of Step 1 is to set up the project for success by defining project objectives and the project starting point. The documents produced at the end of this step, the Project Charter and the Request for Information (RFI), are intended to support the work going forward.

Through development of the Project Charter the user will be able to identify resources and goals for the project. Both will be discussed in detail in subsequent sections. The RFI will help the user identify the inputs and, if applicable, request them from the plant.

The actions in this step enable the user to answer to the following questions:

- What are the ramping load upper and lower bounds?
- Is this ramp rate improvement for up or down ramps or both?
- How frequently will the plant need to exercise this ramp rate?
- What are the key inputs needed?

Project Charter

Developing a Project Charter is a key function of the first step. The Project Charter lays out the roles and responsibilities, current conditions, and the desired outcome for the project. This provides structure for making changes to plant procedures as well as a frame of reference for assessing the success of the ramp rate improvement project. Aspects of the Project Charter are discussed below. For additional guidance see Appendix A.

Roles and Responsibilities

The project team should be defined at the onset of the project. It may be a single plant engineer or a team of people. It is expected that the project team will be the primary users of this document and will therefore be referred to as “the user”. The user will be responsible for developing the Project Charter which will document the members of the project team.

Stakeholders are individuals who will be providing feedback or approval during the project. They may include the Plant Manager, the Operations Manager, or other key personnel. Throughout this methodology there are steps during which the user will make recommendations for changes to the plant configuration, control systems programing, or operating procedures. The process for getting stakeholder approval should be documented in the Project Charter.

Definition of Current Ramp Rate

Key to improving the ramp rate is understanding the current capabilities of the unit. To support this definition, the following information should be documented in the Project Charter:

- Stable minimum load,
- Stable full load, and
- Current ramp rate(s).

This methodology is intended for use between existing stable minimum and full loads. Ramping in unstable load zones is outside the scope of this methodology. Stable operation is defined as a load condition where the unit can operate for an extended period of time.

Understanding the current ramp rate(s) is also important because it provides the starting point for improvement. The current ramp rate might depend on the load region through which the unit is ramping. For the purposes of the optimization methodology, three regions should be considered:

- **Initial Ramp Rate:** Rate of load change when initially advancing load from minimum; often associated with additional actions required to bring burners on-line or add an additional feed water pump.
- **Nominal Ramp Rate:** Rate of load change applicable to most of the load change between minimum and full load.
- **Approach Ramp Rate:** Rate of load change when approaching full load; often associated with controls near or at the end of their range at full load.

Figure 1-1 illustrates these three regions of the unit ramp rate profile.

The information identified concerning the current ramp rate(s) is useful for determining ramp rate improvement goals. The existing unit ramp rate characteristics should be reviewed with the project team and stakeholders.

Definition of Desired Improvement

Defining the desired improvement is important as it provides guidance for determining when to stop improving ramp rate. The user should work with the stakeholders to define the goals of the project. Some sites may wish to make ramp rate improvement a continuous, ongoing process, while others may set a ramp rate goal to meet. The ramp rate goals may be directed at ramping up, down, or both. In addition to the improvement goals, expectations for the frequency of the ramp should be outlined. All goals should be documented in the Project Charter.

Areas of Concern

At the project initiation, the project team should document any known areas of concern for improved ramp rates. These can be useful guides for analyses, which will be performed in later steps of the project. An example of one of these areas might be a control valve that is not able to move through its full stroke. Talking with operators is a good way to identify areas of concern but other plant personnel may be able to provide insight. Table 3-1 provides examples of questions that can be used to guide discussion with plant personnel as the Project Charter is created.

Table 3-1
Example areas of inquiry with plant personnel

Plant Management Personnel	
1.	Objectives for increased unit ramp rate?
	• Requests from system operator?
	• Value to plant?
2.	Regular ramping requests
	• Time of day and magnitude of load change?
	• Future ramping expectations?
Control Room Operators	
1.	Current operating procedure restrictions on ramp rate
	• Temperature limits? Alarms?
	• Vibration limits? Alarms?
2.	Operational stability during ramping?
	• Steam flows? Temperatures?
	• Flue gas flows? Temperatures?
	• Combustion?
3.	Steps required to start equipment during ramping
	• Mills
	• Burners and igniters
	• Boiler feed water pumps
	• SCR ammonia injection or flue gas sorbent injection
4.	Equipment-imposed limits on ramp rate (may be design or condition related)
	• Valve operators
	• Damper operators
Maintenance Personnel	
1.	Equipment condition that may limit ramp rate?
	• Mills
	• Burners and igniters
	• Boiler feed water pumps

Table 3-1 (continued)
Example areas of inquiry with plant personnel

	Maintenance Personnel
2.	Equipment condition with cycling concerns
	• Boiler tube conditions
	• Combustion turbine conditions
	• Steam turbine conditions
	• Boiler feed water pumps
	Engineering Personnel
1.	Vendor-recommended load change limits? Technical basis?
	• Boiler
	• Steam Turbine
	• Combustion Turbine
2.	Control logic limits on ramp rate?
	• Operating curve values?
	• Feedback limits?

Current Condition RFI

To perform the analysis planned for Step 2, documents that describe the current condition of key plant control systems will need to be gathered. To gather these documents an RFI for current condition documents will be prepared. It is important to focus on documentation that shows the current condition of the controls system, rather than original design, because the goal is to understand the plant as it currently operates.

Documents will be collected based on system or control loop. The control loops of interest vary depending on the type of unit. Section 4 contains a subsection on key control loops. This section will help you identify the systems and control loops for which you will be requesting information. For each system or loop of interest the following types of documents should be requested:

- P&IDs
- Logic Diagrams
- Design Limits

This methodology recommends producing an RFI, however depending on the user’s access to plant information the RFI may be used as a checklist. Regardless, these documents should be collected for use in subsequent steps. Appendix A provides more detailed guidance for developing an RFI.

Understand Key Parameters (Step 2)

The purpose of Step 2 is to use the data received from the RFI for current condition documents to determine the data points of interest and to develop an RFI for operations data for a recent ramp.

The actions in this step enable the user to answer to the following question:

- What are the parameters on which to focus when reviewing data from past ramps?

Identifying and requesting only data points of interest makes data gathering more focused and the analysis more manageable. Additionally, during the process of identifying data points to request the user should focus on becoming familiar with the existing control loops. This familiarity will help in Step 3 when the user is identifying causes for poor control.

Parameter Assessment

The types of control loop parameters that are important for this methodology include (see Section 4 for descriptions of this terminology):

- Set point
- Manipulated parameter
- Directly controlled parameter
- Final control element (if available)

The goal of this task is to identify data points for which to request operating data and to identify the key systems of interest for ramp rate observations. The following bullets and tables provide guidance on assessing plant control loops for this goal.

- Break complicated control loops into their fundamental parts. This can often be done by examining one parameter at a time and working "outwards" from that parameter to related parameters. Table 3-2 provides guidance to organize a review of control logic diagrams.

Table 3-2
Analysis of control logic diagrams

System and Parameter	Drawings	Notes and Functions	Limits
Chose a control loop and a parameter from that loop.	List which control logic drawings cover the selected parameter. This helps create an index of drawings. Adding notes about key drawings can be helpful. Notes may include some of the following: • Drawings that contain final control elements such as valves. • Relationships with other key parameters.	Document key aspects of the control loop such as: • Input signals used to generate the parameter in question. • Output signals that the parameter leads to. • Functions that are used on the parameter, including the graph of the function if possible.	Control logic diagrams often contain system limits. These should be documented for comparison against operating data.

- Use the control system vendor's manual to help in reading the control diagrams. Contacting the vendor to get documentation on their control systems can be key to understanding the different functions that are used.
- Document control limits that are shown on the control logic as well as other permit limits. The development of a table of limits will be used in Step 3 to provide context to the operating data. Table 3-3 provides guidance for considering parameter limits.

Table 3-3
Table of limits and operating data

Parameter	Design Limit	Starting Value	End Value	Notes
Choose a parameter of interest.	Document the design limit. Limits may be found in the following locations: • Control logic diagrams. • Vendor documents. Check limits with plant personnel if there are questions.	During Step 3 and Step 4, document the initial value of the parameter (at the start of the ramp).	During Step 3 and Step 4, document the final value of the parameter (at the end of the ramp).	Add notes about the behavior of the parameter during the ramp as necessary.

Operating Data RFI

When requesting ramp data, recent data is preferred as this reflects the current condition and configuration of the unit.

Table 3-4 provides example parameters of interest for each control loop at a steam generating unit. Table 3-5 provides example parameters of interest for a combined cycle unit. Section 4 provides more background on control loops.

Table 3-4
Key control loops impacting steam generating unit ramp rate

Identifier	Example Equipment/System Controlled	Example Parameters
Unit Demand Management	System Load Demand Unit Runback/Rundown High/Low Load Limit Ramp Rate	Table B-1
Furnace Draft Control	ID Fans/Dampers Booster Fans/Dampers Flue Gas Recirculation Fans/Dampers	Table B-2
Steam Temperature Control	SH Attemperation Valve RH Attemperation Valve Burner Tilts Backpass Dampers	Table B-3
Firing Rate Control	Feeders Mills Igniters FD Fans/Dampers	Table B-4

Table 3-4 (continued)
Key control loops impacting steam generating unit ramp rate

Identifier	Example Equipment/System Controlled	Example Parameters
Feed Water Control	Feed Water Pumps Recirculation Valve Drum Level Deaerator Level	Table B-5
Steam Turbine Management	Main Steam Throttle Valves Intercept Valves Turbine Supervisory System	Table B-6

Table 3-5
Key control loops impacting combined cycle unit ramp rate

Identifier	Example Equipment/System Controlled	Example Parameters
Unit Demand Management	System Load Demand Unit Runback/Rundown High/Low Load Limit Ramp Rate	Table C-1
Combustion Turbine Control	Combustion Turbine Supervisory System Fuel Control Valve Inlet Guide Vane	Table C-2
Steam Turbine Control	Steam Turbine Supervisory System Main Steam Control Valve LP Turbine Admission Control Valve	Table C-3
Steam Temperature Control	SH Attemperation Valve RH Attemperation Valve	Table C-4
Feed Water Control	Condensate Pumps Feed Water Pumps Recirculation Valve HP/IP/LP Drum Levels	Table C-5
Duct Burner Management	Fuel Valve Igniter	Table C-6

Identify Potential Improvements (Step 3)

The purpose of Step 3 is to identify and document poorly controlled parameters in a Table of Potential Improvements. Operating data collected in Step 2 (requested using the RFI developed in Step 2) will be used for this purpose.

The actions in this step will enable the user to answer to the following questions:

- Which process parameters have room for improvement?
- What changes can be made to improve those process parameters?

Section 4 provides information on how to assess the operating data to determine which parameters show unacceptable variation and have the opportunity for improvement. Additionally, plant instrumentation and control (I&C) personnel should be consulted to gather insights on instrumentation and control device operability. Understanding the operability of the components in a control loop will help to identify the areas for improvement. Table 3-6 provides guidance for discussions with I&C personnel.

Table 3-6
Example areas of inquiry with I&C personnel

Instrument Condition (Availability, Accuracy, and Calibration)
• Flue Gas Thermocouples
• Flame Scanners
• Boiler O_2 Monitors
• Feeder Speed Indication
• Feed Water Flow Measurement
• Feed Water Valve Position Operators/Indicators
• Steam Valve Position Operators/Indicators
• Fan Damper Position Operators/Indicators
Instrument Loop Response (Time from signal to feedback)
• Steam Valve Position
• Fan Damper Position
• Feed Water Valve Position
Maintenance I&C Backlog
• Trend
• System/Instrument Priority
Abandoned Instrumentation (Location, Duration OOS, and Reason)
• Recent (2 Years) Decisions
• Long-Term Decisions

When observing the operating data, the following approaches can be used to facilitate the process:

- Determine the time period that shows a characteristic ramp.
- Graph operating data during that time period. Charts help the user identify patterns and trends in data.
- Note the starting and ending values of parameters (see Table 3-3). Comparing the start and end values to the limits may help identify areas where the control can be improved.

This work leads to development of two documents: a Table of Potential Improvements and a Ramp Rate Observation Plan. Those documents are described below. Additional guidance on the content of the Table of Potential Improvements as well as the Ramp Rate Observation Plan can be found in Appendix A.

Table of Potential Improvements

The purpose of the Table of Potential Improvements is to document the findings of the operating data review. The table should include the following information:

- List of data points that have unacceptable variation
- List of potential causes and improvements

Ramp Rate Diagnostic Plan

This plan communicates to stakeholders how the Ramp Rate Observations Diagnostics will be performed (Step 4), and should include:

- Agenda for Ramp Rate Observation
- Description of modifications to ramping approaches that will be considered for testing

Ramp Rate Diagnosis (Step 4)

The purpose of this step is to observe multiple ramps, both in the as found condition and with changes implemented that test the theories developed in Step 3. The results of these ramps will help the user determine changes for permanent implementation in Steps 5 through 7. Figure 3-2 shows the detailed steps for performing ramp rate diagnostic testing that will be used in Step 4.

The actions in this step enable the user to answer to the following questions:

- What were the effects of the changes?
- Which changes should be considered for permanent implementation?
- Have you returned the system to the as found condition after all ramps and observations are complete?

Each step of the process will be discussed in detail in subsequent subsections.

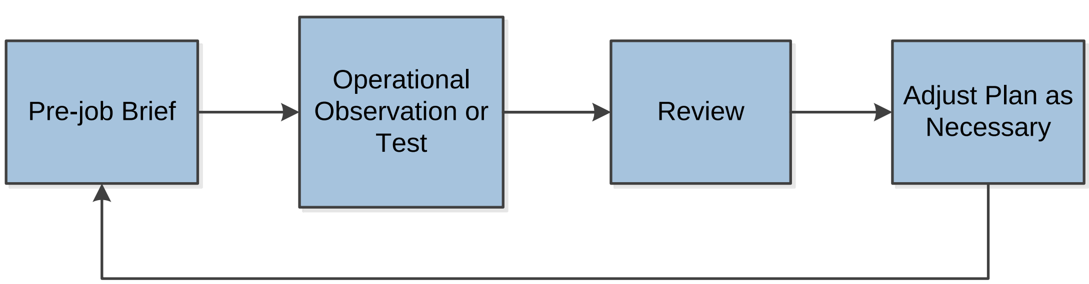


Figure 3-2
Ramp rate diagnostic details

Pre-Job Brief

During the pre-job brief, the project team, unit operations personnel, stakeholders, and other appropriate individuals should discuss the next planned ramp. Items that should be discussed include:

- Unit configuration prior to the ramp,
- Changes from normal ramping approaches,
- Data points to be collected,
- Physical equipment to be observed, and
- If applicable, modifications to the plan based on the results of the most recent ramp.

Observations

Step 4 is intended to be iterative and flexible based on the needs of the unit. During each ramping observation, the user can make either baseline or modification observations. Ideally, one ramp will be performed (either a baseline or modification) and then the user will move to review the results prior to the next ramping observation.

The types of ramps are described below.

Baseline

A baseline ramp is performed with no modifications to the controls or physical components in the plant. Observing this type of ramp ensures a solid understand of the existing ramp rate and limitations. In Step 3 of this process, theories were developed regarding what parameters presented an opportunity for improvement. Baseline ramping observations allow the user to directly observe those parameters prior to making changes.

This is also an opportunity to gather information on the physical condition of the components in each system in the plant and how well they operate. Understanding the physical condition of the components will provide context for ramp rate data.

Modifications

A modification ramp provides an opportunity to confirm approaches to improve ramp rate. During these tests the user may change a control parameter or operational practice to determine its effect on ramp rate. The items to change will be based on the Table of Potential Improvements (Step 3).

It is good practice for the user to thoroughly document what set points or other items are being changed. This includes the as-found setting or configuration. This is important because the system should be returned to its as-found condition once testing is complete.

Review

After a baseline or modification ramp is performed, the data collected should be reviewed to determine if the parameters behaved as expected. A review after a baseline ramp may look for expected behavior, confirmation of hypotheses, and to determine if there are any new parameters of interest. A review after a modification ramp will also look for hypotheses confirmation and new parameters. When performing the data review, all aspects of the systems identified in Step 3 should be examined. This will ensure full understanding of system behavior.

Adjust Plan as Necessary

Based on the findings from each ramping observation, the plan for future observations may need to be adjusted. Those adjustments should be documented in the Ramp Rate Observation Plan.

Improvement Recommendations

Performing the steps shown in Figure 3-2 will provide information to guide decisions on those changes recommended for permanent implementation. These recommendations will be documented in the Improvement Recommendations document. Guidance on this document can be found in Appendix A.

The Improvement Recommendations document should discuss priorities for recommended changes. To make recommendations on specific improvements, the cost and schedule as well as the expected ramp rate improvement should be taken into consideration.

Implementation Planning (Step 5)

Based on the Improvement Recommendations developed in Step 5, an Implementation Plan will be developed. Prior to developing the plan, the Improvement Recommendations should be discussed with the stakeholders to get feedback on which of the recommendations will be implemented. It is acceptable to select only a subset of the recommendations for the initial Implementation Plan.

The actions in this step will enable the user to answer to the following questions:

- What changes will be implemented permanently?
- What is the plan for implementing the changes?
- Have all the stakeholders agreed to the plan?
- What data will be needed to assess the effectiveness of the changes?
- What are the acceptance criteria?

The Implementation Plan should address the following:

- Describe the changes
- Identify the order the changes will be made
- Describe how the changes will be implemented (e.g., modify a control setting or change a final control element)

- Describe the change approval process (e.g., the change will be implemented in advisory mode)
- Statement of data to be collected

Subsequent steps will implement the improvement and then evaluate its acceptability. Additional guidance on the implementation plan can be found in Appendix A.

Implement Improvements (Step 6)

The improvements should be implemented following the Implementation Plan. When the improvement is implemented, a ramp should be performed and data gathered. Prior to moving on to Step 7, the user should be able to answer the following questions:

- Have we implemented the items as described in the Implementation Plan?
- Was the necessary data collected?

Evaluate Improvement (Step 7)

The evaluation step focuses on determining the success of the most recent changes as well as the project overall.

The actions in this step enable the user to answer the following questions:

- Was the change implemented in Step 6 successful?
- Are there more changes to be made via the Implementation Plan?
- Does the Implementation Plan need to be changed?
- Should the project be continued overall or has the ramp rate optimization reached its end?

Figure 3-3 shows the process for evaluating actions after Step 6.

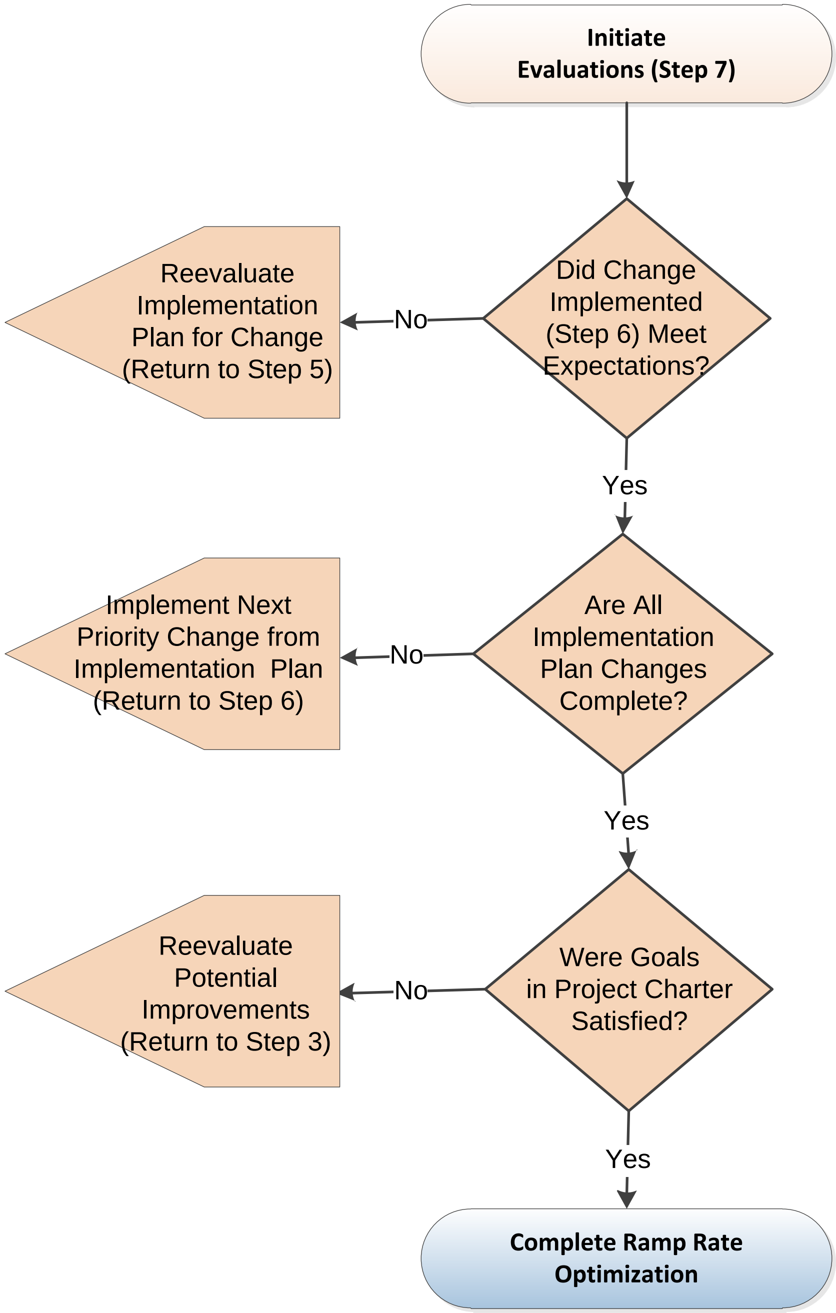


Figure 3-3
Detailed evaluation of results (Step 7)

Evaluation of Implementation Plan

Data from Step 6 should be assessed. The first decision to make is if the results are acceptable and the change is one that the project team and stakeholders wish to keep. If not the user should return to Step 5 and reevaluate the Implementation Plan.

If the most recent change was successful but the Implementation Plan is not complete, then the user should return to Step 6 and continue to work through the Implementation Plan.

Evaluation of Ramp Rate Project

When the Implementation Plan is complete, the user should assess if the project is finished. Criteria set forth in the Project Charter provides a basis for this decision. If more improvements are desired, the user should return to Step 3 and evaluate the current ramp rate data for more improvement opportunities.

If the project is determined to be complete, a lessons learned memo should be prepared to document the changes that were made and the new ramp rate.

4
TECHNICAL GUIDANCE

Improving the ramp rate of a fossil power generating unit involves the synthesis of equipment design and capabilities knowledge, control logic and instrumentation understanding, and unit operation experience. The technical guidance provided in this section explains the impacts of these diverse areas on the unit ramp rate and provides approaches for evaluating unit ramping conditions.

This section also provides a primer on control logic to ensure a consistent understanding of the terminology used in this report. The technical guidance is directed at highlighting specific areas of evaluation most common in improving the unit ramp rate.

Control Loop Basics

The following five control strategies are commonly used in power plant control:

- Simple feedback control
- Simple feedforward control
- Feedforward-plus-feedback control
- Cascade control
- Ratio control

Most power plant control systems consist of an interconnected matrix of these five types of control. The five control strategies are described further below. A glossary of terms is provided at the end of this section.

Simple Feedback Control

In simple feedback control, a directly controlled variable is compared to a set point, and the error (difference between feedback and set point) is used to generate an output signal to the manipulated variable. The controller can include proportional, integral, and/or derivative functions in determining the response to the control error. Figure 4-1 illustrates the elements of a simple feedback control loop

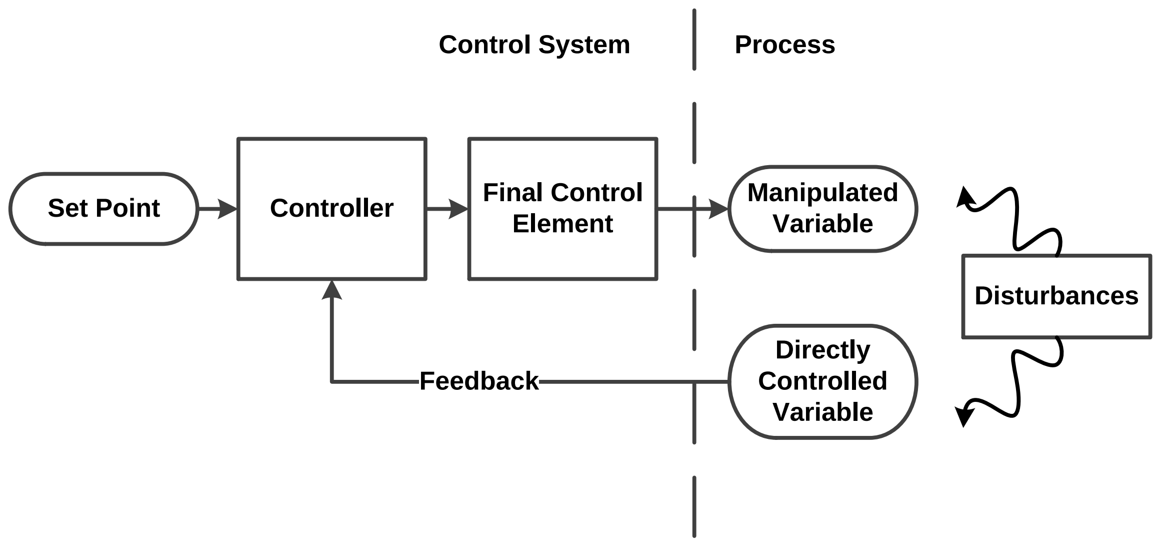


Figure 4-1
Simple feedback control loop

Simple Feedforward Control

Simple feedforward control, also known as open loop control, is illustrated in Figure 4-2. A set point is fed into a function which is built into the controller that determines the required position of the manipulated variable. The control system response is fast, and is stable since it lacks feedback. However, this type of controls depends on the accuracy of the function that relates the directly controlled variable to the set point and manipulated variable. This accuracy can be affected by how well the process is understood, and the conditions under which the function was calibrated. Lacking feedback, changes in the process or final control element can result in control errors.

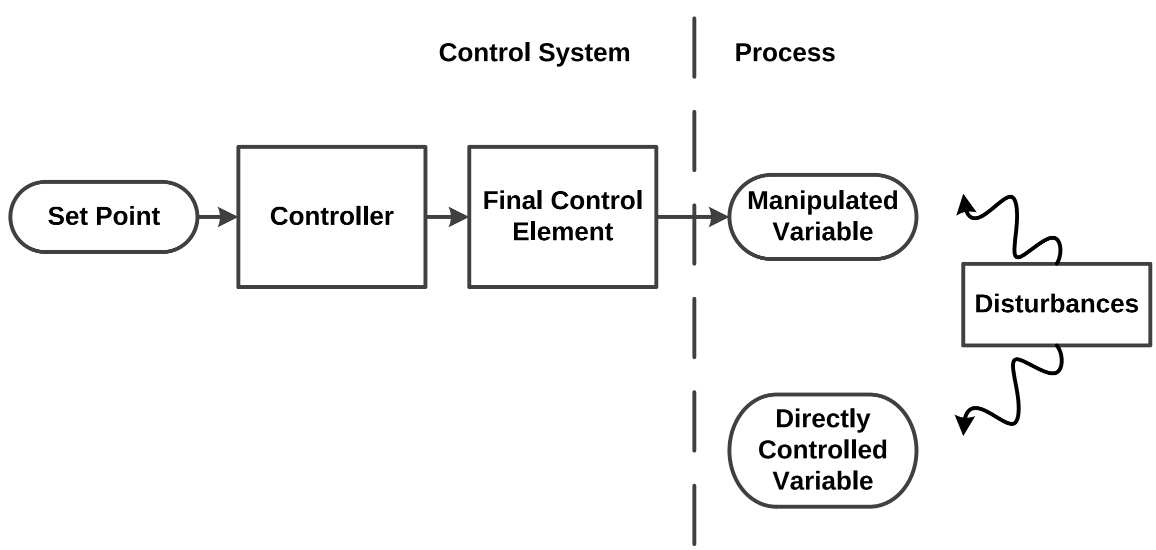


Figure 4-2
Simple feedforward control loop

Feedforward-Plus-Feedback Control

In feedforward-plus-feedback control, the set point, with a predictable relationship to the manipulated variable, is used for feedforward. Typically, the controller responds to changes in the feedforward signal before changes in the directly controlled variable initiate a control system response via the feedback signal. Figure 4-3 illustrates the elements of a feedforward-plus-feedback control loop.

The directly controlled variable is used for the feedback loop. As in simple feedback control, the controller compares the feedback to the set point to generate an error signal. The error is processed through proportional, integral, and/or derivative functions in determining the response to the control error.

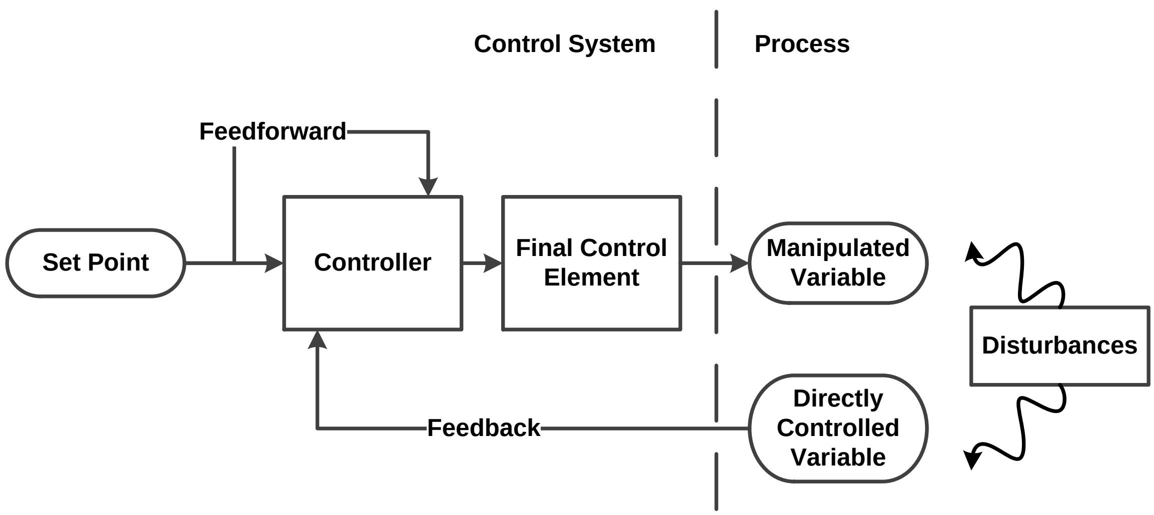


Figure 4-3
Feedforward-plus-feedback control loop

Cascade Control

Figure 4-4 illustrates the elements of a cascade control loop. In cascade control, two feedback loops are connected together with the output signal of the primary loop acting as the set point for the secondary loop. This control is often applied to stabilize the manipulated variable.

To avoid control instability due to interaction between the two control loops, the response times of the two loops needs to be significantly different. Process response of the secondary loop is typically at least 5 to 10 times faster than the primary control loop. One example of cascade control is applied drum level: level (normally slow response time) is the primary loop, cascaded to flow control (normally a fast response time).

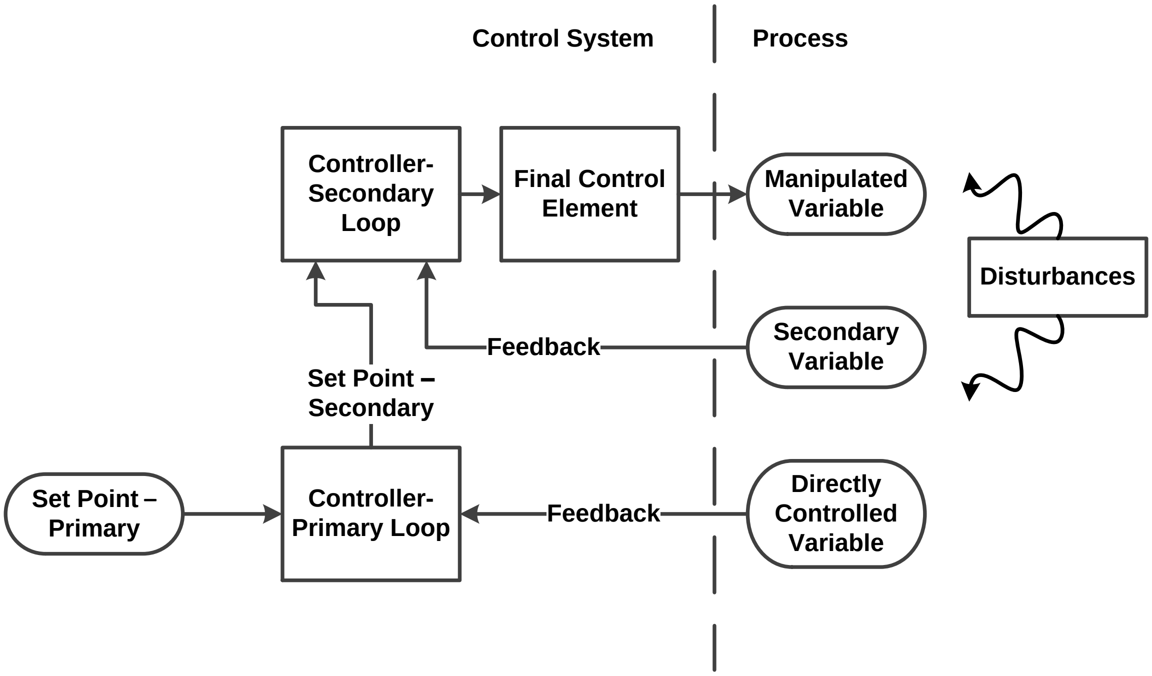


Figure 4-4
Cascade control loop

Ratio Control

In ratio control, a feedback controller uses a set point that is in direct proportion to an uncontrolled variable. This maintains a predetermined ratio between two process variables. Figure 4-5 shows the elements of a ratio control loop.

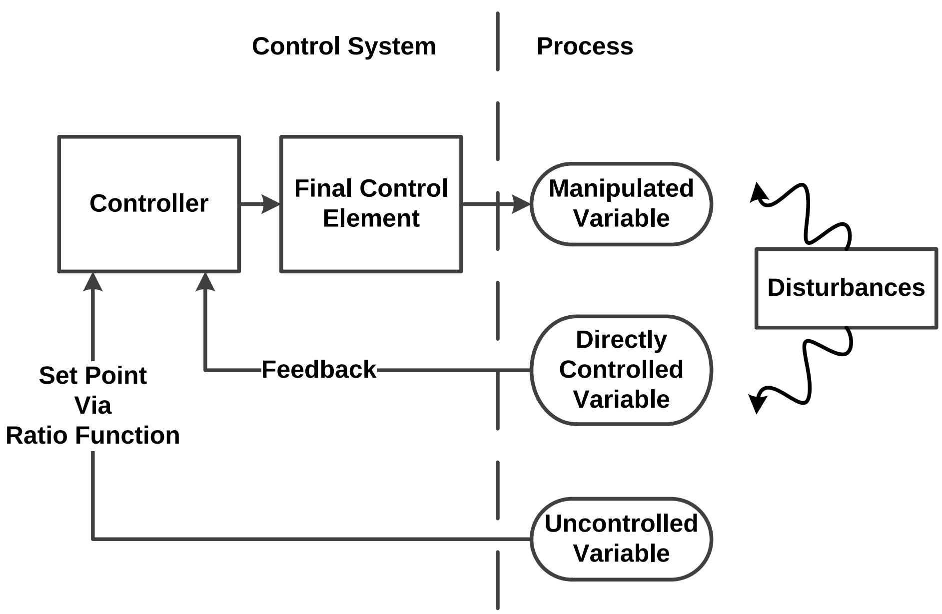


Figure 4-5
Ratio control loop

Key Control Loops

The key control loops affecting ramp rate need to be identified early in an optimization ramp rate project (e.g., Step 1 in this methodology). Figure 4-6 illustrates the key control loops that commonly manage a steam generating unit. The controls design for any specific generating unit may differ from that shown in Figure 4-6; for example, combined cycle units will have different control loops. The case studies (see Section 5) provide additional details on unit control loops.

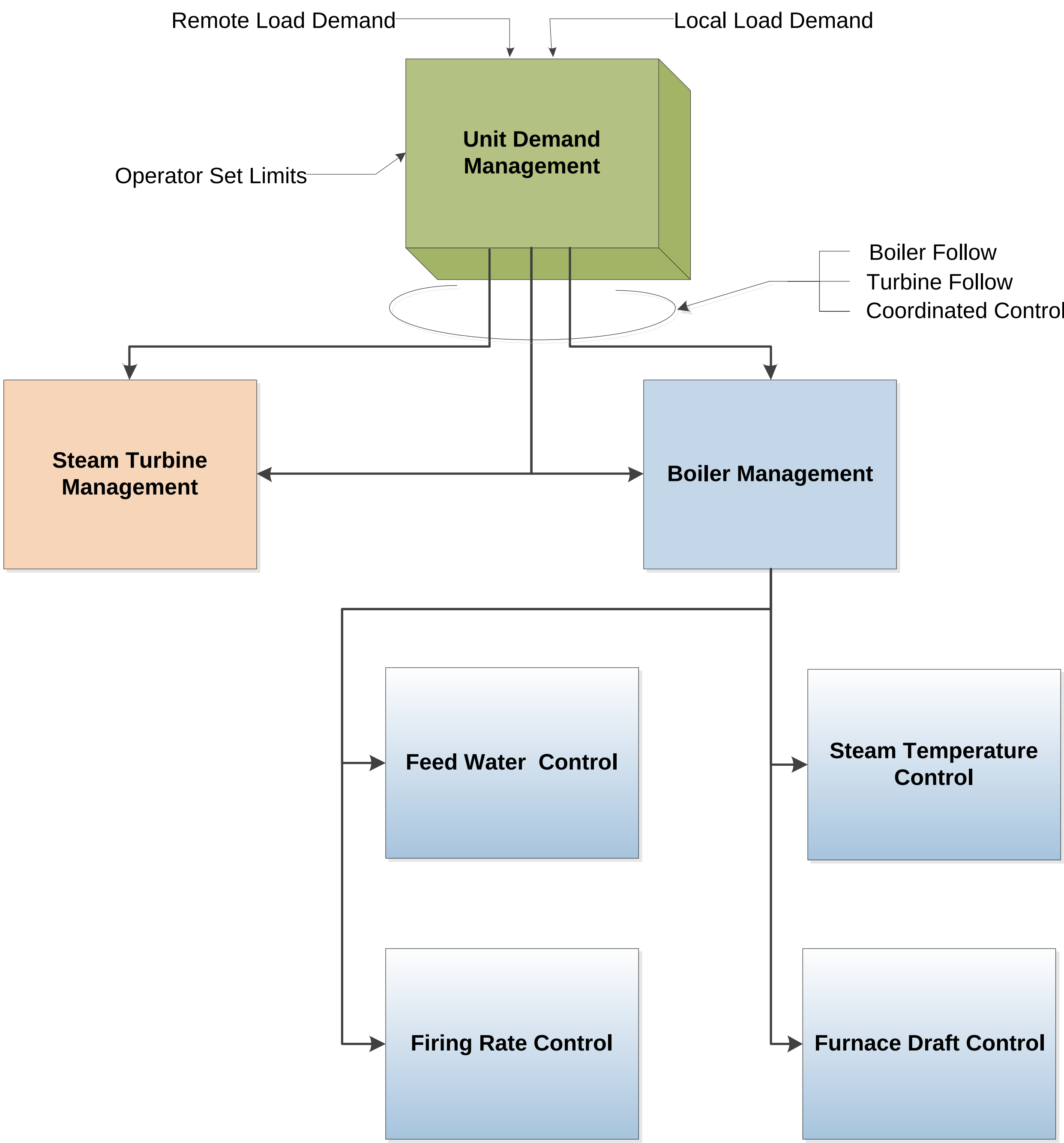


Figure 4-6
Hierarchy of key control loops (steam generating unit)

Additional control loops, not illustrated in Figure 4-6, exist in the fossil fuel generating unit that may influence the unit ramp rate. Where one of these loops is concluded to be key to the unit ramp rate of a specific unit design, the reader should develop an understanding of the control loop as discussed in the following sections.

Assessing Loop Performance

In several of the steps in the unit ramp rate optimization methodology (see Section 3) require an assessment of control loop performance. These assessments involve reviews of operations data for purposes that include the following:

- Step 3: Past ramps are reviewed to identify opportunities for improvement.
- Step 4: Each diagnosis test run is reviewed to confirm areas for improvement and to consider approaches to achieve improvement.
- Step 7: Following implementation of improvements, the results are evaluated to determine if desired outcomes have been achieved.

In assessing control loop performance, the following characteristics are indicative of poor control:

- Process alarms occur during or immediately following ramp operations.
- Manual intervention is required by operators to maintain acceptable performance.
- The directly controlled variable goes outside of design limits or into zones that result in unacceptable rates of degradation of plant components.
- The directly controlled variable moves to set points sluggishly.
- Large errors persist between the set point and the directly controlled variable.
- Oscillations of the directly controlled variable occur.
- Frequent changes to the manipulated variable degrade the final control element or other system components.
- The final control element remains in positions that degrade its condition.
- The final control element reaches its control limits (e.g., fully closed or fully open valve).

These characteristics can be observed in the operating data to support the diagnosis of the control loop changes required to improve the unit ramp rate.

Guidance for Identifying Contributors to Poor Control Loop Performance

After identifying a problem control loop, the specific contributors to the problem must be determined. Potential contributors to poor control loop performance include:

- Incorrect or incomplete understanding of relationship between the manipulated variable and directly controlled variable.
- Measurement of the directly controlled variable is:
  - Inaccurate.
  - Slow to respond to actual process conditions.
  - Not representative of spatial variations in the process.
- Set point is incorrect or does not change with process.
- Controller does not:
  - Receive set point signal correctly.
  - Receive feedback signal correctly.
  - Have proper logic to provide the correct control signal.
  - Have proper rate of response to changes in set point or feedback.
  - Provide a proper control signal.
- Final Control element:
  - Does not respond as expected to control signal.
  - Incomplete understanding of relationship between final control element and manipulated variable.
  - Reaches a control limit.
  - Logic that would improve performance is not included in the control system.

Glossary

The control loop evaluations presented in this report are based on the following common terminology:

boiler follow mode. The steam turbine generator is controlled to output a set amount of electric power, and the boiler is automatically controlled to maintain a set main steam pressure. The boiler “follows” steam turbine control valve position changes, changing fuel and other inputs to maintain the main steam pressure.

control system. A system in which deliberate guidance or manipulation is used to achieve a desired value of a *process variable*.

controller. A device which operates automatically to regulate a controlled *process variable*.

coordinated mode. Energy output of the unit is established by the unit operator or a load dispatch system, and demand signals to the turbine and boiler (both of which are in automatic control) simultaneously regulate the energy balance of the unit (e.g., fuel inputs to boiler, steam turbine inlet control valve positions, and generator electric power output).

directly controlled variable. The *process variable* whose value is measured to provide a feedback signal for the controller. Typically, control system actions are taken to maintain the *directly controlled variable* at a set point.

disturbances. Influences on the process, that come from outside the control loop of interest and that affect the value of the *directly controlled variable*. For steam temperature control, heat input to steam in the final superheater is a *disturbance* that affects the attemperation spray control loop.

final control element. The device that directly changes the value of the *manipulated variable*. Examples of final control elements include valves and dampers.

manipulated variable. A *process variable* that is changed due to the output signal from the *controller* so as to change the value of the *directly controlled variable*. On drum level control, water flow is the *manipulated variable* and drum level is the *directly controlled variable*.

process. Physical or chemical change of matter or conversion of energy.

process variable. A quantity, property, or condition of the *process* that can be measured.

set point. The desired value for a *process variable*.

turbine follow mode. The boiler is controlled based on set inputs (e.g., fuel, flow), and the steam turbine control valves automatically modulate to maintain a set main steam pressure. The steam turbine “follows” boiler steam output changes.

5
RAMP RATE IMPROVEMENT CASE STUDIES

Unit ramp rate improvement methodology can be applied to a number of generating station designs and configurations. EPRI has used its case study approach to demonstrate the technology-specific aspects of this methodology at specific types of generating units. It is expected that all major types of generating units will be demonstrated in order to complete the guidance for improving unit ramp rate.

This report currently includes unit specific case study information on the following types of power generation systems:

APPENDIX B: COAL-FIRED SUPERCRITICAL CASE STUDY (2017)

Technical Guidance

Pilot Test Ramp Rate Diagnosis

Case Study References

APPENDIX C: 2×1 NATURAL GAS-FIRED COMBINED CYCLE CASE STUDY (2018)

Technical Guidance

Pilot Test Ramp Rate Diagnosis

Case Study References

APPENDIX D: ***FUTURE CASE STUDY***

Technical Guidance

Pilot Test Ramp Rate Diagnosis

Case Study References

6
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A
DOCUMENTATION GUIDANCE

Section 3 of this report describes the methodology for improving the unit ramp rate. A number of documents are identified that facilitate the methodology. This appendix provides guidance for these documents. Where they have been created as part of EPRI's pilot case studies, example documents are provided.

Included in this appendix are the following:

- An example project charter
- An example RFI for the existing configuration
- An example RFI for key loop operating data
- An example table of contents for a Ramp Rate Observation Plan

Project Charter (Step 1)

Purpose: Document project goals and resources that will support the project.

Expected Content:

- Roles and responsibilities
- Current ramp rate
- Definition of desired improvement
- Known areas of concern for ramping

See below for a template for a Project Charter.

Project Charter – [Station and Unit #] Ramp Rate Improvement

CURRENT RAMPING CAPABILITY

Load Range	Ramp Rate
aaa-bbb MW_{NET}	*x* MW/minute
bbb-ccc MW_{NET}	*y* MW/minute

INTENDED IMPROVEMENT AND KNOWN LIMITS ON RAMP RATE

Project Objective: Improve capability of the unit to ramp load up between *aaa* MW_{NET} and *bbb* MW_{NET}. Equipment limits should be considered relative to the potential for daily ramps.

Known limits on ramping capability:

- Steam temperature control.
- Overshoot on air flow (ID fan) near full load.
- Overshoot on feed water flow (BFPs) near full load.

PROJECT TEAM MEMBERS AND STAKEHOLDERS

Name	Organization
[Name]	[Station Name], Performance Engineer
[Name]	[Company Name], Fleet Support Engineer
[Name]	[Company Name], Director, Technical Services
[Name]	[Station Name], Operations Manager
[Name]	[Station Name], Operations Superintendent

PLANNED SCHEDULE

Task	Schedule
Project Kickoff	YYYY-MM-DD
Ramping Observations	YYYY-MM-DD
Improvement Recommendations	YYYY-MM-DD

RFI for Existing Configuration (Step 1)

Purpose: Identify documents needed to understand plant design and current condition.

Expected Content:

- List questions on plant current conditions
- List of requested documents

See below for a template for an RFI for Existing Configuration.

YYYY-MM-DD
[Doc Number]

Unit Ramp Rate Optimization Methodology – [Station Unit #] – Request for Information

BACKGROUND

[Provide background for audience, including reference to methodology.]

PURPOSE

This Request for Information (RFI) lists questions, document requests, and data requests to characterize the current [Station Unit #] ramp rate and identify potential ramp rate improvements.

REQUESTS

The request for information is provided in two tables below:

Table 1 lists questions regarding unit operations and design related to ramp rate.

Table 2 provides a list of requested documents and operating data.

Table 1 includes a summary of the responses received [previously]. Follow-up questions concerning this information are noted in Table 1.

Table 2 includes a summary of documents previously provided concerning the design of the unit's systems and components. As noted in Table 2, plant personnel are requested to verify that the versions of these documents are current and provide updated versions where applicable.

Table 1
Questions regarding [Station Unit #] ramp rate

Item Number	Question	Initial Response	Additional Requested Information
1.0	**Minimum Load Operations**		
1.1	What is the current minimum achievable load for the unit?	[initial response]	[clarification question]
1.2	How frequently does the unit operate at minimum load?		Initial request.
2.0	**Ramping Operations**		
2.1	Over what ranges of load does the unit load follow?		Initial request.
2.2	What is the current ramp rate?		Initial request.
2.3	Are there load ranges over which ramp rate is higher or lower?		Initial request.
2.4	What limits the current ramp rate?		Initial request.
2.5	[initial question]		Initial request.
3.0	**Coal Supply**		
3.1	What are the sources of coal supply for the unit?		Initial request.
3.2	How much variation in coal properties (as supplied) is typically experienced?		Initial request.
3.3	Do minimum load limits or ramping limits change with coal supply? If so, describe the changes.		Initial request.
4.0	**Controls**		
4.1	What control modes (turbine-follow, boiler-follow, coordinated, etc.) are available for the unit?		Initial request.
4.2	Over what load ranges is fully automated control available? What sets the limits for automated control?		Initial request.
4.3	In which control modes are the highest ramp rates possible?		Initial request.
4.4	[initial question]		Initial request.

Table 1 (continued)
Questions regarding [Station Unit #] ramp rate

Item Number	Question	Initial Response	Additional Requested Information
5.0	**Feed Water System**		
5.1	Does the feed water control approach change with load? If so, at what feed water flow does the control approach change?		Initial request.
5.2	Have operators noted feed water regulating valve and actuator instability while ramping? If so, describe.		Initial request.
6.0	**Air Supply System**		
6.1	[initial question]	[initial response]	[clarification question]
6.2	How does excess air set point change with load? Is this automatic or operator selected?		Initial request.
7.0	**Fuel Feed System**		
7.1	[initial question]	[initial response]	[clarification question]
7.2	Identify the preferred burner/mill configuration for low load operation.		Initial request.
7.3	Identify the preferred burner/mill configuration for full load operation.		Initial request.
8.0	**Steam Temperature Control**		
8.1	What is the minimum controllable flow from the superheat and reheat desuperheater sprays? What is the maximum controllable flow to the superheat and reheat desuperheater spray? Is there any load at which the desuperheater flow is limited or not available?		Initial request.
9.0	**Furnace Draft Control**		
9.1	[initial question]		Initial request.
10.0	**Steam Turbine Generator**		
10.1	[initial question]		Initial request.

Table 2
Document/data requests for [Station Unit #]

Item Number	Description	Previously Supplied Information	Additional Request
A	**Operating Data**		
A1	Listing of all available DCS data historian (e.g., PI) tags.		Initial request.
A2	Listing of DCS alarms and set points		Initial request.
A3	Example data (e.g., Excel workbook) used to track critical process parameters while ramping.		Initial request.
A4	Lab analysis results for as-bunkered coal supply (Proximate analyses, Heating Value, and Sulfur content).		Initial request.
B	**Operating Procedures**		
B1	Operating procedures controlling minimum load operations.		Initial request.
B2	Operating procedures controlling load ramping.		Initial request.
B3	Start-up Operating Procedures for both cold and hot starts		Initial request.
B4	Normal Shutdown Operating Procedure		Initial request.
C	**Piping & Instrumentation Diagrams, Flow Diagrams**		
C1	Condensate System	[document reference info]	
C2	Feed water System	[document reference info]	
C3	Steam System (Main Steam, Cold Reheat, Hot Reheat)	[document reference info]	
C8	Air System (Primary, Secondary)	[document reference info]	Confirm latest revisions
C9	Flue Gas System	[document reference info]	Confirm latest revisions
C10	Fuel Supply System		Initial request.

Table 2 (continued)
Document/data requests for [Station Unit #]

Item Number	Description	Previously Supplied Information	Additional Request
D	**Control Logic Descriptions and Diagrams**		
D1	Feed water controls description		Initial request.
D2	Logic diagrams for feed water controls		Initial request.
D3	Furnace draft controls description		Initial request.
D4	Logic diagrams for furnace draft		Initial request.
D5	Superheat and reheat temperature controls description		Initial request.
D6	Logic diagrams for superheat/reheat controls		Initial request.
D7	Combustion controls description		Initial request.
D8	Logic diagrams for combustion controls		Initial request.
D9	Control system curves for excess O_2 (set-point versus load)		Initial request.
D10	Control system curves for over-fire air damper position versus load		Initial request.
E	**System Descriptions**		
E1	Boiler		Initial request.
E2	Condensate System		Initial request.
E3	Feed water System		Initial request.
E4	Steam System		Initial request.
E6	Steam Turbine System		Initial request.
E8	Air System, including Windbox		Initial request.
E9	Flue Gas System		Initial request.
E11	Fuel Supply System	[document reference info]	
E12	Coal Feeders	[document reference info]	

Table 2 (continued)
Document/data requests for [Station Unit #]

Item Number	Description	Previously Supplied Information	Additional Request
F	**Operating and Maintenance Manuals, Datasheets**		
F1	Boiler (datasheet and manual)	[document reference info]	Confirm latest revision
F2	Mills		Initial request.
F3	Burners		Initial request.
F4	Over-fire Air system		Initial request.
F5	Coal Feeders		Initial request.
F6	Primary Air Forced Draft Fans		Initial request.
F7	Secondary Air Forced Draft Fans		Initial request.
F8	Induced Draft Fans		Initial request.
F9	Booster Fans		Initial request.
F10	Steam Turbines		Initial request.
G	**Arrangement Drawings**		
G1	Boiler Elevation General Arrangement drawing	[document reference info]	
G2	Plot plan or site layout drawing		Initial request.
G3	HP/IP Turbine Cross-Section drawing		Initial request.
G4	LP Turbine Cross-Section drawing		Initial request.
G5	Boiler Flow Diagram	[document reference info]	Confirm latest revision
G6	Boiler Material Diagram (Tube/Header/Pipe Schedules and Materials)		Initial request.

Table 2 (continued)
Document/data requests for [Station Unit #]

Item Number	Description	Previously Supplied Information	Additional Request
H	**Heat and Mass Balance Diagrams**		
H1	Heat and Mass Balance- Full Load	[document reference info]	Confirm latest revision
H2	Heat and Mass Balance- Minimum Load		Initial request.
J	**Other**		
J1	Emissions limits in Air Permit		Initial request.

RFI for Key Loop Operating Data (Step 2)

Purpose: Identify process parameters and ramping periods for which to gather operating data.

Expected Content:

- Identification of data historian tags with process parameters of interest
- Types of operating periods for which to gather data (load bounds, types of ramps)
- Data sample frequency
- Questions on operating parameters
- Instructions for transferring data files to the team

See below for a template for an RFI for Key Loop Operating Data.

YYYY-MM-DD
[Document Number]

Unit Ramp Rate Optimization Methodology – [Station Unit #] – Request for Operating Data

1 Purpose

This Request for Information (RFI) identifies the operating data for the team to understand the current [Station Unit #] ramping characteristics. This RFI supplements the RFI issued by the team on YYYY-MM-DD (Reference 1).

2 Requests

Section 2.1 provides the team's request for operating data. Section 2.2 provides a list of questions to clarify the team's understanding of the tag names.

2.1 Operating Data

The team prepared an Excel workbook to accompany this RFI (*Workbook Name.xlsx*). This Excel workbook is based on a file provided by the plant. Notes regard the operating data request include the following:

Some tags are highlighted in yellow. The team inferred that these tags may be available based on ….

Some tags are highlighted in green. The team identified these tags using P&IDs and flow diagrams for the unit. The drawings used to identify these tags are referenced in the Excel workbook.

The team requests that:

1. Confirm and as necessary correct the tags highlighted in yellow.
2. Identify the PI tags highlighted in green.
3. Identify a representative ramping event for which to provide data. The event chosen should show the unit performance while ramping at the current highest possible rate. If there are examples of ramping operations that provide contrasting results (e.g., one with no problems and another with problems), choose two ramping events.
4. Obtain operating data for the requested points. The data should have a 15-second sample frequency and incorporate the following modes of operation:
   a. Steady state starting point for ramp (~10 minutes): Expected to be ~ ??? MW_{NET}.
   b. Load Increase Ramp.
   c. Steady state end point for ramp (~10 minutes): Expected to be ~ ??? MW_{NET}.
5. Place an Excel workbook with the requested operating data onto the network drive.

2.2 Clarification Questions

The team has the following questions concerning the tags:

1. [question 1]

2. [question 2]

3 References

1. *Unit Ramp Rate Optimization Methodology – [Station Unit #] – Request For Information*, [document number], YYYY-MM_DD.

Potential Improvements Table (Step 3)

Purpose: Document poorly controlled parameters and potential changes to improve control.

Expected Content:

- Process parameters that have unacceptable variation, and description of unacceptable variation
- Potential causes for the unacceptable variability
- Potential improvements

Ramp Rate Observation Plan (Step 3)

Purpose: Describe the elements of the planned ramp rate diagnosis testing.

Expected Content:

- Testing objectives
- Overall schedule
- Prerequisites to the testing
- Approach for each test run
- Operating adjustments and unit load profiles for each test run
- Key equipment and controls limits
- Data collection and sampling requirements

See below for an example table of contents for a Ramp Rate Observation Plan.

Table of Contents

Improvement Recommendation Table (Step 4)

Purpose: Document recommended changes to improve the unit ramp rate.

Expected Content:

- Current ramp rate (from Project Charter)
- Desired improvement in ramp rate (from Project Charter)
- Identified limits on unit ramp rate (from Potential Improvements Table and ramping observations)
- Recommended changes to improve ramp rate, with sufficient conceptual description to charter a plan to implement the improvement (Step 5)
- Limits for which changes were not identified, or for which potential changes were considered and rejected

Implementation Plan (Step 5)

Purpose: Identify the changes that will be made to improve ramp rate and plan the implementation of these changes.

Expected Content:

- Identification of changes to implement permanently (not necessarily every change identified in Step 4)
- Sufficient scope description for each change to guide implementation team
- Identification of implementation team for each change
- Schedule, estimated team effort, and estimated expenses for each change
- Identification of data that will be gathered to assess the effectiveness of each change
- Acceptance criteria that change has achieved desired outcome
- When multiple changes are identified, plan for order in which the changes will be made
- Plan for staged implementation, if appropriate (e.g., controls change will be implemented in advisory mode before implementation in automatic controls)
- Approval from all the stakeholders on plan

B
COAL-FIRED SUPERCRITICAL UNIT CASE STUDY

The findings from a case study performed to improve the ramp rate of a coal-fired supercritical steam generating unit are discussed in this appendix. The unit included in this case study illustrates typical ramping issues encountered on this type of steam generating unit. The discussion covers general technical guidance on the evaluation of unit ramp rate limits and details from the diagnosis testing to identify ramp rate limitations on a specific unit. A list of references specific to increasing the ramp rate of a coal-fired supercritical steam generating unit is also provided.

Technical Guidance

The technical guidance provided in this section is focused on the control arrangements applied to coal-fired supercritical generating units. The technical guidance highlights specific areas of evaluation most applicable to improving the unit ramp rate on these types of units. Explanations the impacts of these diverse areas on the unit ramp rate and approaches for evaluating unit ramping conditions are provided. This discussion uses terminology consistent with that presented in Sections 3 and 4 of this report.

Key Control Loops

The key control loops affecting ramp rate need to be identified early in an optimization ramp rate project (e.g., Step 1 in this methodology). Figure B-1 illustrates typical high-level hierarchy of controls for a coal-fired supercritical steam generating unit. The controls design for a specific unit may differ from that shown in the figure. It is common for the ramp rate of these units to be managed by the seven key control loops illustrated in Figure B-1.

Additional control loops, beyond those illustrated in Figure B-1, may exist in a coal-fired supercritical steam generating unit that influence its ramp rate. Where one of these loops is concluded to be key to the ramp rate of a specific unit design, the reader should develop a similar understanding of the control loop to those documented in Table B-1 through Table B-6 for the key control loops. These tables provide a brief description of the function of the control loop and identify process parameters affected by the control loop.

This technical guidance is intended to support the user's analysis of the control logic for each of these control loops. The parameters identified in each table should be considered in the operating data reviews included in the ramp rate improvement methodology.

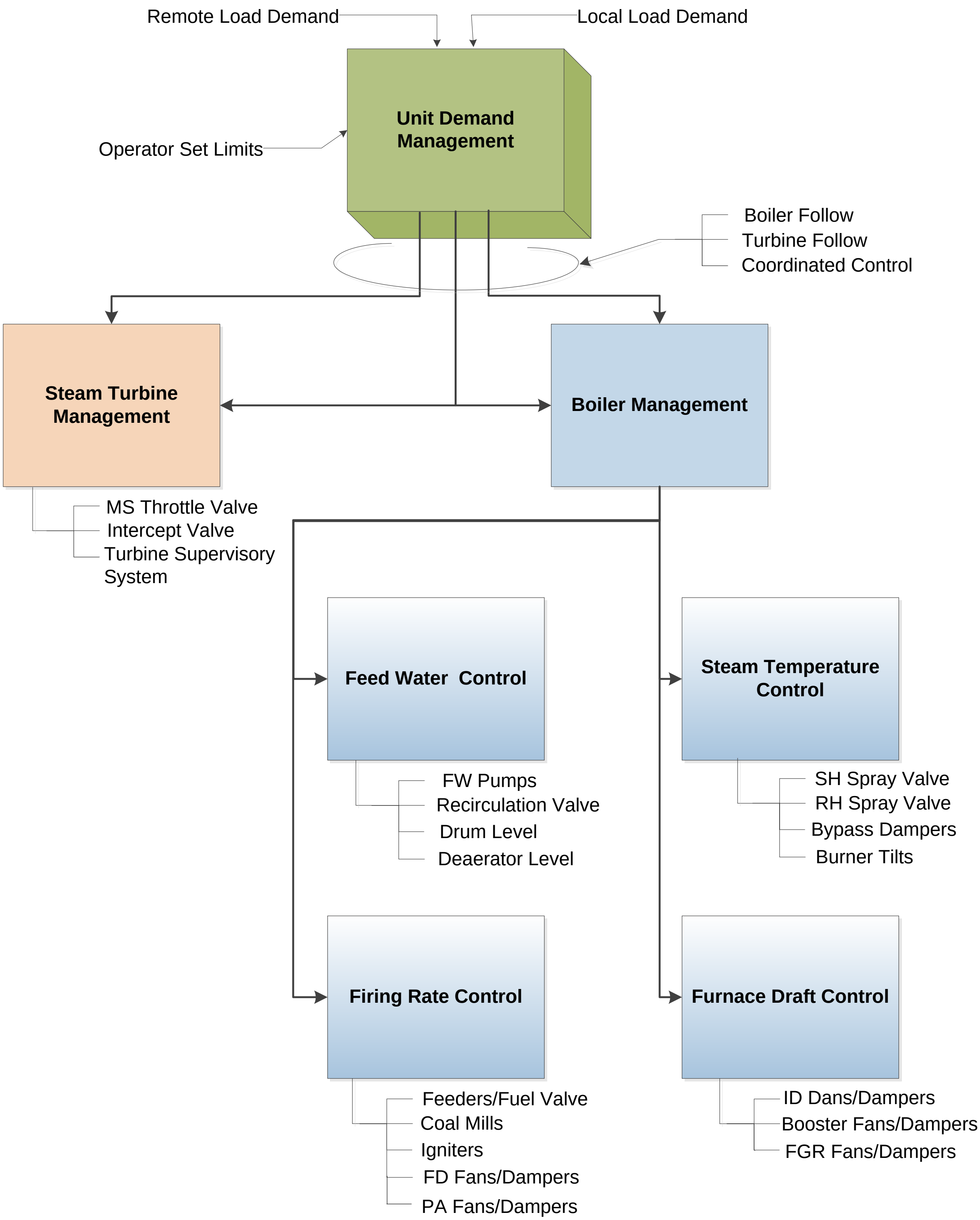

Figure B-1
Key control loops – Coal-fired supercritical units

Unit Demand Management Controls

The unit demand management controls provide load demand signals for the boiler and the steam turbine. Typically, this is the level at which load ramping demands are provided, whether by control room operator input or signals from remotely located transmission system operators.

There are generally three modes of unit demand management control: boiler follow, turbine follow, and coordinated mode. The selected mode can greatly affect the ramp rate.

- Boiler follow provides for potentially the fastest ramps, but most variability in main steam conditions.
- Turbine follow maintains the most stable steam conditions, but at the expense of ramp rate.
- Coordinated control mode offers the potential best compromise in ramp rate and control stability.

Table B-1
Unit demand management control loop

Description	Key Parameters
Manages demand on the boiler and steam turbine generator.	• Unit Master Load Demand • Selected Control Mode • Unit Power (MW_{GROSS} and MW_{NET}) • System Frequency • Ramp Rate Limit • Boiler Master Signal • Turbine Master Signal • Unit Frequency Correction Signal

Boiler Controls

The boiler controls include four control loops governed as part of the boiler management system. Each of these control loops directs a critical function in the production of steam by the boiler system. The parameters listed are typical of coal-fired supercritical boiler designs.

Table B-2
Furnace draft control loop

Description	Key Parameters
Directs air and flue gas flows through the unit to maintain combustion, heat transfer, and backend emissions control conditions. Where over-fire air and/or flue gas recirculation is used, the control loop may also be involved in direct control of NO_X emissions.	• Furnace Pressure • Feedforward Signal from Air Flow Demand • Backend Flue Gas Pressure • ID Fan Speed • ID Fan Inlet Damper Position • Booster Fan Speed • Booster Fan Inlet Damper Position

The Furnace Draft Control loop often uses one ID Fan as the lead for furnace pressure control adjustments and the second ID Fan as the lead for total air flow adjustment. The mechanical response of the dampers and/or drives often determines the degree of control achieved.

Table B-3
Steam temperature control loop

Description	Key Parameters
Provides control of SH and RH steam temperatures through control of spray water addition to steam. Where burner tilts or back pass dampers are provided, the control loop may also use these systems as alternative controls of RH steam temperatures.	• Steam Temperature Master Signal • SH Outlet Temperature • RH Outlet Temperature • SH Attemperator Spray Valve Position • SH Attemperation Spray Flow • RH Attemperator Spray Valve Position • RH Attemperation Spray Flow • Burner Tilt Angle • Back Pass Damper Position

The mechanical response and minimum flow adjustment of the spray valve often determines the degree of steam temperature control achieved.

Table B-4
Firing rate control loop

Description	Key Parameters
Feeds fuel and air to the furnace to set combustion rate, distribution of fuel in the furnace, and rate of steam generation. Works with burner management system to ensure safe initiation and removal of burners from service.	• Firing Rate Master Signal • Steam Temperature Correction Signal • Fuel Master Signal • Air Flow Cross Limit on Fuel Demand • Total Fuel Flow • Feeder Speed • Windbox Pressure • O_2 Set Point and O_2 Trim • Exit Flue Gas O_2 • Secondary Air Demand • Air Master Signal • FD Fan Damper Position • Secondary Air Damper Position • Over-fire Air Damper Position • Primary Air Damper Position • Mill Exit Coal/Air Temperature • Cold Air Damper Position • Mill Motor Current • Mill Start • Flame Indication • Burner Isolation Gate Valve Position

Operator actions involved in establishing conditions for mill operation and burner ignition sometimes control the rate of unit load changes and are often features outside of the firing rate control loop.

Table B-5
Feed water control loop

Description	Key Parameters
Directs feed water flows through the unit to maintain heat transfer and control rate of steam generation. Includes level control for steam drum and deaerator. Methods for feed water flow may include pump speed and recirculation.	• Control Mode • Steam Flow • Feed Water Flow • Feed water Pressure • Steam Drum Level • Deaerator Level • Feed Water Control Valve Position • Boiler Feed Pump Speed • Feed Water Recirculation Valve Position • Feed Water Control Valve Position • Condensate Valve Position • Condensate Pump Speed

Feed water flow control frequently has at least two modes of operation to address start up/low load and higher load operation (e.g., single element control and three element control). Changes in feed water control mode can affect ramping. Operator actions involved in transfer from single to multiple feed water pump operation sometimes controls the rate of unit load change and are often features outside of the feed water control loop.

Steam Turbine Management Controls

The steam turbine management controls focus on positioning the turbine inlet valves.

Table B-6
Steam turbine control loop

Description	Key Parameters
Maintains pressure control of steam flow to steam turbine and matches steam flow to load demand on generator.	• Turbine Speed • Main Steam Temperature • Main Steam Pressure • Hot Reheat Temperature • Hot Reheat Pressure • 1st Stage Pressure • Control Valve Admission Mode • Main Steam Control Valve Position • Turbine Differential Expansion

Vendor Limits Incorporated in Controls

The limits on process parameters affected by the key control loops are most often initially based on vendor-identified limits for components or systems. Table B-7 identifies the significant limits that should be identified for the specific unit whose ramp rate will be improved. The basis for the limit also should be examined to identify where margin may be available that can improve the unit ramp rate. Table B-7 provides a generic description of the normal basis for concern regarding the vendor imposed limits.

Table B-7
Vendor imposed limits

Vendor	Parameter	Typical Basis of Concern
Boiler	Superheater Steam Temperature	Steam temperatures exceed long-term operating limits of tube, header or interconnecting piping materials. Spray flow swings impose temperature cycles on interconnecting piping, header and tube stresses.
	Reheater Steam Temperature	Steam temperatures exceed long term operating limits of tube, header or interconnecting piping materials. Spray flow swings impose temperature cycles on interconnecting piping, header and tube stresses.
	Reheater Steam Pressure	Pressure fluctuations decrease life of headers and interconnecting piping.
Furnace	Minimum Exit O_2	Insufficient airflow can be mismatched to fuel flow, leading to loss of stable combustion.
	Maximum Furnace Pressure	Insufficient ID fan capacity loads to high furnace pressures
Steam Turbine	Rotor Expansion	Steam temperature transients.
	Exhaust Hood Temperature	Changing pressure conditions during transient load conditions impact exhaust temperatures
Air Emissions Permit	NO_X	Limited on reaction at lower flue gas conditions Mismatch of combustion air distribution during transient load conditions
	NH_3	Burn off of deposits on catalyst can result in excursions. Improper control of ammonia addition during transient load conditions.
	Opacity	Changing flue gas temperature impacts control achieved Accumulated deposits may adversely affect particulate matter collection

Mitigation Actions for Ramp Rate Limitations

Ramp rate improvement depends on the diagnosis of the individual factors limiting the rate of generation increase and implementing control changes to mitigate those limitations. Each factor must be identified separately, typically through observation of a unit load ramp. Therefore, mitigation of each limits, by either control logic, operator process, or equipment modification, must be implemented individually before the next limiting factor can be identified.

The sequential nature of ramp rate limitation diagnosis requires that mitigating approaches be available for each limit. Table B-8 through Table B-13 provide guidance on mitigating approaches to consider for ramp rate limitations with the most potential impact at coal-fired generating units. These mitigating approaches are discussed in relation to the control loop in which the potential ramp rate limitation could occur. The mitigating approaches focus on changes that can be implemented without permanent reprograming of the DCS logic.

Table B-8
Mitigation approaches to unit demand management related limits

	Potential Ramp Rate Limitation	Mitigation Approach
1	Control logic does not implement ramp rate inputs	Evaluate each operating mode to evaluate impact of ramp rate input on unit behavior.
2	Turbine follow operation does not allow sufficient ramp rate flexibility	Identify an alternative operating mode that implements more rapid ramp rate response.
3	System voltage regulation feedback limits ramp rate	Expand system voltage lag permitted during ramping until 90% load is achieved.

Table B-9
Mitigation approaches to steam temperature control related limits

	Potential Ramp Rate Limitation	Mitigation Approach
1	SH tube metal temperatures exceed alarm limits	Add a counter to the alarm to account for the short term nature of the high temperature alarm.
2	SH tube metal temperatures exceed alarm limits	Maximize the furnace waterwall heat absorption during the ramp by: • Sootblowing the furnace waterwalls prior to the start of the ramp. • Bias the demand on the lower mills higher until approach full load. • Bias the burner tilt angle lower until approach full load.
3	SH-RH temperature differential exceeds vendor recommendations	Increase RH heat transfer during the ramp by: • Isolating RH attemperator(s) to minimize leakage until unit reaches full load. • Bias down the cold RH extraction flow until unit reaches full load. • Bias up or control manually furnace flue gas recirculation until unit reaches full load.

Table B-10
Mitigation approaches to firing rate control related limits

	Potential Ramp Rate Limitation	Mitigation Approach
1	Air preheater temperature increase does not satisfy mill operating conditions	Use steam air heaters to increase inlet temperature of air to the air preheater
2	Forced draft fan response	Bias flow control for forced draft fans to increase response until ramp is complete.
3	Windbox pressure stability	Bias flow control for the forced draft fan responsible for controlling windbox pressure until all mill are in-service.
4	Primary air minimum flow	Manually control primary air fan to maintain coal pipe flow above critical velocity until 50% load achieved.
5	Fuel flow rate of change exceeds the existing exit flue gas O_2 rate of change	Bias the O_2 control to decrease the set point curve and remove bias after unit load ramp is complete.
6	Flame proving for mills slows ramp rate.	Initiate operation of all igniters as first step of ramp load increase and prior to raising load on operating mill(s). Secure igniters after coal firing is proven as each mill required for full load is placed in operation.
7	Mill start-up interlocks slow ramp rate.	Start mills with “no coal flow” prior to initiation of ramping.
8	Excessive time delay programmed in flame proving system	Update the local interlocks in flame proving device to reduce flame stability assessment delays.

Table B-11
Mitigation approaches to feed water control related limits

	Potential Ramp Rate Limitation	Mitigation Approach
1	Time to start second boiler feed pump limits ramp rate.	Prior to the start of ramping, start second boiler feed pump and maintain in stand-by using recirculation system to speed transition to multiple pump operation.
2	Unstable feed water flow control during low load portion of ramp	Manually open the recirculation system to increase the operating point of the feed water control valve. Return to automatic operation when feed water demand exceeds 30 percent.
3	Unstable drum level control	Remove bias on feed water pressure as first mill approaches full fuel flow to engage multi-element control.

Table B-12
Mitigation approaches to furnace draft control related limits

	Potential Ramp Rate Limitation	Mitigation Approach
1	Induced draft fan response	Bias furnace pressure set point to increase response until all mills are in-service.

Table B-13
Mitigation approaches to steam turbine control related limits

	Potential Ramp Rate Limitation	Mitigation Approach
1	Steam flow utilization limits turbine ramp rate	• Close any by-pass or drain valves opened to support minimum load operation at the start of ramping. • Restrict use steam sootblowing system during ramping. • Maximize operation on motor driven boiler feed pump during ramping. • Bias control valve(s) on extractions during ramping.
2	Steam flow production limits turbine ramp rate	Bias steam temperature control lower to maximize the steam flow to turbine and restore after all mills are in service.

The mitigating approaches identified in the tables above may impact other areas of the unit operation during ramping. The specific mitigating action(s) and the extent of the change applied will vary based on the specific unit design. A unit specific balance among mitigating approaches will need to be developed as part of the ramp rate improvement process.

The mitigating approaches discussed in this section are not intended to cover all potential ramp rate limitations. They provide a reference for the most typical mitigation actions for coal-fired power plants.

Pilot Implementation of Ramp Rate Diagnosis

Development of the Unit Ramp Rate Optimization methodology included a limited-scope pilot implementation at a coal-fired steam generating unit. This section provides the findings from the ramp rate diagnosis testing (Methodology Step 4). Discussion is focused on illustrating the improvements identified during the pilot testing.

The pilot implementation efforts did not attempt to complete the optimization of the ramp rate(s) on the host unit. Further work is necessary to fully develop the ramp rate potential of the host unit.

Background

The host utility for the pilot implementation was concerned with improving the ramp rate of their coal-fired steam generating unit to replace the system load response previously handled by simple cycle combustion turbines being removed from their control. The current unit capabilities, as defined in Figure 1-1, were:

Nominal Ramp Rate	3 MW/minute
Approach Ramp Rate	1 MW/minute

No specific targets were identified for the improvement required to enable the coal-fired generating unit to satisfy the anticipated system load response requirements.

Unit Background

The pilot implementation testing was hosted by a three-unit coal-fired steam generating power plant. Each unit, rated for 684 MWe, is equipped with wet flue gas desulphurization (WFGD), selective catalytic reduction (SCR), and electrostatic precipitators (ESPs) for air emissions controls.

The pilot testing was performed on a single unit of the generating station whose control logic was recently upgraded. No work had been performed by the generating station prior to the pilot test to improve the unit ramp rate.

Test Runs

Diagnosis testing was performed to identify improvements in the ramp rates of the test unit. Fan capacity was a known limitation on the approach ramp rate prior to the start of the testing.

Figure B-2 illustrates the unit load behavior during each of the tests to diagnose the limits on unit ramping. In two of the tests (A&C), different ramp rates were observed during different periods of the unit ramping. These different ramp rates corresponded to load ranges in which mills and burners were started (lower loads) and load ranges without these loads (higher loads).

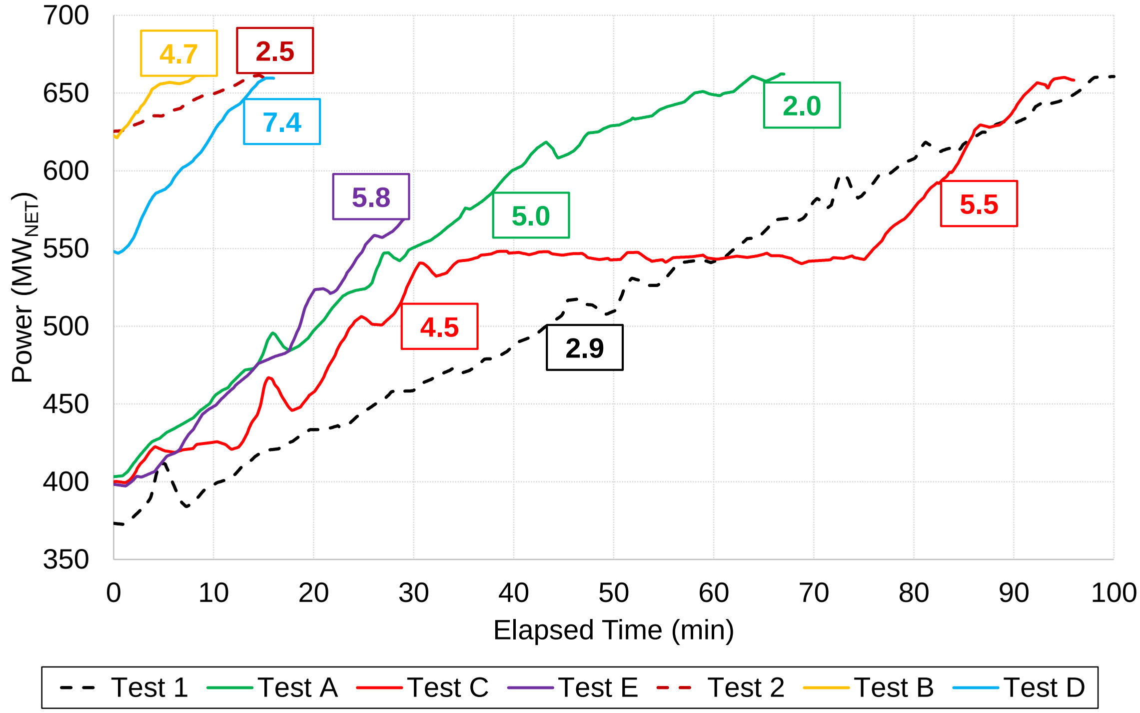

Figure B-2
Ramp rate diagnosis pilot tests

Table B-14 summarizes the unit ramp rates observed. The test results are presented in order by ramp type. The test numbering indicates the sequence of the testing. The numbered tests were to observe baseline operation. The lettered tests implemented changes derived from the initial diagnosis and then refined in subsequent tests.

Table B-14
Pilot test improvements

Test	Ramp Rate (MW/min)	Change from Existing Nominal Rate
Ramp Type: With Mill Starts		
1	2.9	-3%
A	5.0	67%
C	4.5	50%
E	5.8	93%
Ramp Type: Without Mill Starts		
2	2.5	17%
A	2.0	13%
B	4.7	57%
C	5.5	88%
D	7.4	47%

The substantial improvements in the ramp rates reflect the extent of the conservatism in the existing unit ramping approach.

Findings

The opportunities identified during the pilot testing to improve the unit controls are summarized in this section. The opportunities developed for the test unit were limited by the duration and pilot focus of the tests but are considered representative of specific areas for change at other coal-fired steam generating units to improve their ramp rates.

Superheat Temperature Control Improvement

Initiating operation of burner pairs during load ramping was identified as challenging the superheat temperature control during baseline ramping. As each pair of burners started, excursions were observed in the superheater temperature. As shown in Figure B-3, the magnitude of the temperature excursions were small, but operations personnel viewed this behavior as limiting with regard to further increasing the unit ramp rate.

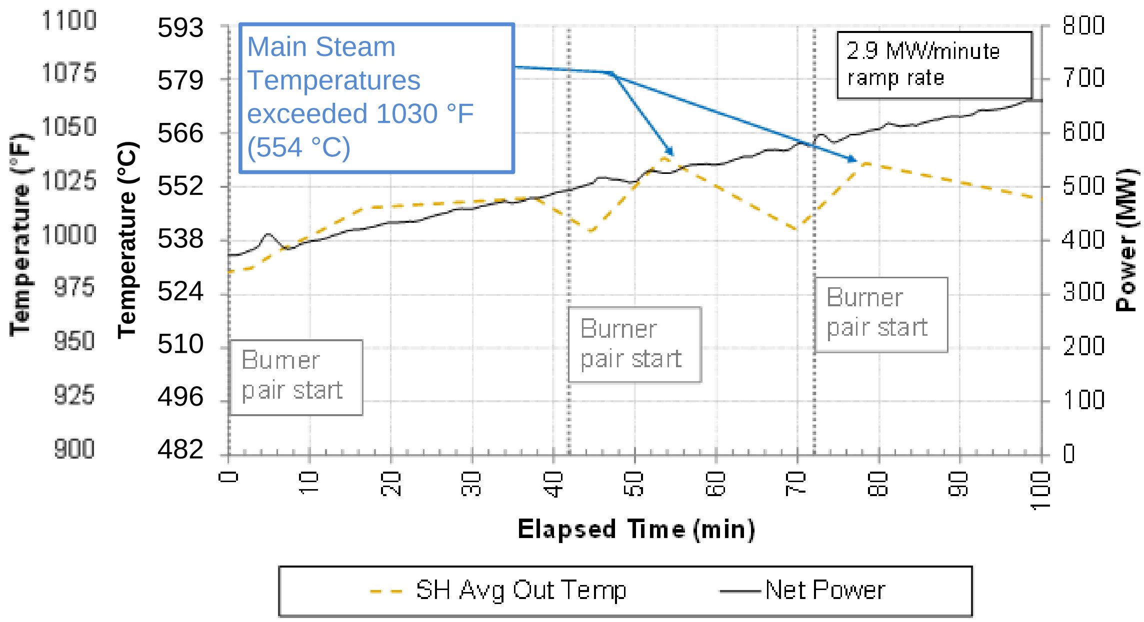

Figure B-3
Superheater temperature excursions during ramping

Manual changes in the distribution of the air flow as the burners were started were implemented to eliminate the spike in heat input to the furnace observed in the baseline operation. These changes involved manual manipulation of both the capacity and auxiliary air dampers on the mills and the on the furnace. Figure B-4 illustrates the implementation of these changes in the operation of the burners. These changes eliminated the superheat temperature excursions and allowed an increase in the unit ramp rate.

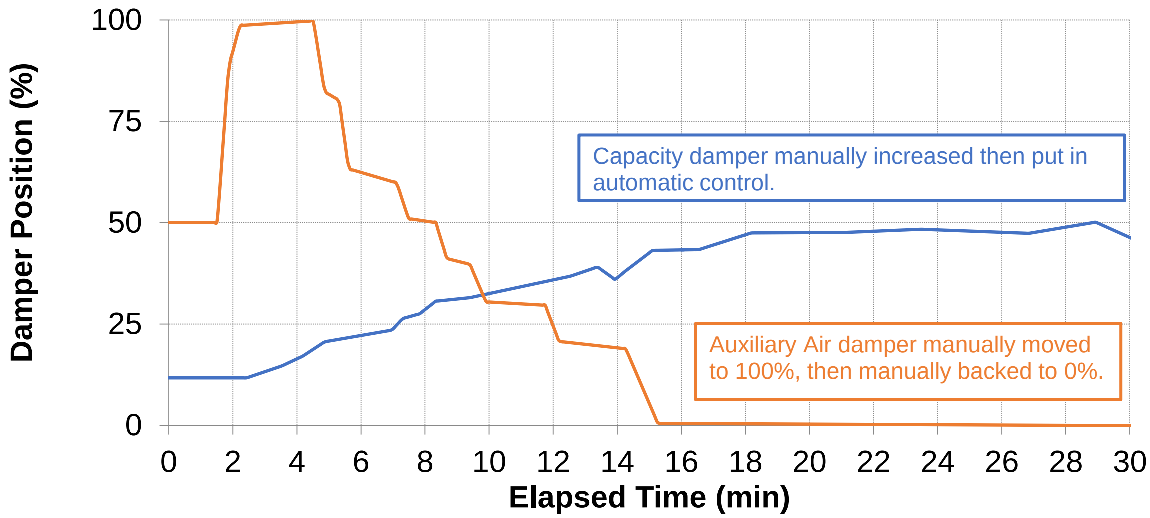

Figure B-4
Burner operation changes to improve superheat control

During the testing, these changes were implemented manually. Revision of the burner control logic is recommended to allow automatic operation to support the increased ramping rate.

A further challenge with the control of superheater temperatures was observed during the baseline ramp rate testing as illustrated in Figure B-5. Significant temperature excursions occurred once the superheater spray valve demand reached fully open.

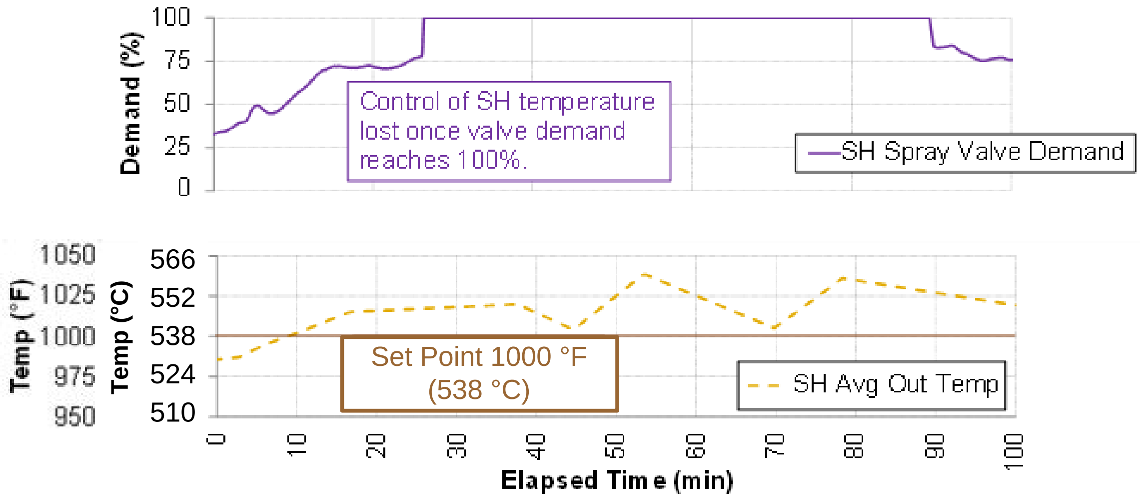

Figure B-5
Superheater spray control during ramping

Reductions in the steam temperature master set point were implemented as each burner pair was started. Modest reductions in the set point significantly reduced the demand for superheater spray flow. As shown in Figure B-6, the reduction in superheater spray demand allowed substantial improvement in the control maintained at the higher loads.

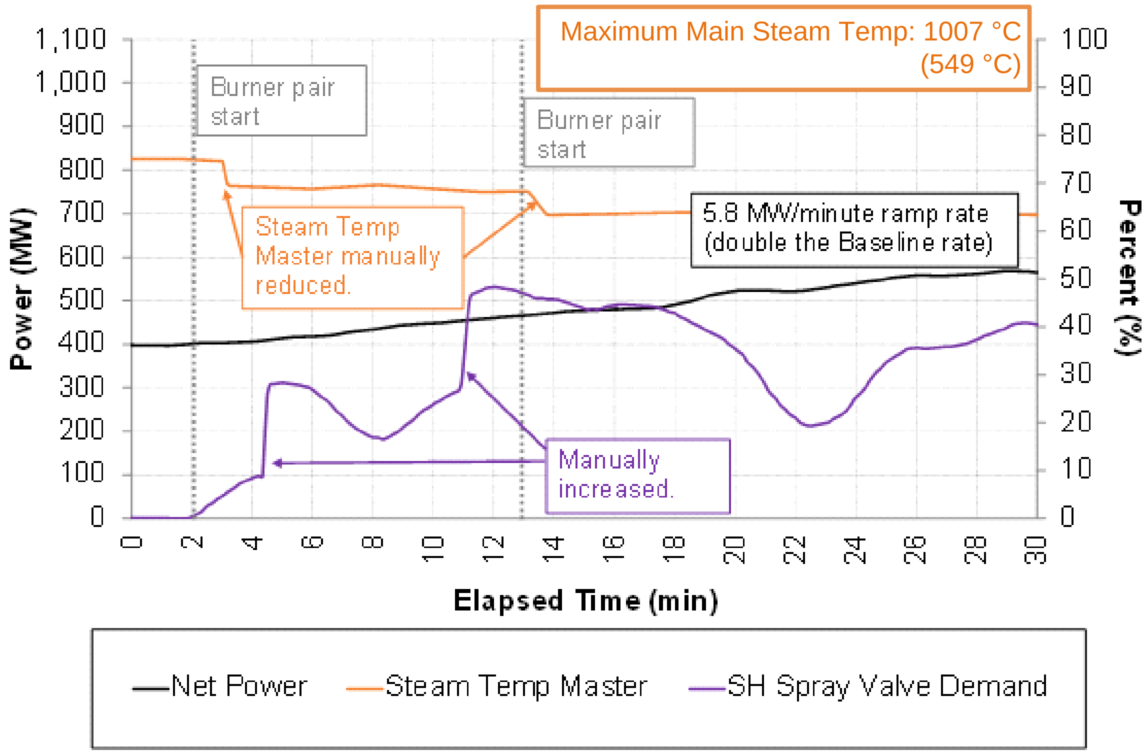

Figure B-6
Steam temperature control changes to reduce excursions

During the pilot testing, these changes were implemented manually by biasing the set point. Implementation of this improvement would involve changing the control logic to match the developed steam temperature master signal.

Reheat Temperature Control Improvement

Changes in the behavior of the reheat temperature master were determined necessary to maintain reheat temperature control during ramping. Figure B-7 shows the baseline behavior where the installed logic slowly increased the reheat temperature master during the unit ramping. This resulted in reheat temperatures exceeding the 1005°F (541ºC) design point on both sides of the boiler, and with a high temperature of 1030°F (554ºC) on one side of the boiler.

Improvement in the reheat temperature control was achieved by manually adjusting the reheat temperature master, as shown in Figure B-8. These changes limited the reheat temperature excursion on one side of the boiler to less than 1020°F (549ºC) and the average of both sides to within the reheat temperature design point. The ramp rate was doubled under this change in control approach.

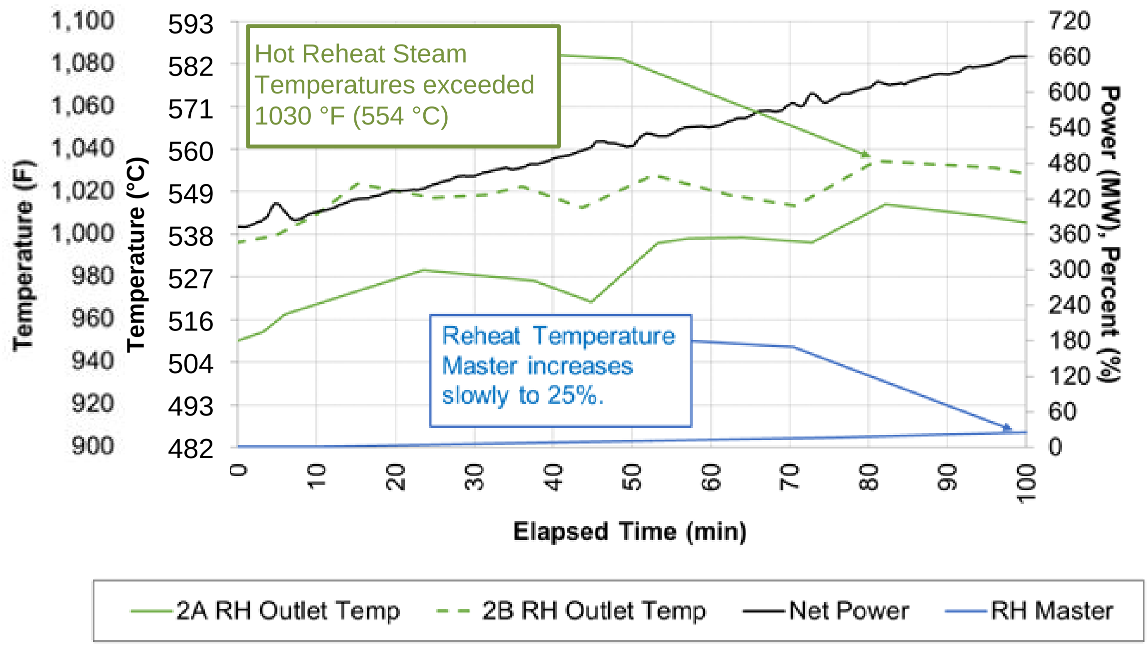

Figure B-7
Reheat temperature excursions during ramping

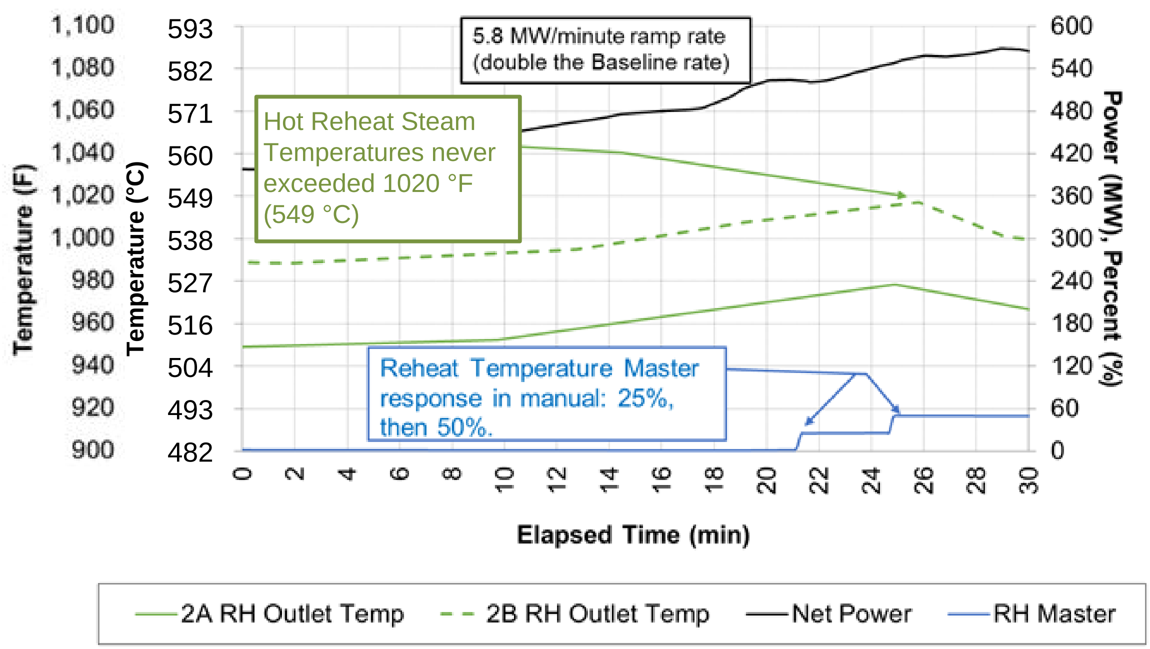

Figure B-8
Reheat temperature control changes to reduce excursions

Further refinement of the changed approach for the reheat temperature master set point is required to finalize the method to implement in the control logic.

Fan Control Improvement

Control of the excess O_2 was diagnosed as another limit to increasing the nominal ramp rate. Under the existing forced draft fan master, the excess O_2 was reduced at an increased ramp rate to the limits of the burner management system protection logic. As shown in Figure B-9, this resulted in the control system halting the unit load ramp when the fuel input was automatically run-back to improve the combustion conditions.

It should be noted that this occurred while operating in coordinated control mode. The unit ramp rate was limited based on a signal for low turbine throttle pressure. In diagnosis of the event, the operating event was traced back to insufficient excess O_2 and its influence on firing.

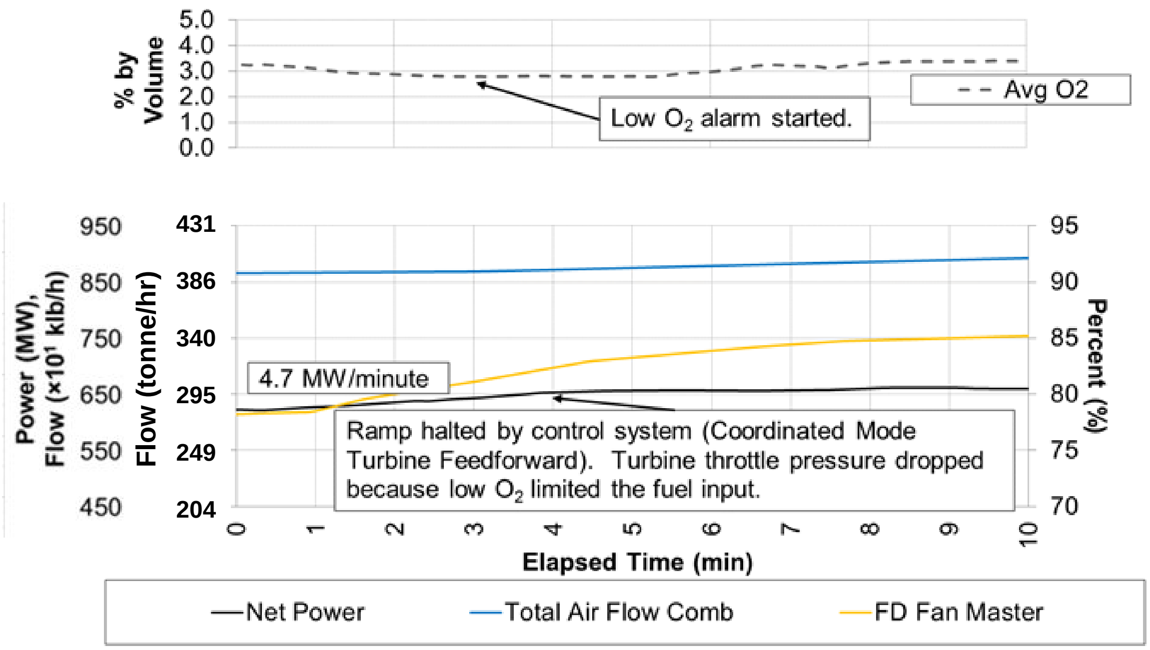

Figure B-9
Excess O_2 limits on ramping

Improvement in the unit ramp rate required a change in the unit control to maintain the excess O_2 value above the low alarm set point (2.8%). The rate of change of the FD fan master was doubled to maintain the excess O_2 during the unit ramping. This manual bias of the FD fan master significantly increased the unit ramp rate while maintaining significant margin in the excess O_2. Figure B-10 shows the impact of the FD fan master bias change on the approach ramp rate and the excess O_2.

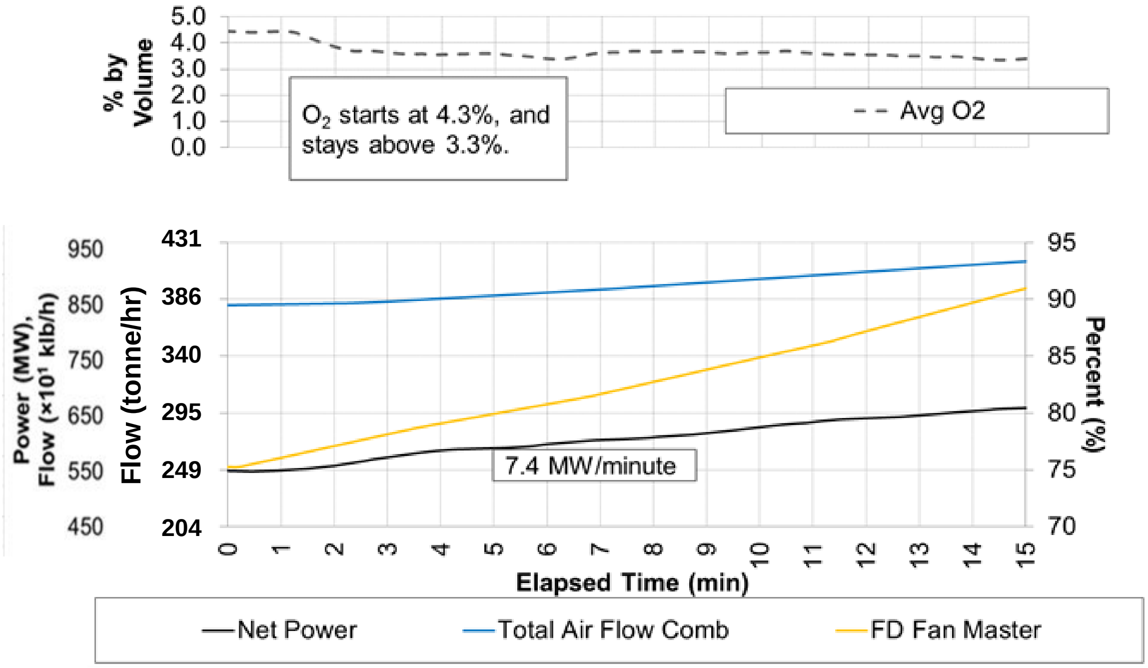

Figure B-10
Forced draft fan control changes to improve excess O_2 control

This change is an example of incomplete tuning of the controls for unit ramping near full load. The approach implemented in the controls prevents a low excess O_2 condition that was not tuned to optimize ramp rate stability. Under the expected system operations, this improvement in unit capability for ramping has greater value to the unit operator than at the time of the control commissioning.

Equipment Alignment for Improved Ramp Rate

In addition to the control changes identified during the pilot testing, several other operational adjustments were recognized as key to increasing the unit ramp rates. These changes were achieved through manual adjustments:

1. Minimize the superheat spray flow at the beginning of the load ramp. This adjustment ensured sufficient range of flow adjustment was available during the load ramp.
2. Maintain the SCR temperatures at low load by increasing the bias on the excess O_2 trim. A second low load operation adjustment involved suspending furnace sootblowing at low load. Finally, the minimum load operating configuration used the upper mills to the extent possible. These three adjustments to the equipment operation contributed to maintaining the flue gas temperatures to the SCR during unit load ramping.
3. Keep as many burners in-service at minimum load as possible to achieve the highest ramping rates. The operator actions required for starting mills or placing burners in-service slow the ramping. Mills should only be taken out-of-service when necessary to maintain minimum load for extended periods (e.g., overnight).

The starting equipment alignment for the load ramp has a significant effect on the ramp rate that can be achieved.

Recommendations

The pilot test results identified control modifications that would improve ramping operations, and the need for further testing. These two areas of recommendations are discussed below.

Control Modifications

The pilot testing identified the following control modifications that would improve ramping operations:

- Update the mill controls to provide balanced heat input between the operating mills;
- Automate the steps identified for burner starts to minimize heat input spikes;
- Revise the superheater control settings to improve steady state temperature control;
- Improve the response rate of the following controls:
  - Steam temperature trim on firing rate;
  - Superheater spray flow;
  - Pass dampers for reheat temperature control; and
  - Excess O_2.
- Increase the gain on the ramp rate feedback to better match operator selected ramp rate with achieved unit ramp rate.

During the pilot tests, two operators were required to achieve the best ramp rates while placing burners in service. The control logic improvements on burner starts would reduce the required operator attention to the burners during ramping and allow continued operation by one operator.

Implementation of the control modifications should be followed by additional testing to demonstrate the suitability of the changes and any potential for further improvement. Each control change should be implemented separately to ensure that the overall effects on unit operation are evident. The stability of the control changes should be demonstrated, as well as their effectiveness in supporting an increased unit ramping rate. This type of implementation would be consistent with Steps 6 and 7 of the methodology presented in this report.

Additional Testing

The ramp rates observed during the pilot test were associated with nominal type load ramping. Higher ramp rates are feasible for nominal ramping and approach ramping. Further testing was recommended to evaluate the following ramp rates:

Nominal ramping	> 6 MW/min with burner starts
	> 8 MW/min without burner starts
Approach ramping	> 2 MW/min

The pilot testing was only performed with the unit operating in the one control mode (i.e., of the options generally thought of as boiler follow, turbine follow, and coordinated control, only one specific implementation of coordinated control was tested). The impact of other available control modes on the unit ramp rate should also be tested.

Case Study References

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C
NATURAL GAS-FIRED COMBINED-CYCLE UNIT CASE STUDY

The findings from a case study performed to improve the ramp rate of a natural gas-fired combined cycle unit are discussed in this appendix. The 2×1 unit included in this case study illustrates typical ramping issues encountered on a combined cycle unit. The discussion covers general technical guidance on the evaluation of unit ramp rate limits and details from the diagnosis testing to identify ramp rate limitations on a specific unit. A list of references specific to increasing the ramp rate of a natural gas-fired combined cycle unit is also provided.

Technical Guidance

The technical guidance provided in this section of the report is focused on the control arrangements applied to combined cycle units and highlights specific areas of evaluation most applicable to improving these units' ramp rates. Explanations of the controls' impacts on the unit ramp rate and approaches for evaluating unit ramping conditions are provided. This discussion uses terminology consistent with that presented in Sections 3 and 4 of the report.

Key Control Loops

The key control loops affecting ramp rate need to be identified early in a ramp rate optimization project (for example, Step 1 in this methodology). Figure C-1 illustrates a typical high-level hierarchy of controls for a natural gas-fired combined cycle unit. Although the controls design for a specific unit may differ from Figure C-1, it is common for the ramp rate to be managed by the seven key control loops illustrated.

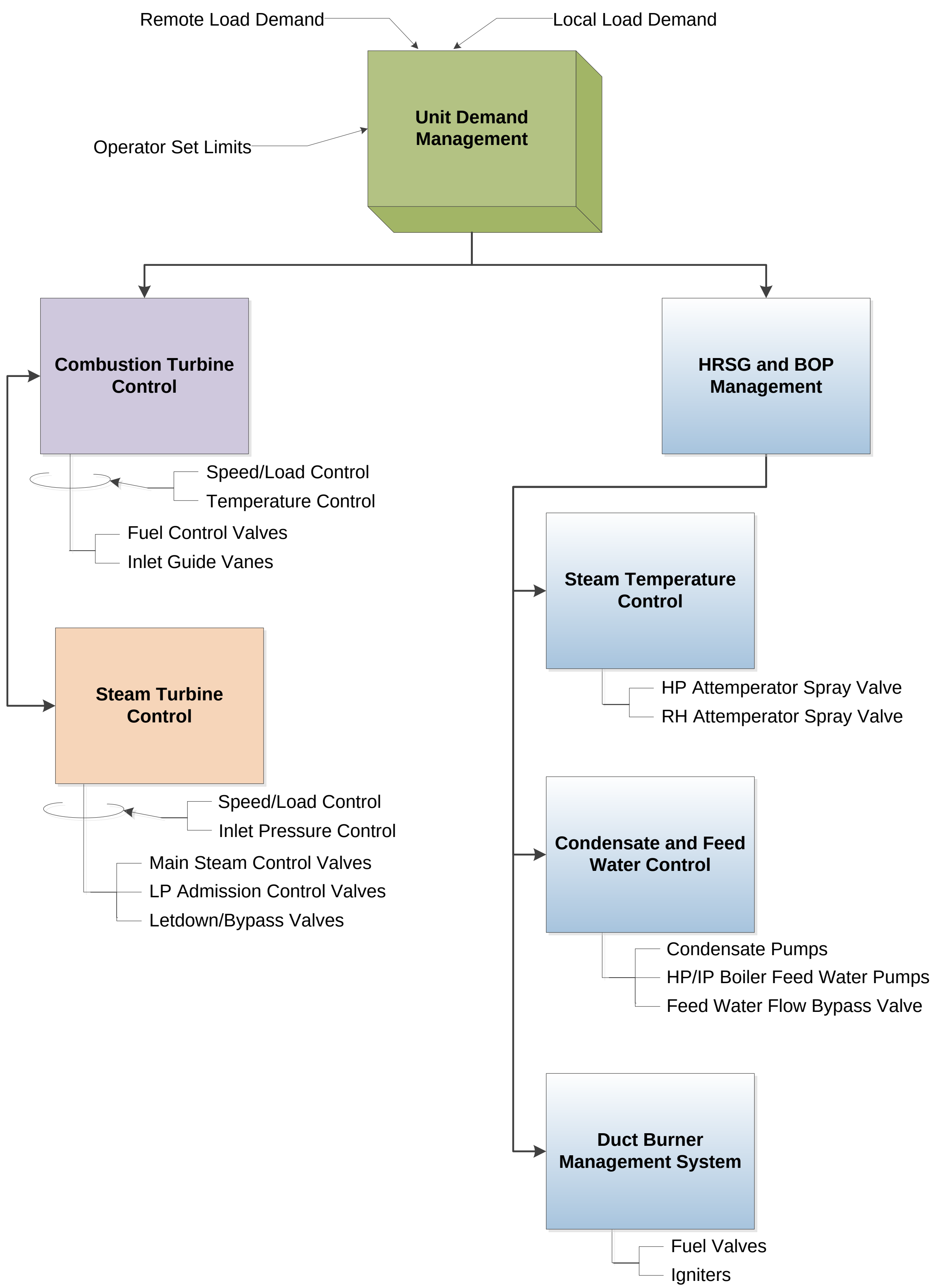

Figure C-1
Key control loops for a combined-cycle unit

Additional control loops, beyond those illustrated in Figure C-1, may exist in a natural gas-fired combined-cycle unit that influence its ramp rate. Where one of these loops is determined to be key to the ramp rate of a specific unit design, the user should develop a similar understanding of the control loop to those documented in Table C-1 through Table C-6. These tables provide a brief description of the function of the control loop and identify process parameters affected by the control loop.

This technical guidance is intended to support the user's analysis of the control logic for each of these control loops. The parameters identified in each table should be considered in the operating data reviews performed as part of the ramp rate improvement methodology.

Unit Demand Management Controls

The unit demand management controls typically provide load demand signals for the combustion turbines. The load ramping demand can be provided by either control room operator input or signals from remotely located transmission system operators.

Table C-1
Unit demand management control loop

Description	Key Parameters
Manages demand on the combustion turbine generators	• Unit master load demand • Unit load (MWGROSS and MWNET) • Number of combustion turbines in service • System frequency • Unit frequency correction signal

Combustion Turbine Management Controls

The combustion turbine management controls focus on positioning the combustion turbine fuel control valves and inlet guide vanes. Three control modes are typically provided that address the fuel control valve demand signal: startup control, speed/load control, and temperature control. Speed/load control is typically the active control mode when ramping within the normal load range for the combustion turbine.

Table C-2
Combustion turbine control loop

Description	Key Parameters
Manages fuel demand signal, during startup and shutdown operations, to meet speed/load demand and protect the turbine components from excessive temperatures	• Turbine speed • Load demand • Generator load • Allowable ramp rate • Fuel control valve position • Fuel flow • Compressor discharge pressure • Turbine exhaust temperature • Inlet guide vane position

Steam Turbine Management Controls

The steam turbine management controls focus on positioning the turbine control valves. These valves can be controlled for speed/load control or inlet pressure control. When inlet pressure control is used, which is typical in the load range of interest for ramping optimization, the steam turbine load is a function of the heat recovery steam generator (HRSG) steam production and is not directly controlled by the steam turbine.

Table C-3
Steam turbine control loop

Description	Key Parameters
Maintains pressure control of HP and LP steam systems and, in some cases, matches steam flow to load demand on the generator.	• Turbine speed • Generator load • Allowable ramp rate • First stage pressure • HP steam pressure • LP steam pressure • Main steam control valve position • LP turbine admission control valve position

HP = high pressure; LP = low pressure.

Steam Temperature Controls

The superheater (SH) and reheater (RH) temperature controls are provided through the use of spray attemperation stations. The spray flows are typically controlled based on the attemperator outlet temperatures and the final SH and RH outlet temperatures.

Table C-4
Steam temperature control loop

Description	Key Parameters
Provides control of SH and RH steam temperatures through spray water in addition to steam	• SH outlet temperature • SH attemperator spray valve position • SH attemperation spray flow • SH attemperator outlet temperature • RH outlet temperature • RH attemperator spray valve position • RH attemperation spray flow • RH attemperator outlet temperature

RH = reheater; SH = superheater.

Condensate and Feedwater Flow Controls

Feedwater flow control frequently has at least two modes of operation to address startup/low load conditions compared with higher load operating conditions (that is, single-element control and three-element control). Flow recirculation in the HRSG is also used to control gas and water temperatures.

Table C-5
Feedwater control loop

Description	Key Parameters
Directs condensate and feedwater flows to provide level control for the LP, IP, and HP steam drums. Methods for feedwater flow control may include pump speed, flow control valves, and recirculation.	• Control mode • HP/IP boiler feed pump speed • Feedwater control valve position • HP steam flow • HP feedwater flow • HP drum level • IP steam flow • IP feedwater flow • IP drum level • IP drum pressure control • Condensate pump speed • Condensate control valve position • Feedwater recirculation valve position • LP drum level

HP = high pressure; IP = intermediate pressure; LP = low pressure

Duct Burner Management System

Duct burners typically operate to support the high end of the unit load. When the combustion turbines reach their full load, the duct burners increase the exhaust gas temperature to supplement the HRSG steam production to the steam turbine.

Table C-6
Duct burner management

Description	Key Parameters
Feeds fuel at a set combustion rate in the HRSG. Also ensures safe initiation and removal of burners from service.	• Combustion turbine load • Fuel valve position • Duct burner fuel flow • SH temperature • Flame indication • Igniter status

Vendor Limits Incorporated in Controls

The initial limits on process parameters affected by the key control loops are most often based on vendor-imposed limits for components or systems. Table C-7 lists the source for the unit's specific limits that should be identified when the unit ramp rate improvement is planned. The basis for the vendor-imposed limit also should be examined to identify the margin available for unit ramp rate improvement. Table C-7 provides the nominal basis of the concern addressed by the vendor-imposed limits.

Table C-7
Vendor-imposed limits

Vendor	Parameter	Typical Basis of Concern
Combustion turbine	Turbine thermal cycle	Fatigue of rotating elements
	Firing temperature	Local overheating of rotating elements NO_X emissions control
HRSG	Superheater and reheater steam temperatures	Steam temperatures exceed long-term operating limits of tube, header, or interconnecting piping materials Spray flow swings impose temperature cycles on interconnecting piping, header, and tube stresses
	HP/IP/LP steam pressure	Pressure fluctuations decrease life of drum, headers, and interconnecting piping
	HP/IP/LP drum thermal cycle	Steam temperature transients due to evaporation pressure transients
Steam turbine	Thermal cycle	Steam temperature transients
	Rotor expansion	Steam temperature transients
	Exhaust hood temperature	Changing pressure conditions during transient load conditions impacts exhaust temperatures
Air emissions permit	NO_X	Limits on reaction at lower flue gas conditions Mismatch of combustion air distribution during transient load conditions
	NH_3	Burnoff of deposits on catalyst can result in excursions Improper control of ammonia addition during transient load conditions

HP = high pressure; IP = intermediate pressure; LP = low pressure

Mitigation Actions for Ramp Rate Limitations

Ramp rate improvement depends on the diagnosis of the individual factors limiting the rate of generation increase and implementing changes to mitigate those limitations. Each factor must be identified separately, typically through observation of a unit load ramp. Therefore, mitigation of each limit, by changes in control logic, operator process, or equipment modification, must be implemented individually before the next limiting factor can be identified.

The sequential nature of ramp rate limitation diagnosis requires that mitigating approaches be available for each limit. Tables C-8 through Table C-13 provide guidance on potential mitigating approaches for ramp rate limits with the most potential impact at combined-cycle units. These mitigating approaches are discussed in relation to the control loop in which the potential ramp rate limitation could occur. Implementing some of these mitigating approaches require control system logic reprogramming.

Table C-8
Mitigation approaches to unit demand management related limits

Potential Ramp Rate Limitation		Mitigation Approach
1	Control logic does not implement ramping at vendor stated capability of combustion turbine.	Evaluate how load increase/decrease signals are transmitted to the combustion turbines.
2	Control logic between steam turbine and combustion turbine introduces limit on ramp rate.	Evaluate translation of steam turbine ramp rate limitations into ramping parameters of the combustion turbine control logic.

Table C-9
Mitigation approaches to combustion turbine related limits

Potential Ramp Rate Limitation		Mitigation Approach
1	Control logic does not implement ramping at vendor stated capability of combustion turbine.	Update control logic to reflect the vendor-stated limits.
2	Vendor stated capability of combustion turbine is below component capability.	Incrementally update control logic to expand the operating range achieved during ramping periods. Compare combustion turbine ramp rate limit to the specific design capacities of combustion turbine. Evaluate the significance of ramp load change to the overall life of the combustion turbine.

Table C-10
Mitigation approaches to steam turbine related limits

Potential Ramp Rate Limitation		Mitigation Approach
	Control logic does not implement ramping at maximum capability of steam turbine.	Evaluate how steam turbine ramp rate limitations in installed control logic relate to physical capabilities of the equipment. Evaluate the significance of load change to the overall life of the steam turbine.

Table C-11
Mitigation approaches to steam temperature control related limits

Potential Ramp Rate Limitation		Mitigation Approach
1	SH temperatures exceed alarm limits.	Add a counter to account for the short-term nature of the high temperature alarm.
2	RH temperatures exceed alarm limits.	Add a counter to account for the short-term nature of the high temperature alarm.

Table C-12
Mitigation approaches to condensate feedwater control related limits

Potential Ramp Rate Limitation		Mitigation Approach
1	Unstable feedwater flow control during low load portion of ramp.	Manually open the recirculation system to increase the operating point of the feedwater control valve. Return to automatic operation when feedwater demand exceeds 30 percent.
2	Unstable drum level control (LP, IP, or HP).	Change setpoints for transition from single-element to three-element control.

HP = high pressure; IP = intermediate pressure; LP = low pressure

Table C-13
Mitigation approaches to duct burner management system related limits

Potential Ramp Rate Limitation		Mitigation Approach
1	Excessive time delay programmed in flame proving system.	Update the local interlocks in flame proving device to reduce flame stability assessment delays.
2	Duct firing exclusive to high combustion turbine loads.	Change interlock to allow duct firing at lower combustion turbine loads to increase rate of steam production.

The mitigating approaches identified in the previous tables may impact other areas of the unit operation during ramping. The specific mitigating action(s) and the extent of the change applied will vary based on the specific unit design. A unit-specific balance among mitigating approaches will need to be developed as part of the ramp rate improvement process.

The mitigating approaches discussed in the appendix are not intended to cover all potential ramp rate limitations. They provide a reference for the typical mitigating actions applicable to combined-cycle power plants.

Pilot Implementation of a Ramp Rate Diagnosis

Development of the unit ramp rate optimization methodology included a limited-scope, pilot implementation at a natural gas-fired combined-cycle generating unit. This section illustrates the findings from the pilot ramp rate diagnosis testing (Methodology, Step 4). Discussion of the findings focuses on illustrating the improvements identified during the pilot testing.

The pilot implementation efforts did not attempt to complete the optimization of the ramp rate on the host unit. Further work is necessary to fully develop the ramp rate potential of the host unit; recommendations at the end of the appendix describe this work.

Background

The host utility for the pilot implementation was interested in improving the ramp rate of its natural gas-fired combined-cycle unit to enhance its competitiveness in the wholesale electricity market. The unit's declared ramping capability was 12 MW/minute for the electricity market. No work had been performed by the host unit personnel prior to the pilot test to improve the unit ramp rate. Further, no specific targets were identified for the improvement desired to optimize the combined-cycle unit's competitiveness in the electricity market.

Unit Background

The pilot implementation testing was hosted by a 2×1 combined-cycle unit equipped with GE 7FA combustion turbine generators (CTGs), Foster Wheeler HRSGs, and a GE D11 steam turbine generator (STG). The CTGs are each rated for 183.6 MW_{GROSS}, and the STG is rated for 258.4 MW_{GROSS} (all with 0.85 power factor). The combustion turbines have dual fuel combustion capability (natural gas or oil firing) and were upgraded with the GE Advanced Gas Path upgrade. The host unit did not have the updated combustion turbine control settings specification that was developed for the Advanced Gas Path installation. The steam turbine has a high pressure section, an intermediate pressure section, and a low pressure section. Each HRSG generates steam at three pressures (high, intermediate, and low) and includes an RH section. The STG operates in the sliding pressure mode (that is, valves are wide open) down to minimum high, intermediate, and low pressures, at which point the control valves modulate to maintain minimum pressures. Both the combustion turbines and the steam turbine are operated with GE Mark VI control systems. A Honeywell system provides balance of plant (BOP) controls and supports communications between the steam turbine and combustion turbine control systems.

The host unit includes several features to boost generation. Evaporative coolers at the air inlets can be used to increase the combustion turbines' output when ambient air temperatures are high. In addition, the combustion turbines can be fired in a peak load mode to maximize their output (above the baseload capability). Duct burners can supplement the heat input to each HRSG, boosting steam production and, consequentially, the steam turbine output.

The baseload unit capacity without evaporative cooling and duct firing is 559 MW_{GROSS}. Table C-14 provides the nominal output of the prime movers in this operating mode.

Table C-14
Nominal output of the host combined-cycle unit

Prime Mover	Capacity, MW_{GROSS} (Ambient Conditions 59 F [15°C], 60% Relative Humidity)
Combustion turbine 1 (Baseload, evaporative coolers shut off)	184
Combustion turbine 2 (Baseload, evaporative coolers shut off)	184
Steam turbine (Duct firing shut off)	191
Total	559

A carbon monoxide catalyst and a selective catalytic reduction (SCR) catalyst are included in each HRSG to control air emissions. The combustion turbines are equipped with dry low NO_X combustors (GE DLN 2.6 design). Aqueous ammonia is injected just upstream of the SCR catalyst for final NO_X control.

Test Runs

Diagnosis testing was performed to identify improvements in the ramp rates of the host unit. All of the testing was performed with the unit operating in 2×1 mode and firing natural gas. Generally, the load range for the ramp rate testing extended from the combustion turbine minimum operating point and up to the baseload (shown in Table C-14). Some variation in the baseload capability was experienced due to changes in ambient air conditions, but this was not significant to the ramp rate capability. No testing with duct firing or evaporative coolers was performed.

Nine ramps were performed over 6 days of testing at the host unit. Figure C-2 shows the load ramping operations tested; all of the tests are shown on a common elapsed time X-axis. Table C-15 summarizes the objectives and findings of each test. Some of the tested ramps started at low load, whereas others started at full load. Most of the load ramps tested involved both up and down ramps. In some cases, only one combustion turbine was ramped to understand a controls setting effect. All of the tests were completed within 80 minutes of their start.

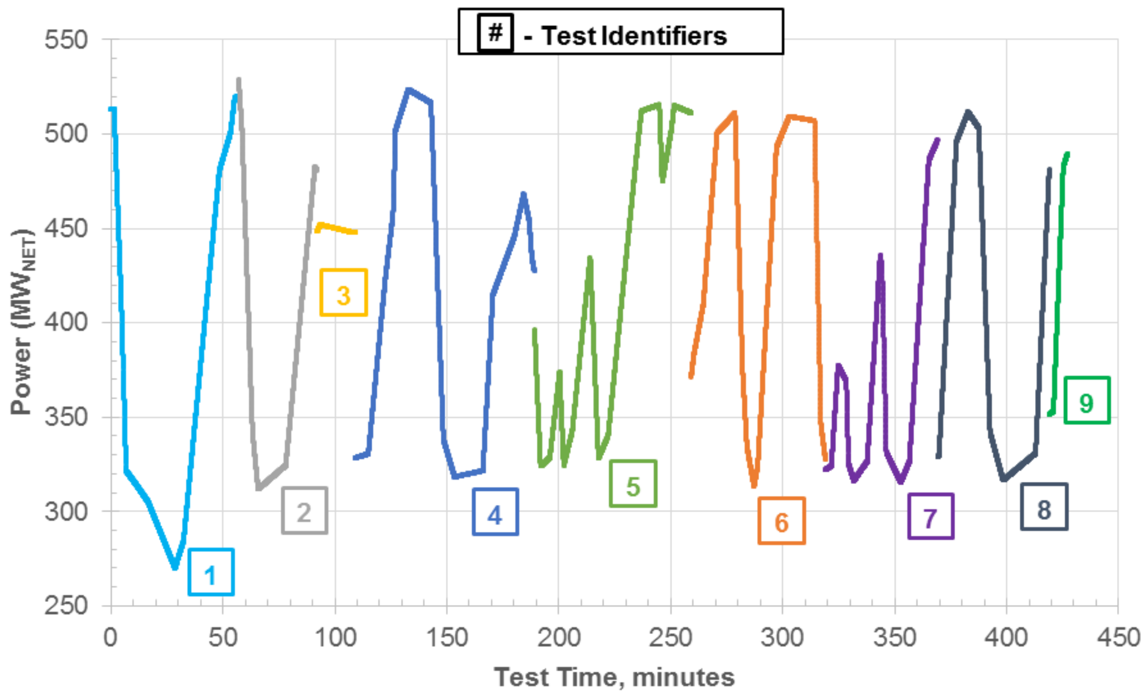

Figure C-2
Ramp rate diagnosis of the pilot tests

Table C-15
Summary of diagnosis testing

Test Identifier	Test Objective	Finding
1	Observe down and up ramp with normal control settings.	Unit ramped up at +12 MW/min. Unit ramped down at -42 MW/min. First part of down ramp faster than normal since evaporative coolers were shut off at start of ramp. Latter part of down ramp included going into different combustion modes for the combustion turbines at very low loads.
2	Observe down and up ramp with normal control settings. CTGs kept in normal combustion modes and evaporative coolers shut off for entirety of test period.	Unit ramped up at +12 MW/min. Unit ramped down at -34 MW/min.
3	Ramp up and then down using direct setpoint change in combustion turbine Mark VI controls (only one CTG) to separate effect of BOP controls.	Direct setpoint change did not result in faster ramps.
4	Ramp up with modified settings on BOP control system combustion turbine pulse controllers, and then ramp down using direct setpoint change in combustion turbine Mark VI controls to separate effect of BOP controls.	CTGs ramped at faster rate with modified settings on BOP control system.

Table C-15 (continued)
Summary of diagnosis testing

Test Identifier	Test Objective	Finding
5	Evaluate response to sawtooth load change pattern over constrained load range with normal combustion turbine pulse controller settings, and then ramp down using direct setpoint change in combustion turbine Mark VI controls to understand BOP controls signals effects.	Unit ramped up at +12 MW/min. Unit ramped down at -30 MW/min. Found that pulses are required from BOP system to change CTG load (continuous setpoint change in Mark VI was interpreted as a fault condition).
6	Evaluate response to sawtooth load change pattern over full load range with varying modifications to BOP control system combustion turbine pulse controller settings.	Confirmed ability to improve CTG ramp rates with modified BOP controls system settings.
7	Evaluate response to sawtooth load change pattern over full load range with modified BOP control system combustion turbine pulse controller settings.	Process parameters were stable throughout sawtooth load pattern with modified BOP controls system settings.
8	Evaluate how BOP control system settings (ramp rate limiter and combustion turbine pulse controller) impact ramp up rate.	Unit ramped up at +25 MW/min. Unit ramped down at -32 MW/min.
9	Demonstrate how modified settings for BOP controls (system ramp rate limit and combustion turbine pulse controller) can improve ramp rate.	Unit ramped up at +30 MW/min.

Findings

In the ramp rate pilot testing performed, the combustion turbines’ heat input to the HRSGs set the steam production rate. Therefore, the steam turbine ramp rate was also set by the combustion turbine ramp rate. This relationship between the ramp rates of the turbines in the 2×1 host unit configuration is illustrated in Figure C-3.

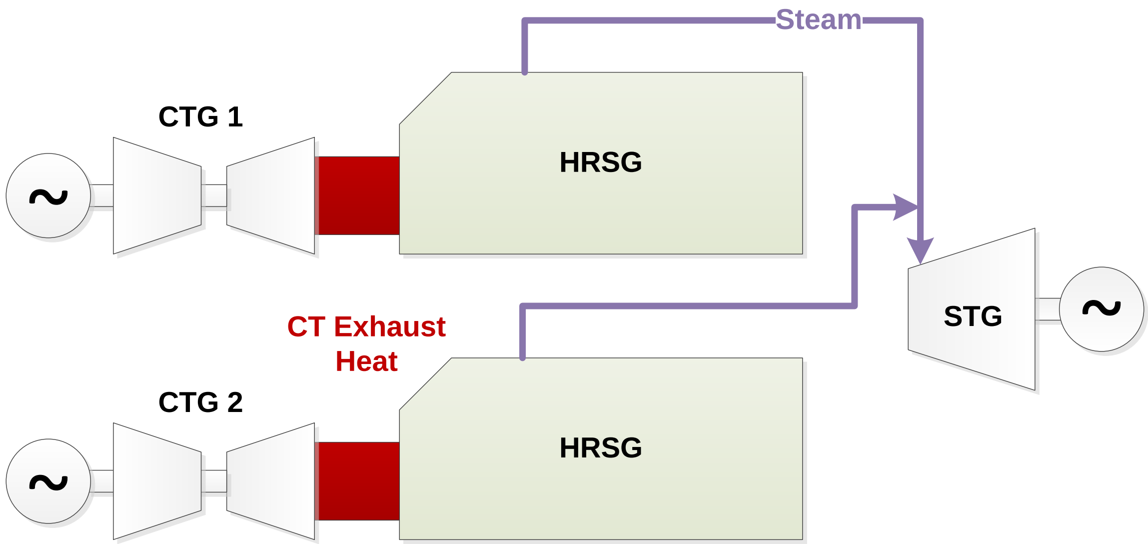

Figure C-3
Ramp rate pilot testing of the relationship between combustion turbines

The GE CTG Mark VI controls settings for the host unit allowed each CTG to ramp up at a maximum rate of +14.5 MW/minute and ramp down at a maximum rate of -29.4 MW/minute. However, the as-found BOP controls limited the combustion turbine ramp rates to less than the maximums included in the logic of the Mark VI controls.

The opportunities identified during the pilot testing to improve the unit controls are summarized in the next paragraph. The opportunities developed for the pilot unit were limited by the duration and focus of the tests. However, the opportunities evaluated are considered representative of specific areas to improve ramp rates at other natural gas-fired combined-cycle units.

Prime Mover Controls Improvement

The Honeywell BOP controls facilitate communication between the STG controls and the CTG controls. As shown in Figure C-4, there are two main types of communication impacting unit ramp rates: (1) ramping limits and (2) raise/lower signals. The installed Honeywell BOP controls were found to limit the ramping performance for the host unit, so changes to the BOP controls were an opportunity to improve ramping performance.

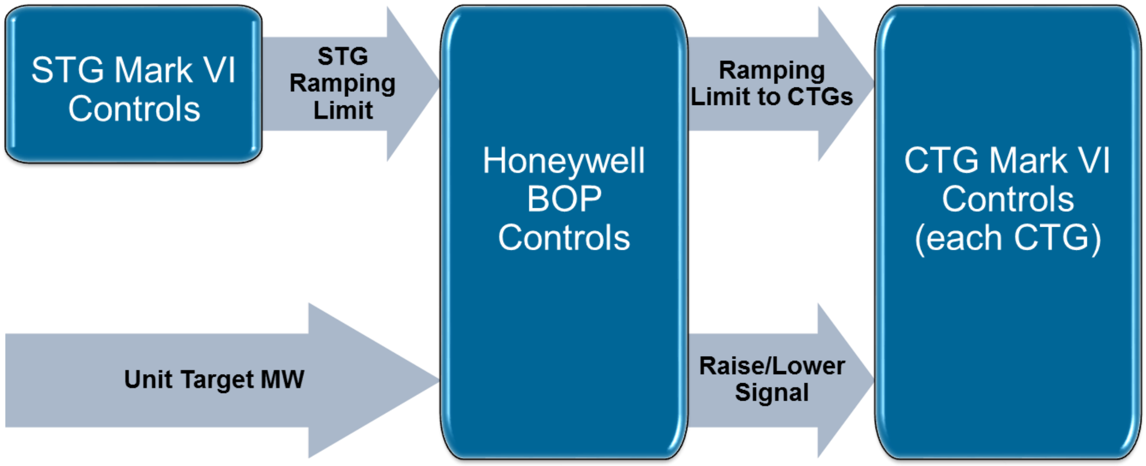

Figure C-4
Relationships of the host unit controls and signals

Ramping Limits

In the host unit's controls, the STG ramping limit is passed through the BOP controls to ensure that the combustion turbines' ramp rates maintain the STG ramp rate within its limits. Typical GE practice is to limit STG ramps to a maximum of 10% per minute: ±25.8 MW/minute for the host unit. The STG controls included provisions to modify the allowed ramp rate as a function of STG component stress (inferred from other parameters), differential expansion, rate of change of stress, and rate of change of expansion. As a result of these four inputs, the STG can reduce the allowed ramp rate below 10% per minute (for example, during startups). Conditions to reduce the allowable STG ramp rate were not encountered during the pilot tests. The STG ramping limit signal was maintained at its maximum value of 10% per minute throughout the pilot testing.

The BOP controls translate the STG ramp rate limit into ramp rate limits for the CTGs. The STG signal is translated differently based on the number of combustion turbines in service (that is, in 1×1 mode or 2×1 mode). The host unit's installed BOP controls translated the STG ramping limit, as follows:

- The STG-allowed ramping limit of 10% per minute is interpreted as a 100% signal by the BOP controls.
- When operating in 2×1 mode, the STG ramping limit signal is multiplied by 0.50, but the lowest allowed result is 60%.
- When in 1×1 mode, the STG ramping limit signal is multiplied by 1.0.

During unit ramps up, the CTG Mark VI controls follow the BOP limit up to the maximum limits allowed in their Mark VI controls. At the host unit, the 60% ramp rate limit signal from the BOP controls when operating with two CTGs limits each CTG to +8.8 MW/minute ramping up. When the host unit was operating with one CTG, the BOP controls limit would ramp up the CTG at the 14.5 MW/minute allowed by the CTG Mark VI controls. During ramps down, the host unit CTG Mark VI controls ignore the values passed along by the BOP controls. Therefore, down ramp rates of -29.4 MW/minute per CTG were permitted.

Raise/Lower Signals

The second type of ramping operation communication through the BOP controls involves the receipt and transmittal of raise and lower signals for the CTGs (see the lower part of Figure C-4). The BOP controls take the input signal for the combined-cycle unit's target MW output and generate raise/lower signals based on the error between the actual output and the target. The BOP controls transmit raise/lower signals as pulses to each CTG's Mark VI controller.

Two variables in the Honeywell BOP controls implement the raise/lower pulses, including CYCLETIM that sets the frequency of pulses from the BOP controller to the CTG Mark VI controller and MAXPULSE that sets the maximum duration of the pulse within each cycle.

Figure C-5 illustrates how these variables affect the raise/lower pulses.

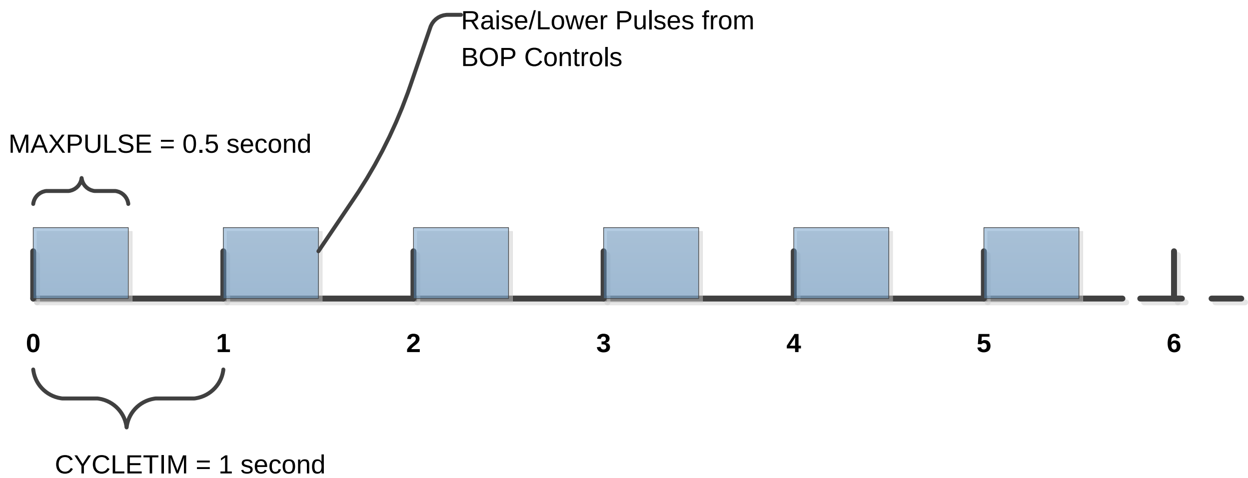

Figure C-5
Raise/lower pulses from BOP controls to CTG controls

The as-found pulse settings in the Honeywell BOP controls were observed to limit the CTG ramp rates. Figure C-6 illustrates the as-found ramp up performance of the unit and each turbine. The overall change in unit power is plotted on the left axis and shown with the *blue* line. The combined unit ramp rate (+12 MW/minute) is plotted on the right axis and shown with the *green* line. It should be noted that these data are an excerpt of data from Test 2 (see Figure C-2), but the test time shown on the X-axis is specific to the Test 2 duration.

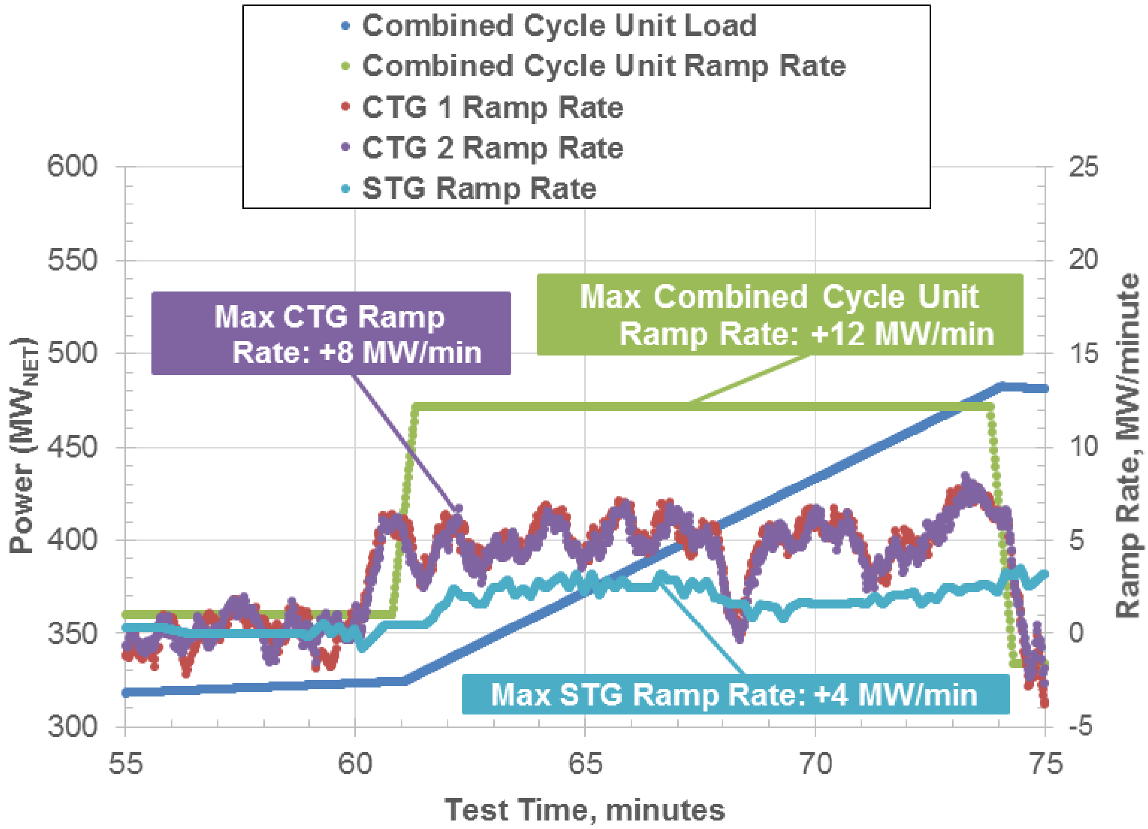

Figure C-6
Test 2 unit ramping performance with as-found controls settings

The individual combustion turbine and steam turbine ramp rates during the period of the test are also shown in Figure C-2. The as-found controls settings for the combustion turbines do not maintain a steady ramp rate and do not consistently achieve the +8.8 MW/minute allowed by the BOP controls. The STG ramp rate is also well below the GE limit of +25.8 MW/minute. The result is an overall unit ramp rate of +12 MW/minute.

The pilot testing specifically identified three areas to improve BOP controls settings to increase the unit ramp rate. Table C-16 illustrates the as-found and the optimal settings identified from the series of nine pilot tests.

Table C-16
Modifications to Honeywell BOP controls identified in diagnosis testing

Parameter	As-Found Setting	Modified Setting	Notes
Pulse CYCLETIM, seconds	1.0	1.0	Over the series of tests, it was determined that the CYCLETIM should remain at 1 second.
Pulse MAXPULSE, seconds	0.5	0.974	The Honeywell BOP controls system has one pulse controller for each CTG, and the MAXPULSE parameter was modified in each controller.
Load rate limiter	60%	100%	The load rate limiter sets the minimum allowed output from the BOP controls in translating the STG ramp rate limit to the CTGs. The load rate limiter was modified during the testing to illustrate how changing the translation could achieve higher unit ramp rates. As-found, the STG ramping limit signal is multiplied by 0.50 when operating in 2×1 mode. For final implementation, this STG signal multiplying factor should be considered in conjunction with the load rate limiter.

The optimal BOP controls settings were demonstrated in Test 9. Following Test 9, the BOP controls were returned to their as-found settings. As discussed later in this appendix, challenges with the as-found condition of the combustion turbines placed additional restrictions on the operation of the host unit. Implementation of permanent controls changes required further consideration of the potential impacts on the degraded equipment of higher ramp rates.

The ramp rate improvement demonstrated in Test 9 is illustrated in Figure C-7. The information plot is presented similarly to Figure C-6, except the X-axis testing durations are specific to Test 9. The modified Honeywell BOP controls settings resulted in CTG ramp up rates that matched those allowed by the Mark VI controls, and the overall unit ramp rate improved to 30 MW/minute. The ramp rates for the two CTGs differ slightly in Test 9 because of slightly different controls settings during the test.

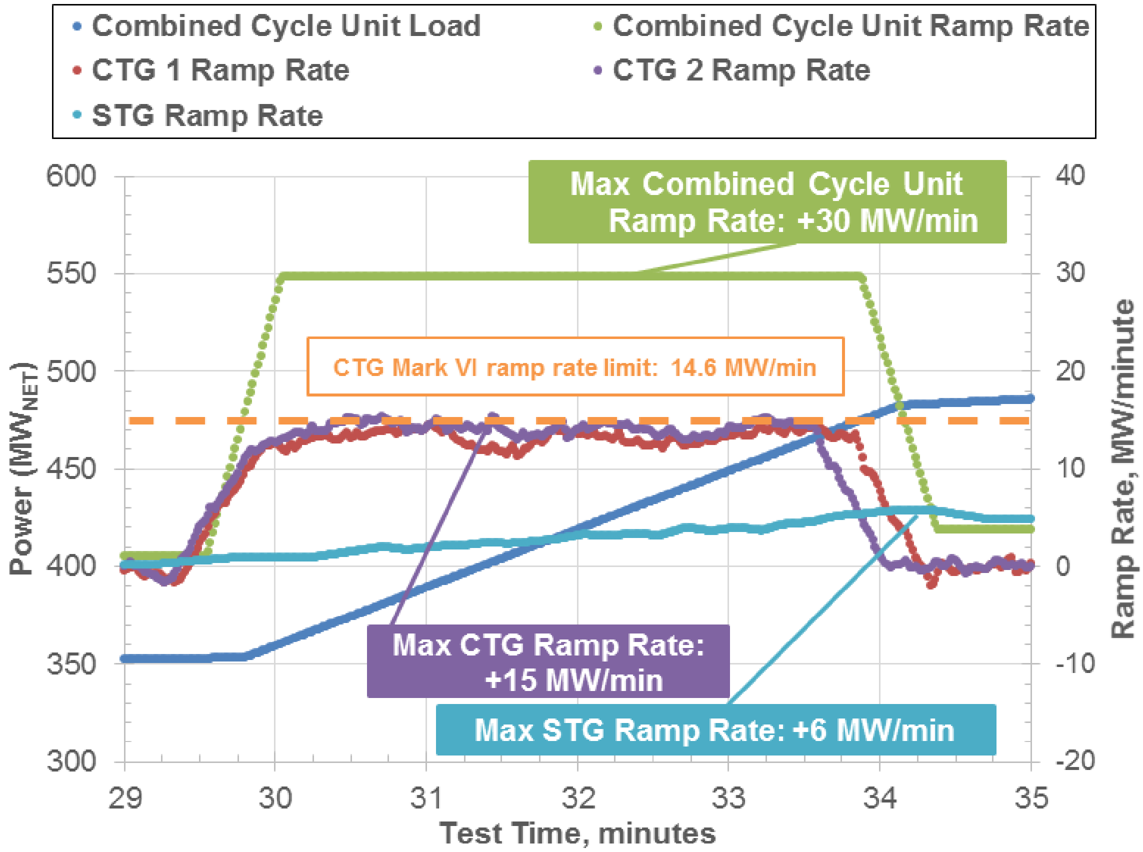

Figure C-7
Test 9 unit ramping performance with modified controls settings

The combined-cycle unit ramp rate of +30 MW/minute observed in Test 9 is mainly the result of the two CTGs ramping at 15 MW/minute. The steam turbine reacts after the increased CTG heat input to the HRSG increases the steam production. This dependence results in the slower ramp for the steam turbine. The STG ramp rate limit of 10% per minute is not challenged by the ramping conditions used in Test 9.

Table C-17 summarizes the as-found and improved ramping performance demonstrated during the pilot testing. The changes in the BOP controls settings were successful in improving the combined-cycle unit's ramp up capability. While down ramps were observed in the pilot testing, a down ramp with improved Honeywell BOP controls was not tested because of combustion turbine condition concerns, as discussed later in this appendix.

Table C-17
Combined-cycle unit ramp rate improvement summary

Values	CTG Ramp Rates, MW/min	STG Ramp Rate, MW/min	Overall Unit Ramp Rate, MW/min
Up Ramps			
Mark VI control system limits	+14.5	+25.8	–
BOP control system limits	+8.8	+25.8	–
As-found ramp performance	+8	+10	+12
Improved ramp performance	+15	+6	+30
Down Ramps			
BOP control system limits	-29	-25	–
As-found ramp performance	-18	-26	-34

Ramping Impact on Key Operating Parameters

The combined-cycle unit process parameters stayed within the vendor specified limits during the ramping operations. The monitored process parameters included the following:

- NOx emissions
- Low pressure drum pressure rate of change
- Intermediate pressure drum pressure rate of change
- High pressure drum pressure rate of change
- High pressure steam pressure
- High pressure steam temperature
- RH steam temperature
- High pressure steam turbine steam temperature rate of change
- STG first stage bowl temperature rate of change
- STG differential expansion
- CTG load ramp rate
- STG load ramp rate

The following figures show the observed trends for a few key parameters during Test 9, which demonstrated the fastest ramp up rates during the pilot testing. These reported trends are characteristics of the results of changing the ramp rates at the host unit.

Figure C-8 shows the NOx emissions during Test 9. The air permit limit was not challenged in the ramping period.

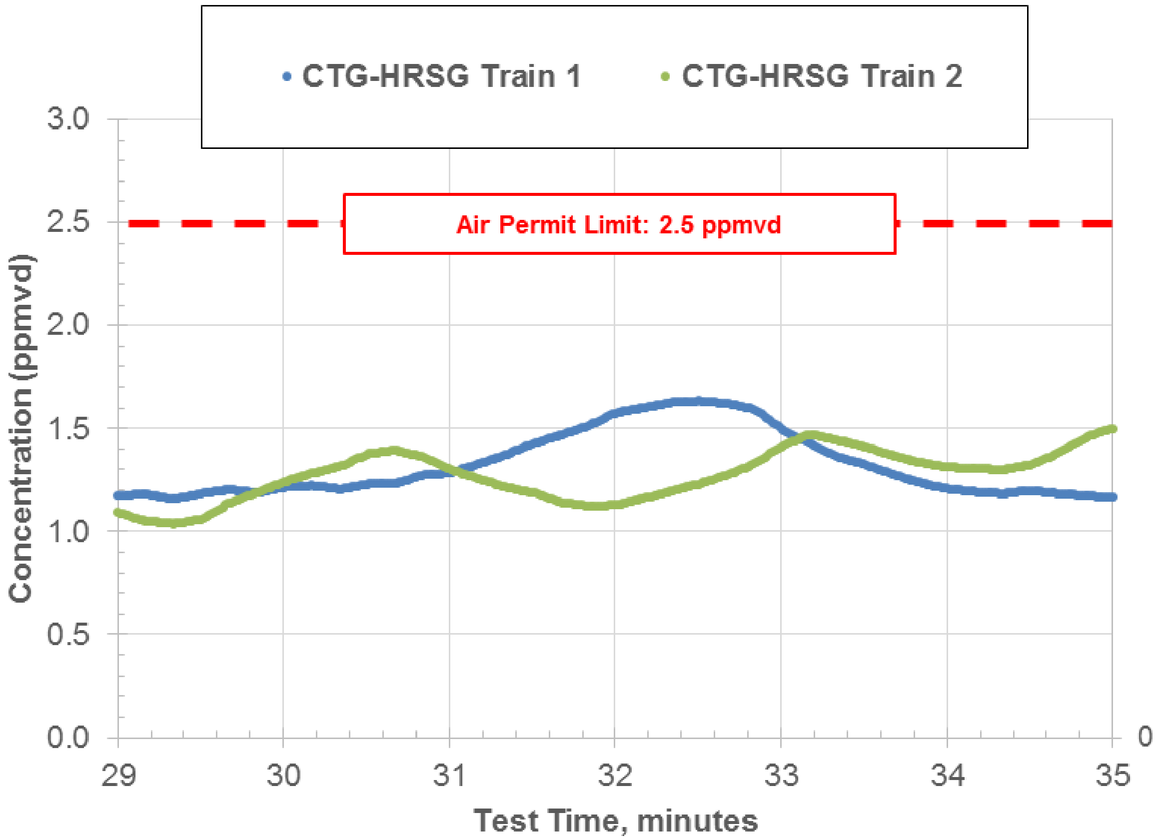

Figure C-8
Test 9 unit NO_X emissions during a ramp up

The startup procedures include limits on the allowed rates of change for the high, intermediate, and low pressure drums. These pressure rate of change limits serve to control temperature changes in the evaporation sections of the HRSG. Figure C-9 shows the drum pressures during Test 9 in one of the HRSGs (the other HRSG performed similarly). The drum pressures changed at rates within the startup limits during the ramping period.

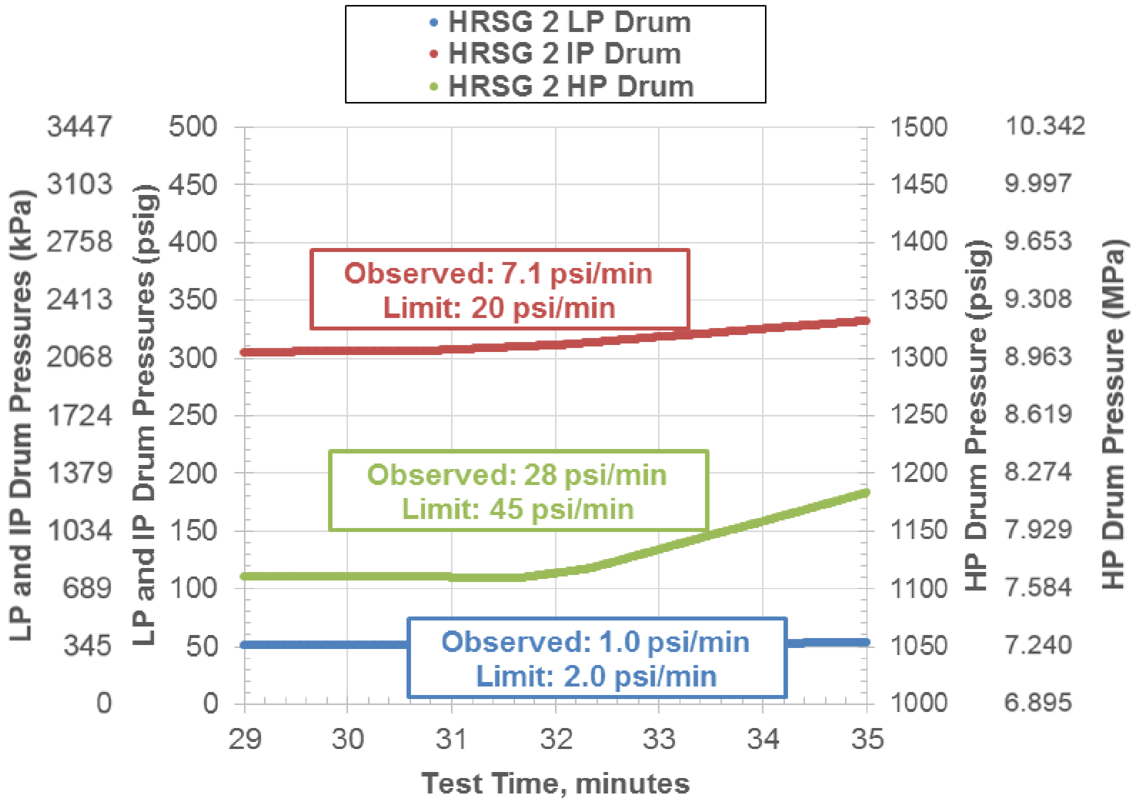

Figure C-9
Test 9 HRSG 2 drum pressure changes during a ramp up

The GE STG operations and maintenance manuals provide guidance on the effect on the turbine life of changes in inlet steam conditions. The guidance considers both the range of temperatures encountered in a cycle and the rate of change of the temperatures. Table C-18 presents the worst case pilot test data in comparison with the GE guidance. The high pressure steam turbine cycles resulting from the pilot test ramps were below the limits provided by GE. This observation is consistent with other GE guidance that states “negligible cycle life expenditures” are expected when changing STG load between 30% and full load.

Table C-18
Test data and GE guidance for steam turbine thermal cycles

Values	HP Steam Turbine Temperatures	
	Range (Max-to-Min)	Rate of Change
Test data	31°F (17°C)	369°F/hr (205°C/hr)
GE guidance	< 75°F (42°C) not considered a cycle by GE	600°F/hr for 100°F (333°C/hr for 56°C) Bowl metal change for 0.001% life expenditure per cycle

HP = high pressure.

HRSG Component Fatigue Evaluation

Similar to the steam turbine thermal cycles, ramping operations have the potential to introduce low cycle fatigue cracks in HRSG pressure parts. Except for the drum pressure rate of change, limits for startup previously discussed, this study did not evaluate Foster Wheeler guidance on pressure/temperature changes and HRSG component fatigue life. However, a simple evaluation was performed based on understanding the maximum pressure range and temperature differential for each HRSG component that would **not** be significant to its design life. The ASME Boiler and Pressure Vessel Code was used for guidance in identifying operating cycle conditions that exempt components from fatigue analysis. The Code exempts components from analysis of cycles that have pressure ranges ≤15% of the design pressure and metal temperature differentials of ≤50°F (28°C).

The HRSG steam pressure range is a function of the changes in load, not the ramp rate. The thermal stress is a function of the ramp rates, with the worst temperature differentials (that is, the highest stresses) during fast ramps.

A screening evaluation was performed for the host unit HRSG components based on this approach. Table C-19 shows the worst case pressure and temperature results from the pilot tests and the relevant comparison points for the ASME analysis exemption. The temperature ranges are based on calculated changes in saturation temperatures as a function of the observed changes in pressure.

Table C-19
Test data and ASME Code limits for fatigue analysis exemption

Pressure/Temperature Parameter	Drum			ASME Exemption Limit
	LP	IP	HP	
Steam drum design pressure	100 psig (689 kPa)	590 psig (4070 kPa)	2180 psig (15.0 MPa)	
Maximum pressure range from ramp testing	18.6 psi (128 kPa)	112 psi (772 kPa)	273 psi (1.9 MPa)	
Pressure range fraction of design	19%	19%	13%	<15%
Maximum temperature range from ramp testing	17°F (9°C)	30°F (17°C)	28°F (16°C)	<50°F (<28°C)

HP = high pressure; IP = intermediate pressure; LP = low pressure.

Given that the changes (in pressure and temperature expected when ramping within the load range) demonstrated in the pilot testing are relatively small, it is likely that the HRSG components can handle these operations without premature fatigue failures. Further, the HRSGs were designed for the use of duct firing, which significantly increases the steam pressure changes beyond those that resulted from ramping the CTGs.

The temperature ranges observed in the testing are all within the ASME exemption limits. The high pressure drum pressure range is also within the exemption limit. The low and intermediate pressure drum pressure ranges, however, exceed the exemption limits. Fatigue analysis for these ramping cycles would be required per the ASME Code to design the host unit HRSGs for ramping operations similar to those demonstrated in pilot testing.

It should be recognized that only the steam drums were considered in this screening analysis. A complete evaluation should include consideration of high pressure SH headers, RH headers, low pressure SH headers, as well as the steam drums.

Combustion Turbine Material Condition

GE has advised power plant operators with 7FA combustion turbines that the compressor rotor wheels can develop cracks from normal operating cycles. GE has issued a Technical Information Letter (TIL) about this issue (TIL 1972), and EPRI has previously considered compressor rotor cracking in an overall study of F-class combustion turbine damage mechanisms (References C.1 and C.2, respectively). Startup/shutdown cycles are known to initiate cracks and propagate growth at flat slot bottoms on compressor stages 12 through 17. EPRI investigations indicate that cracks initiate after approximately 200 starts.

GE recommends that compressor rotor wheels with flat slot bottoms be inspected after 1,700 starts. As soon as cracks are observed, GE sets a re-inspection interval based on crack measurements. The re-inspection interval is defined in terms of cycles that count actual fired starts and load swings. Load swings are considered a fraction of an actual fired start for the purpose of counting cycles. Any combustion turbine ramp at faster than 1 MW/minute is considered a load swing, and GE considers down ramps to create the most severe stress condition for propagating crack growth. Above a ramp rate of 1 MW/minute, the key driver for crack growth is the size of the load swing and not the combustion turbine ramp rate.

The host unit’s combustion turbines have started approximately 1,700 times. The host unit is operated with regular load swings within the minimum to baseload capability of the combustion turbines, and overnight shutdowns are also common. Compressor rotor wheel cracks have been observed in borescope inspections of the host unit’s combustion turbines. However, crack dimensions were not measured during the inspections. The host unit owner plans to schedule maintenance on the combustion turbines no earlier than 2021 and 2022.

The risks are significant if the compressor rotor cracks grow too far. The operating risks include blade liberation or rotor wheel burst failures. To delay crack initiation and to slow crack growth, GE advises that operators with at-risk combustion turbines consider changes in combustion turbine operation, as follows:

- Minimizing startups/shutdowns
- Prioritizing startups and shutdowns to units with lower start rotors
- Using turndown in lieu of shutting down
- Minimizing forced cool-downs

- Performing full speed no load (FSNL) holds on shutdowns
- Performing warm restarts (within 8–10 hours of shutdown)
- Minimizing fast starts

Conclusions and Recommendations

The diagnosis test results identified control modifications that would improve ramping operations and highlighted the need for further evaluations prior to permanent changes to the host unit's ramp rate.

Near-Term

The pilot testing demonstrated that changes in the controls system will enable the host unit to ramp at higher rates. However, the host unit must consider the material condition of the combustion turbine compressor rotor wheels, which are known to have cracks, in increasing ramp rate capability. Near-term actions are recommended, as follows:

1. The host unit should request that GE provide the updated combustion turbine control settings specification that was developed for the Advanced Gas Path installation. This control settings specification will confirm that GE's latest update does not impose ramp controls limits not considered in the pilot testing.
2. The host unit owner should assess the available facts regarding the condition of the combustion turbine compressor wheel cracking and the variables for the future operations and maintenance, as follows:
   - Key available facts are as follows:
     - When was borescope inspection performed?
     - Which compressor rotor wheels have been inspected (Stages 12–17)?
     - Where were cracks sighted?
     - What is size of observed cracks?
     - What is the rotor geometry?
     - What are the compressor temperatures?
     - What are the number of actual starts and load swings since the inspection?
   - Key variables for future operations and maintenance are as follows:
     - Planned timing of next major overhaul
     - Scope of next major overhaul ("1972" inspection, or repair/replace rotors?)
     - Planned actual fired starts per year
     - Allowed range of load swings
     - Allowed number of load swings per day

  - Changes in forecast revenue and expenses with any changes in the following:
  - Maintenance timing
  - Limits on the ability to follow energy markets

   This assessment should determine the most appropriate operating limitations and future maintenance plans for the combustion turbines.

3. The host unit owner should contact Foster Wheeler to confirm that load swings of the type tested in this study will not lead to premature HRSG pressure part fatigue failures. Scoping evaluations presented in this study suggest that the load swings are acceptable for the HRSG drum components.
4. Assuming no new limits are identified from the updated combustion turbine control settings specification, the assessment of the combustion turbine compressor wheel material condition and input from Foster Wheeler, the host unit should modify the Honeywell BOP controls to allow the CTGs to ramp up at 14.6 MW/minute, which will match the GE Mark VI control system limits.

   In implementing this controls change, the host unit should consider modes of operation outside of those considered in the pilot testing (for example, the increased CTG ramp up rate should not be allowed to cause the STG to exceed its allowed ramp rate during startup operations).

5. Because GE considers down ramps to be an important contributor to compressor rotor crack growth, the host unit should modify the control systems to limit the rate for lowering combustion turbine load to -14.6 MW/minute. The current combustion turbine Mark VI controls allow -29 MW/minute, but the as-found Honeywell BOP controls limit each combustion turbine's down ramp rate to -18 MW/minute.

   In implementing this controls change, the host unit should consider modes of operation outside of those considered in the pilot testing (for example, the decreased CTG ramp down rate should not be allowed to hinder equipment protection runbacks in load).

Future

This report suggests that even higher ramp rates are possible with the host unit's equipment. The GE 7FA combustion turbines are likely capable of ramping at ±30 MW/minute. Further testing and equipment assessments will be required prior to the implementation of ramp rates this fast. As a first step, the host unit's owner should consider the value and potential costs of faster ramps. The host unit's owner should determine the following:

- Energy market value and ancillary services market value for the host unit with different ramp rate settings
- Costs in the event that faster ramps put the CTGs into a different maintenance interval requirement

If the financial assessment shows positive value for faster ramping, testing and assessment of the technical issues should be performed prior to the implementation of any further increase in the ramp rate. The assessment and testing should follow the methodology described in this report and, at a minimum, consider the issues presented in this appendix.

Case Study References

C.1 *Gas Turbine Rotor Life: GE 7FA Status Report*. EPRI, Palo Alto, CA: 2016. 3002008863.

C.2 GE Power, *F-Class Conical Flat Slot Bottom (FSB) Compressor Wheel Recommendations*, TIL 1972-R2, 07 July 2017.

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