CALIFORNIA ENERGY COMMISSION

Energy Research and Development Division

FINAL PROJECT REPORT

Investigating Flexible Generation Capabilities at the Geysers

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PREPARED BY:

Primary Authors:
John Farison
Julio Garcia
Brian Benn

Calpine/Geysers Power Company, LLC
10350 Socrates Mine Road
Middletown, CA 95461
Phone: 707-431-6000
http://www.Calpine.com
http://www.Geysers.com

Contract Number: EPC-14-002

PREPARED FOR:
California Energy Commission

Hassan Mohammed
Project Manager

Jonah Steinbuck, PhD
Office Manager
ENERGY GENERATION RESEARCH OFFICE

Laurie ten Hope
Deputy Director
ENERGY RESEARCH AND DEVELOPMENT DIVISION

Drew Bohan
Executive Director

DISCLAIMER

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This project was the work of many people including the following:

John Avery, Director of Project Management, Geysers Power Company, LLC
Brad Backlin, Manager Mechanical Engineering, Geysers Power Company, LLC
Brian Benn, Engineering Project Manager, Geysers Power Company, LLC
Tim Conant, Director-Geothermal Engineering, Geysers Power Company, LLC
Dean Cooley, Director of Asset Management, Geysers Power Company, LLC
John Farison, Director Process Engineering, Geysers Power Company, LLC
Julio Garcia, Manager-Geothermal Production Analysis, Geysers Power Company, LLC
James Kluesener, VP Regional Operations, Geysers Power Company, LLC
Samuel Mason, Program Manager, Geysers Power Company, LLC
Leslie Morrison, Chemical Engineer, Geysers Power Company, LLC
Kevin Petersen, Plant Manager, Central Operations, Geysers Power Company, LLC
Sarah Pistone, Reservoir Engineer, Geysers Power Company, LLC
Jericho Reyes, Production Engineer, Geysers Power Company, LLC
Guy Tipton, Director Asset Management, Geysers Power Company, LLC
Karl Urbank, General Plant Manager, Geysers Power Company, LLC
Mark Walters, Senior Geologist, Geysers Power Company, LLC
Melinda Wright, Senior Geologist/Geochemist, Geysers Power Company, LLC
Alan Balzer, Program Manager, Geysers Power Company, LLC
Scott Cameron, IC&E Technician, Geysers Power Company, LLC
Brian Bastoni, IC&E Technician, Geysers Power Company, LLC
Tony Derenia, IC&E Technician, Geysers Power Company, LLC
William Tallman, IC&E Technician, Geysers Power Company, LLC

Consultants

Shaun Brady, Brady Engineering Services
Dave Cooley, Cooley & Associates
Joan Wiley, Principal Engineer, Power Engineers
Jaclyn Urbank, Mechanical/Process Engineer, Power Engineers
William Harvey, Project Engineer, Power Engineers
Mehul Patel, Mechanical Engineering Manager, Veizades Engineering
Henry Veizades, President, Veizades Engineering
Ken McIntush, President, Trimeric Corporation
Stefan Finsterle, Finsterle GeoConsulting
Michael Kowalsky, Finsterle GeoConsulting

Contractors

Nick Taylor, Owner, Dannick Mechanical
Craig Hudson, Hudson Mechanical
Carroll Mendenhall, Owner, Mendenhall Electric

Technical Advisory Committee

James Shackleford, Professor Emeritus, Mechanical Engineering Dept., UC Davis
Ken Phair, Senior Project Engineer, Global Power Solutions

PREFACE

The California Energy Commission's (CEC) Energy Research and Development Division supports energy research and development programs to spur innovation in energy efficiency, renewable energy and advanced clean generation, energy-related environmental protection, energy transmission and distribution and transportation.

In 2012, the Electric Program Investment Charge (EPIC) was established by the California Public Utilities Commission to fund public investments in research to create and advance new energy solutions, foster regional innovation and bring ideas from the lab to the marketplace. The CEC and the state's three largest investor-owned utilities—Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company—were selected to administer the EPIC funds and advance novel technologies, tools, and strategies that provide benefits to their electric ratepayers.

The CEC is committed to ensuring public participation in its research and development programs that promote greater reliability, lower costs, and increase safety for the California electric ratepayer and include:

- Providing societal benefits.
- Reducing greenhouse gas emission in the electricity sector at the lowest possible cost.
- Supporting California's loading order to meet energy needs first with energy efficiency and demand response, next with renewable energy (distributed generation and utility scale), and finally with clean, conventional electricity supply.
- Supporting low-emission vehicles and transportation.
- Providing economic development.
- Using ratepayer funds efficiently.

Investigating Flexible Generation Capabilities at the Geysers is the final report for Investigating Flexible Generation Capabilities at the Geysers (Grant Number EPC-14-002) conducted by research organization. The information from this project contributes to the Energy Research and Development Division's EPIC Program.

For more information about the Energy Research and Development Division, please visit the CEC's research website (www.energy.ca.gov/research/) or contact the CEC at ERDD@energy.ca.gov.

ABSTRACT

Electric system operators are concerned about large quantities of intermittent energy sources being reliably integrated onto the grid. While geothermal energy has served to provide a steady level of baseload energy, reducing impacts of intermittent energy will require quickly dispatchable sources of generation with the flexibility to ramp up or down as needed. Modifying geothermal operations to provide this flexibility would be valuable to system operation. However physical and operational issues are associated with providing such flexible generation from geothermal facilities.

This project conducted a study to investigate flexible electrical generation capabilities at The Geysers. The overall objective is to define steamfield and power plant operating constraints and find ways to increase flexible generating capabilities. The researchers developed an integrated numerical model to predict, study, and ultimately design strategies for flexible power generation. The modeling work performed under this project resulted in successful development and application of a simulation-optimization framework for the optimal control of a steamfield under load curtailment.

Upgrades installed during this study have removed turbine related constraints and made it feasible to achieve rapid cutbacks using existing ramp rates and provided an incremental increase in existing flexible generation capabilities. Field testing and modeling results show that steam well and pipeline corrosion is a major constraint on steam-field operations, however, results from this study will guide economic evaluations and future capital improvements needed to expand current Geysers flexible generation capabilities.

Keywords: The Geysers, geothermal, flexible generation, turbine bypass, steamfield, modeling, Hydrochloric acid-dewpoint corrosion.

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Introduction or Background

As California pursues more aggressive policies to increase renewable generation and lower overall carbon emissions from the electricity sector, a substantial amount of new intermittent renewable (non-baseload) resources are coming online. The ability of the grid to adjust to these intermittent sources is limited during the periods when the production of solar energy is the highest or when the peak wind energy is produced. Solar photovoltaic (PV) and wind electrical generation must be integrated into the existing generation system to take full advantage of the free fuel provided by sun and wind. This means that traditionally base load generation resources must collectively become more flexible by following price signals and real-time market dispatch instructions to make frequent, rapid and sometimes large load changes to accommodate the known variability of seasonal, daily hourly, generation profiles of solar PV and wind facilities. All existing generation resources, including geothermal, will need to play a role in providing this increased grid flexibility if solar and wind energy are to reach their full potential in California.

In response to these concerns, Geysers Power Company (GPC) applied for a California Energy Commission's (CEC) grant funded by Electric Program Investment Charge (EPIC), to study how the operation of its geothermal facilities at the Geysers may be modified in order to address the greater demands imposed on the grid by the significant addition of intermittent resources. Solar and wind ramp variability can far exceed the Geysers total field generation capacity. However, increasing the flexible generation capabilities of geothermal steamfields and power plants can still significantly contribute to this overall integration effort.

Geysers geothermal power plants have some significant demonstrated load following capability and are already being used to provide some load following services using existing equipment and current operating and dispatching practices. Existing flexible capabilities were investigated as part of this study. to increase geothermal based flexible capabilities by addressing limitations of geothermal steamfields and power plants that occur during load cycling and low flow conditions.

Work was suspended in September of 2015 after the devastating Valley Fire, due to the demands on GPC personnel as they supported the fire recovery effort. With the approval and support of the CEC, work began on the study again in September 2016.

Project Purpose

The primary objective of the Geysers Flexible Generation project is to investigate the constraints of The Geysers' geothermal field and identify ways to increase flexible generating capabilities of the geothermal power plants. This study has shown that Geysers geothermal resources have the potential to contribute significantly to flexible capacity of the California electrical grid. The technical and economic benefits will come from expanding the flexible generation capabilities of The Geysers generation facilities to maintain grid reliability and help support additional variable renewables to meet the state's RPS goals and avoid any significant damage to its facilities.

The detailed technical objectives of this study included the following:

- Define existing capabilities of geothermal resources at The Geysers to provide the California Independent System Operator (CAISO) with flexible generation characteristics including load following, and grid support type services
- Define limitations and operating problems that affect existing load following limits of Geysers geothermal facilities.
- Explore ways to improve flexibility in operating geothermal facilities including cyclic operation and load following through prototype development and field testing.
- Identify solutions and costs to increase the allowable operating range for load following type cyclic operation of Geysers geothermal facilities.
- Develop an integrated numerical model to predict, study, and ultimately design strategies for flexible power generation

These operating limitations must first be better understood and evaluated to define the maximum possible load changes (in terms of magnitude, frequency, duration and rate) that are achievable and mitigation methods identified and tested to avoid causing serious damage to geothermal steamfield and power plant facilities.

Project Approach

The Geysers geothermal field in northern California is the world's largest single geothermal field developed for electrical generation. The resource is vapor-dominated and generally produces dry steam. The steam is transported from the well locations through pipelines to a power plant where it spins a turbine-generator to produce baseload electricity. Fluid handling challenges include washing steam or "steam scrubbing" to remove steam impurities such as trace hydrochloric acid, hydrogen sulfide (H2S) abatement, scale deposits, corrosion, waste disposal, reservoir recharge, induced-seismicity and cyclic operations.

The primary strategy is to understand existing capabilities and limitations and upgrade facilities as needed to achieve reliable operations for ongoing load following type cyclic operations within existing operating limits.

Engineered systems and operating practices used for the current configuration of The Geysers were evaluated through modeling and field testing to identify steamfield and power plant constraints and determine ways to expand flexible generation capabilities. In order to assess steamfield constraints, the GPC resource group (staff geoscientists and engineers) established a list of parameters that could be used to quantify the potential effects due to frequent load changes or curtailments. A snapshot of normal field operating conditions was gathered to establish the base scenario from which a curtailment would take place. A set of criteria was assigned to each parameter so a recommendation could be made for curtailment assumptions.

A series of single well testing and multiple well testing were performed to observe flow, heat loss, and temperature effects during flowrate cutback. Results from these were also used to test the accuracy of the HEATLOSS program and understand the dynamic behavior of wells subjected to daily curtailment. Based on the evaluation of operating systems and steamfield constraints prototype equipment and systems were installed and tested to verify their performance for load following. Systems installed and tested included turbine bypasses, valve actuators, vortex meters and automation of desuperheat/steam scrubbing systems. The equipment and systems installed as part of this project were prototypes only and not a full implementation of the equipment required for fieldwide load following.

The project team examined simulation-optimization methods as a means to better control power generation in response to the changing demands imposed on the grid by the integration of intermittent renewable energy. To predict, study, and ultimately control flexible power generation from a geothermal field an integrated numerical framework was developed. Such a model framework consists of two main components: (1) a coupled computer model that includes reservoir, wellbore, pipeline and power plant to predict impacts from flexible generation scenarios, and (2) an algorithm that determines optimal settings of various control parameters such that the desired power curtailment is achieved without violating field constraints and power plant operating limits. A big part of the modeling effort in this project was the enhancement of GPC existing models. This included (1) modification of existing models for reservoir, wellbore, and pipeline, and power plant; (2) refinement of system components to incorporate relevant hydraulic, thermodynamic, and chemical considerations; and (3) modification of individual output models so they can be integrated into a coupled optimization framework.

GPC's staff teams met regularly to discuss operating problems and mitigation strategies and provide guidance to O&M crews for well, pipeline and power plant problems. Ongoing detailed case-by-case reviews of problem wells and pipeline operating problems are performed as needed to develop and implement specific action plans.

Throughout the term of the project, multiple geothermal industry experts and members from the technical advisory committee (TAC) representing different stakeholders, provided valuable input to the project team.

Project Results

The project has successfully demonstrated that the Geysers power plants operated by GPC can provide some increased flexible capacity as long as long as it meets its power purchase agreement (PPA) contract terms which can include penalties for not meeting generation quotas. The Geysers can provide additional cost-effective flexible capacity as long as it avoids damage to its facilities. Operating constraints for steamfield and power plant equipment have been identified that limit The Geysers current ability to operate in a more flexible generation operating mode with load reductions and frequent load changes. Key equipment was identified and tested to determine operating capabilities and limitations of equipment to achieve expanded flexible generation capabilities while avoiding or minimizing any potential damage to facilities.

An integrated numerical model was developed to predict, study, and ultimately design strategies for flexible power generation. The model consists of two main components: (1) a coupled model that includes reservoir, wellbore, pipeline and power plant and (2) an algorithm that determines optimal settings of various control parameters such that the desired power curtailment is achieved without violating operational constraints.

Field and prototype testing was instrumental in model validation and calibration. Field testing was also used to refine the assumptions for field constraints and control parameters to formulate a well-posed optimization problem. Field wide model runs indicate that curtailment of about 65% of GPC Geysers current baseload levels down to production levels close to existing CAISO dispatch minimum MW can be achieved temporarily without violating well and steam field constraints.

Results from this study will guide economic evaluations and future capital improvements needed to expand current Geysers flexible generation capabilities.

Flexible ramp contributions will be needed from many generators. The magnitude of flexible ramp needed to accommodate variable energy resources (VER) far exceeds the total generation of the Geysers geothermal field.

Technology/Knowledge Transfer/Market Adoption (Advancing the Research to Market)

Results of this study was published in the Geothermal Resources Council (GRC) Bulletin to inform design decisions and cost/benefit evaluations for capital upgrades needed to expand flexible generating capabilities at The Geysers.

More technology transfer will occur through the publication of the final report and through future technical papers and presentations of selected results from the study at the Geothermal Resources Council annual conference and at other technical conference venues.

Results of this study will be available to other geothermal operators that may be facing similar technical challenges in increasing their flexible generating capabilities.

Benefits to California

This project will provide economic benefits to California ratepayers by incrementally expanding the flexible generation capabilities of the Geysers generation facilities to maintain grid reliability and help support additional variable renewables to meet the state's RPS goals. Information from this study will guide future modifications of Geysers systems as needed to expand current flexible generation capabilities.

The technical and economic benefits of this study will come from maintaining the historic reliability of Geysers geothermal generation with the challenging impacts of more frequent load fluctuations. An added benefit comes from achieving incremental increased flexible generation capabilities by expanding the operating range to lower minimum loads. Expanded load following operations will provide economic incentives if risks can be managed and damage to steamfield and power plant facilities largely avoided.

CHAPTER 1: Introduction

Investigating Flexible Generation Capabilities

As California advances towards achieving its goal of increased use of renewable electrical energy, the state's electric grid is changing as a substantial amount of new, variable renewable resources such as solar and wind come online. The ability of the grid to adjust to these intermittent sources is limited during the periods when the production of solar energy is the highest or when the peak wind energy is produced. Because of this grid limitation, increased flexibility is needed from other generation sources on the grid.

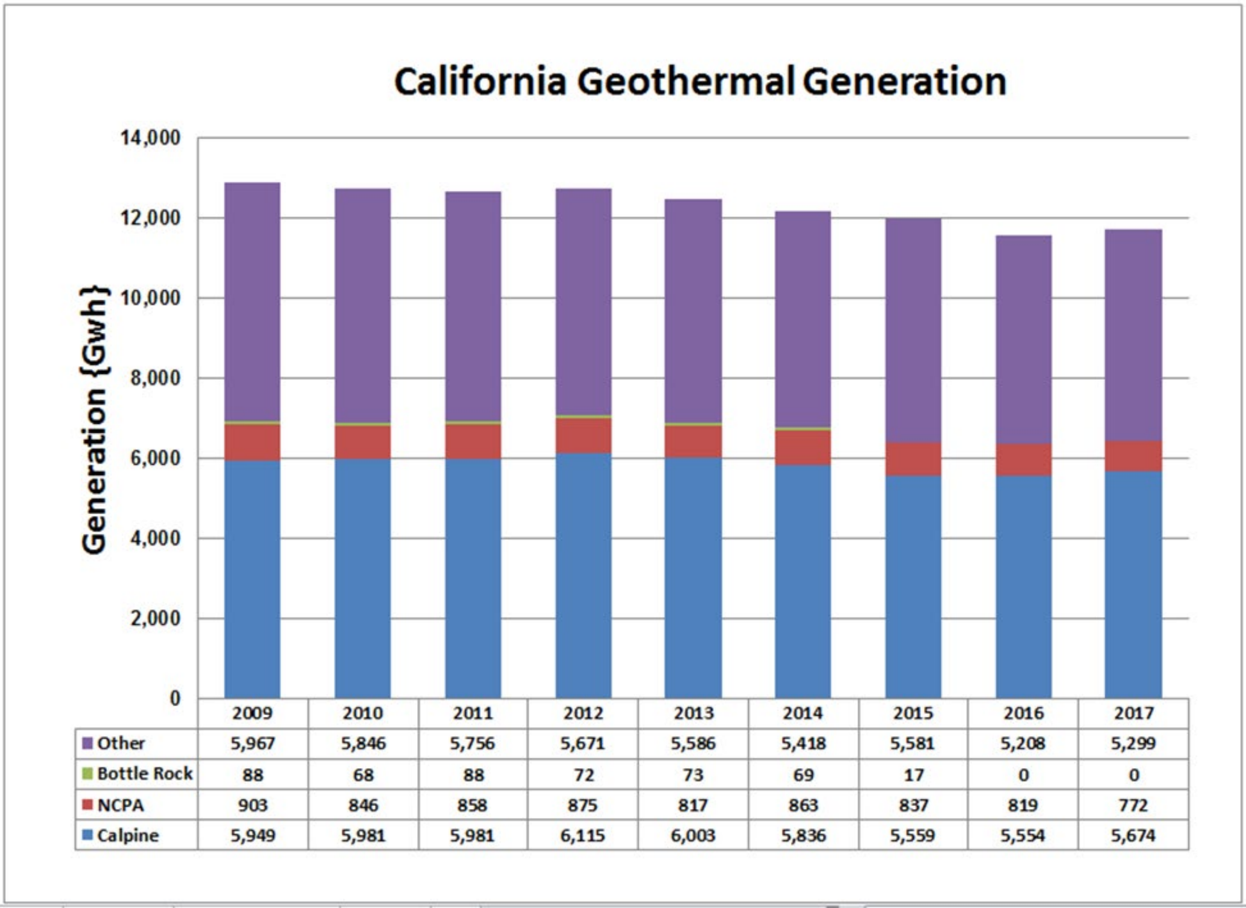
In July of 2014, GPC applied for a grant to help support this study under California Energy Commission (CEC) Program Opportunity Notice PON-13-303. This grant is funded by the Electric Program Investment Charge (EPIC)to investigate flexible generating capabilities of geothermal steamfield and generation facilities and identify modifications or changes in operating practices that may be needed to increase its flexible generating capabilities. Adjusting operations and procedures to become more flexible will produce physical and operational challenges. Adjusting operations and procedures to become more flexible will produce physical and operational challenges. This study has advanced GPC's understanding of the range of operating scenarios that can be reliably dispatched, as well as the associated costs, risks and effects to the physical operation of the above-ground facilities and the geothermal reservoir.

Geysers Overview

Geysers Power Company, LLC, LLC (GPC) is the largest producer of geothermal energy in the United States and is committed to developing technologies and processes that will improve the ability of its facilities to respond to changing demands in the California electrical generation market. GPC is a wholly owned subsidiary of Calpine Corporation and owns The Geysers generating assets that are operated by Calpine Operating Services Company. GPC's Geysers facilities have provided a reliable source of renewable, low-carbon, baseload geothermal energy for 57 years.

These facilities produce up to approximately 10% of California's renewable electrical energy, using 327 production wells, about 80 miles of steam pipelines, and 52 water injection wells. Plant condensate is augmented by up to 20 million gallons per day of treated wastewater from Sonoma and Lake Counties to keep the reservoir charged. Figure 1 shows the annual generation from GPC's Geysers power plants, while Figure 2 illustrates a summary of Geysers field statistics.

Figure 1: California and Geysers Annual Generation Overview



Source: Geysers Power Company, LLC

Figure 2: GPC's Geysers Field Statistics – August 2018

STATISTICS

The Geysers by the Numbers

The Geysers Geothermal Field 2017 Statistics

The Geysers – 15 Power Plants (Calpline & NCPA)
- 75 miles north of San Francisco, California
- 12 power plants in Sonoma County (10 Calpine, 2 Northern California Power Agency)
- 3 Calpine power plants in Lake County

Calpine Geothermal Operations
- 29,000 acres (45 square miles)

Geothermal Wells
- 322 steam wells
- 54 injection wells
- Deepest well: 12,900 feet, or over two miles
- Average well depth: 8,500 feet
- Total Calpine Geysers wells drilled to date: 591
- Today's average grass-roots drilling time: 85 days (75 days drilling + 10 rig up/down)
- First exploratory well: 1920
- First modern well: 1955
- 2017 average steam production per well: 36,036 pounds per hour
- Average reservoir steam temperature: 374 degrees Farhenheit
- Average flowing steam pressure: 82 PSIG
- Most recent steam well drilled: Prati 31, January 2017
- Most recent injection well drilled: CMH8, May 11, 2017

Facilities
- 13 geothermal plants
- Steam pipelines: 80 miles
- Injection water lines: 69 miles
- 21kV power lines: 70 miles
- Project roads: over 167 miles

Water Injection
- Two large-scale wastewater injection projects provide an average 15.09 million gallons daily (MGD)
  - Santa Rosa Geysers Recharge Project average: 11.69 MGD
  - Calpine Southeast Geysers Effluent Pipeline average: 3.4 MGD
  - Calpine + Northern California Power Agency: 7 MGD

Power Generation
- First commercial power plant: Unit 1, Startup - September 1960
- Most recent plant built: Aidlin, 1989
- 2017 average output: 647.7 net megawatts
- 2017 generation: 5,673,647 net megawatt hours
- 2017 average unit availability: 94%

Visit The Geysers
- Visit: The Calpine Geothermal Visitors Center in Middletown, California, Wednesdays through Saturdays from 11:30 a.m. to 5 p.m. (admission is free)
- Tour: Sign up for a free geothermal power plant tour led by an experienced Calpine team member by visiting www.geysers.com or calling 1-866-GEYSERS or 707-987-4270.

CALPINE®

Calpine at The Geysers

Calpine Corporation is America's largest generator of electricity from natural gas and geothermal resources with operations in competitive power markets. Our fleet of 79 power plants in operation or under construction represents approximately 26,000 megawatts of generation capacity. Through wholesale power operations and our retail businesses Calpine Energy Solutions and Champion Energy, we serve customers in 24 states, Canada and Mexico. Our clean, efficient, modern and flexible fleet uses advanced technologies to generate power in a low-carbon and environmentally responsible manner. We are uniquely positioned to benefit from the secular trends affecting our industry, including the abundant and affordable supply of clean natural gas, environmental regulation, aging power generation infrastructure and the increasing need for dispatchable power plants to successfully integrate intermittent renewables into the grid. Please visit www.calpine.com to learn more about how Calpine is creating power for a sustainable future.

www.calpine.com

www.geysers.com

August 2018

Source: Geysers Power Company, LLC

Fluid Handling Challenges at The Geysers Geothermal Field

The Geysers geothermal field in northern California is the world's largest single geothermal field developed for electrical generation. The resource is vapor-dominated and produces dry steam. Dry steam is transported through pipelines to a power plant where it spins a turbine-generator to produce baseload electricity. The steamfields include a sprawling network of pipelines, interconnected power plants, chemical process systems, and fluid handling challenges. Fluid handling challenges include steam scrubbing, H2S abatement, scale deposits, corrosion, waste disposal, reservoir recharge, induced-seismicity and cyclic operations.

Geysers steam composition and steam condition

The Geysers steam is generally superheated at the wellhead at maximum flowrates. The "steam condition" defined by temperature, pressure, wetness or superheat and varies across the field and with time in each steam well. The pipeline steam condition and composition are the weighted average of the combined flows in the pipelines. Non-condensible gas (NCG) composition and concentrations vary with location in the field and change over time. The main impurities in Geysers steam are non-condensible gases: CO2, H2S, NH3, H2, CH4, N2. There are also trace volatile species: boric acid, Hydrochloric, Ar, Hg. Annual fieldwide chemical surveys are conducted to sample all steam wells and pipeline steam as it enters the power plants. Changes in steam chemistry are monitored and tracked. The steam chemistry changes as wells are cutback, or if steam wells are added or subtracted from the combined flows. This complexity lends itself to computer modeling.

Power plant H2S Abatement Systems

Each power plant at The Geysers has an H2S abatement system, either a Stretford system or a Burner-Scrubber system. The Stretford system produces a sulfur cake that is hauled off and used as a soil supplement. The Burner system converts the H2S into soluble sulfur species that are reinjected into the steam reservoir with excess condensate from the cooling towers. Each power plant has its own H2S abatement system operating permit and H2S emission limit. If the chemical abatement system shuts down then the power plant must be curtailed or shutdown to meet its permit requirements.

Crossover pipelines interconnect adjacent power plant steamfields. Wells located between adjacent steamfield areas have valving that allow wells to be routed to a specific unit or all valves between adjacent areas may be kept open to allow steam to "float" between areas and seek the lowest pressure path to maximize steam flowrates and generation. Sudden large shifts of steam with different gas concentrations to an adjacent power plant may create process chemistry transients in inlet steam NCG concentrations that may overload a power plant H2S abatement system.

Current Operational Configuration of The Geysers

A summary of the current operational configuration of the Geysers is outlined below:

- Geysers power plants owned and operated by GPC/Calpine are the major generation facilities for the North Coast/North Bay Area region of the CAISO operated grid.
- Geysers renewable generation is contracted by utilities (for example PG&E, SCE) and other LSE's (Load Serving Entities) to meet their RPS annual renewable MWh quotas.

- The Geysers and solar PV provide 100% renewable generation in this region on an annual net generation basis. Installation of large amounts of additional solar PV may run into distribution line limits.
- The Geysers generation feeds three sub stations: Fulton, Eagle Rock, Lakeville
- Interconnected steam pipeline network. Steam shifted between units routinely as needed for power plant outages, curtailments and overhauls to avoid vented steam and H2S emissions.
- The Geysers has very high availability and low EFOR (effective forced outage rate) when operated as baseloaded units
- Geysers power plants are designated as Resource Adequacy units for grid reliability and must bid into the CAISO markets and be available to generate.
- Some Geysers power plants are periodically curtailed down to their current P-min.
- Daily voltage support and scheduled reactive power supplied to local grid Sub Areas

Geysers Key Power Plant Parameters

GPC operates 13 power plants at The Geysers. Key operating parameters for Geysers power plants are listed in Table 1. The power plants are grouped on the table according to the transmission line connections.

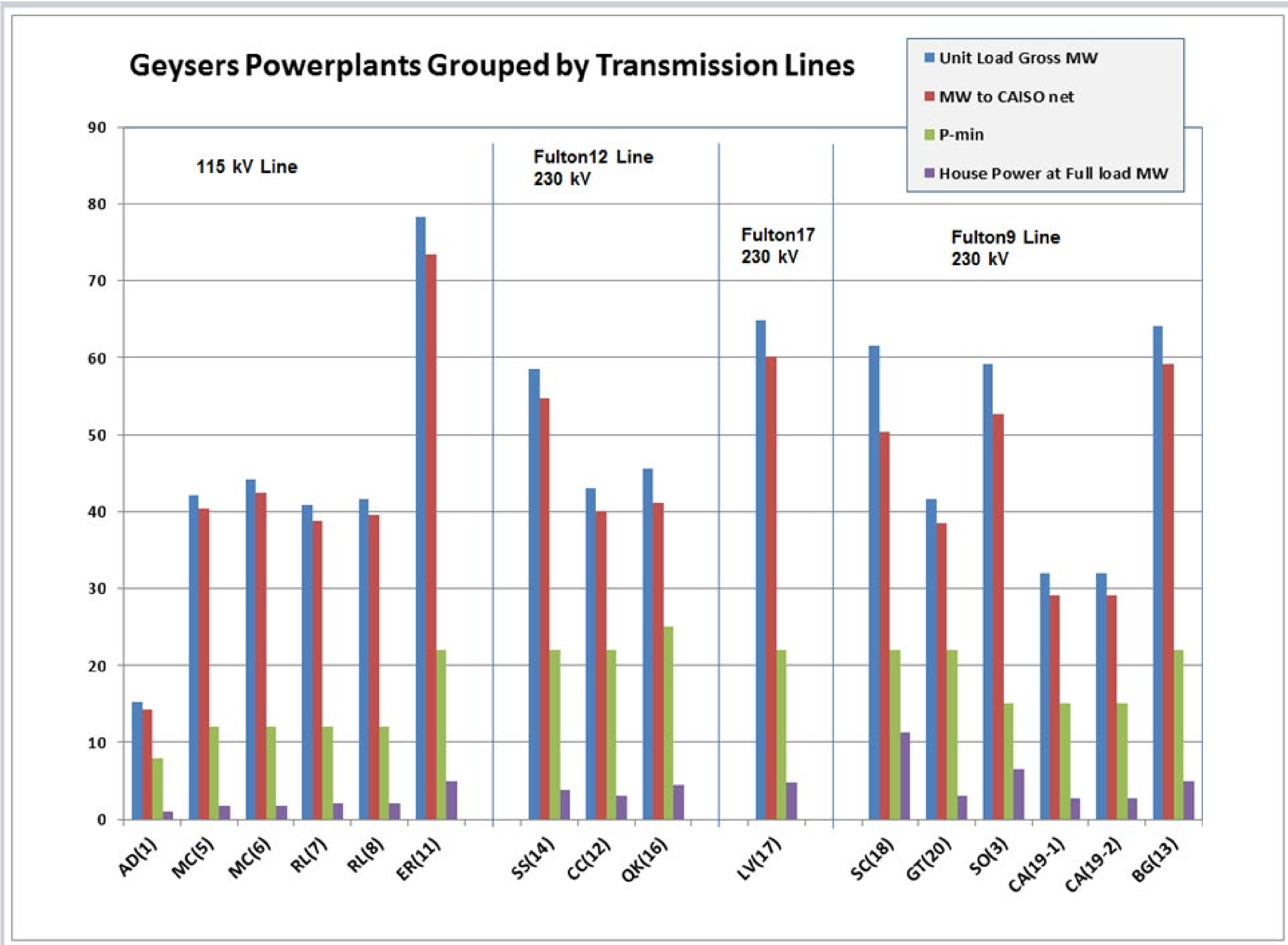
P-max and P-min values are the CAISO dispatch operating limits in MW for each power plant. A power plant may be able to operate outside of this range, for example below the P-min value but CAISO will not send dispatch instructions outside of this range.

Geysers Power plant Nominal Load, P-min and House Power

A comparison of Geysers power plants nominal full available load, P-min minimum dispatch load and house power are shown in Figure 3. The power plants are grouped by the transmission line connections that serve the power plants.

- There are six turbine-generators on the 115 kV line to Eagle Rock substation.
- There are three GPC power plants on the 230 kV "Fulton 12 Line".
- There are six GPC power plants on the 230 kV "Fulton 9 Line".

Figure 3: Geysers Power Plant Loads Comparison



Source: Geysers Power Company, LLC

Table 1: Key Parameters Affecting Flexible Generation Capabilities

Powerplant Name	Unit	P-MAX MW	CAISO dispatch P-MIN MW	CAISO Max Ramp Rate MW/min	Output Voltage	North Coast North Bay Transmission Line	Voltage Support & Reactive Power?	Super Rotor Installed?	Upgraded Powerplant DCS	Runback to House Power Capability?	Turbine Bypass Installed	Hotwell Water Supply for Steam Scrubbing	21 kV Supply to Geysers Distribution	H2S Abatement System Installed	Comments
Notes ->			a				b	c		d	e	f	g	h	
Sonoma	SO 03	53	15	3	230kV	Lakeville9	YES	YES	YES	YES	YES	YES	YES 2 MW	Stretford	Primary hotwell scrub water supply unit
Big Geysers	BG 13	95	22	2	230kV	Lakeville9	YES	YES	YES					Stretford	
Socrates	SC 18	72	22	2	230kV	Lakeville9	YES	YES	YES				YES 6.6 MW	Stretford	
Calistoga	CA 19	92.1	30	2	230kV	Lakeville9	YES	YES	YES	YES	YES			Stretford	
Grant	GT 20	62	22	2	230kV	Lakeville9	YES	YES	YES					Stretford	
Lakeview	LV 17	60	22	2	230kV	Fulton17	YES	YES	YES			YES	YES	Stretford	Primary hotwell scrub water supply unit
Sulfur Springs	SS 14	70	22	2	230kV	Fulton12	YES	YES	YES					Stretford	
Quicksilver	QK 16	85	25	2	230kV	Fulton12	YES	--	YES		YES		YES	Stretford	
Cobb Creek	CC 12	57	22	2	230kV	Fulton12	YES	YES	YES					Burner	
McCabe	MC 5/6	85	24	4	115kV	Eagle Rock	YES	YES	YES					Burner	
Ridgeline	RL 7/8	82	24	4	115kV	Eagle Rock	YES	YES	Q2 2019					Burner	
Eagle Rock	ER 11	74.4	22	2	115kV	Eagle Rock	YES	YES	2021					Burner	
Aidlin	AD 01	22	8	2	115kV	Eagle Rock	YES	--	YES	YES	YES			Burner	Isolated geographically. No steam crossovers
			280	31											

Notes:

a P-min is the minimum dispatch powerplant load on file with the CA-ISO

b All Geysers units provide daily reactive power and voltage support following the schedule from PG&E’s Fulton substation

c Super rotors allow turbines to run at house load. Older turbines have minimum load requirements due to vibration issues

d Powerplant control system allows runback to house power on selected units

e Turbine bypasses on U1, U3, U16, U19. New turbine bypasses are being installed on U5 and U17 as part of the CEC grant project

f A continuous supply of hotwell water (oxygen-free steam condensate) is needed for steam scrubbing systems across the Geysers

g steamfield facilities (pumps, motors, lighting, instrumentation) are powered by our internal 21 kV distribution system

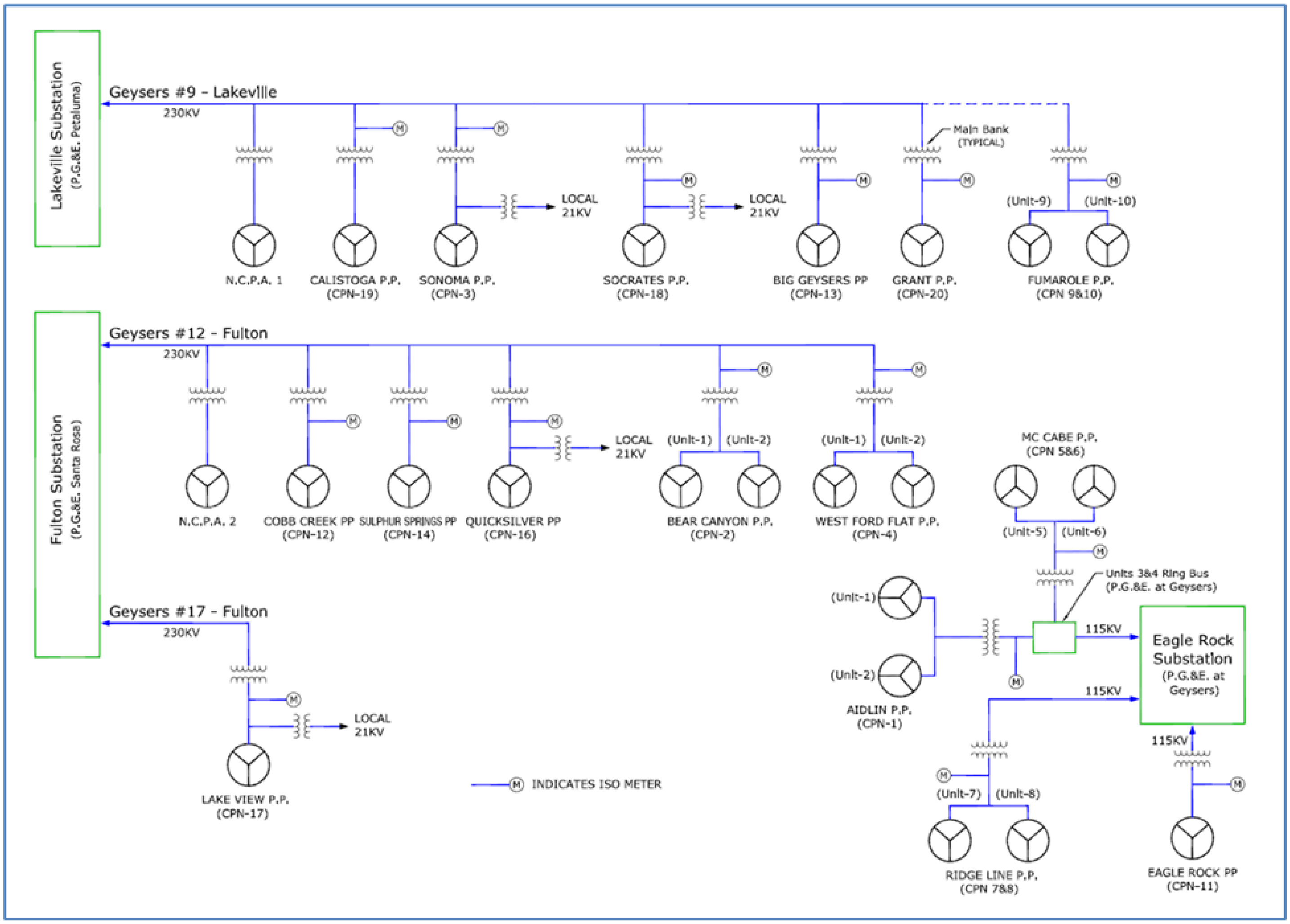
h Each powerplant has an H2S abatement system. Emission limits for H2S must be met at all times for the powerplant to operate

Source: Geysers Power Company, LLC

Transmission Lines for Geysers Generation

The Geysers power plants operated by GPC are connected to the California electrical grid through transmission lines owned and operated by PG&E. Geysers generation supplies the North Coast / North Bay Area of CAISO controlled grid. The substations supplied from The Geysers are 1) Fulton Substation, 230kV; 2) Lakeville Substation, 230kV and 3) Eagle Rock Substation, 115kV as shown in Figure 4.

Figure 4: Geysers power plants, transmission lines and substations



Source: Geysers Power Company, LLC

Expanding Geysers Geothermal Load Following Limits

Solar and wind electrical generation must be integrated into the existing generation system to take full advantage of the free fuel provided by sun and wind. This means that other generation resources must collectively become more flexible by following price signals and real-time market dispatch instructions to make frequent, rapid and sometimes large load changes to accommodate the known variability of seasonal, daily hourly, generation profiles of solar and wind facilities.

Solar and wind ramp variability can far exceed the Geysers total field generation capacity. All existing generation resources, including geothermal, will need to play a role in providing this increased grid flexibility if solar and wind energy are to reach their full potential in California.

Geysers geothermal power plants have some significant demonstrated load following capability and are already being used to provide some load following services using existing equipment and current operating and dispatching practices. Existing flexible capabilities were investigated as part of this study.

However, it may be possible to increase geothermal based flexible capabilities by addressing limitations of geothermal steamfields and power plants that occur during load cycling and low flow conditions.

These operating limitations must first be better understood and evaluated to define the maximum possible load changes (in terms of magnitude, frequency, duration and rate) that are achievable and mitigation methods identified and tested to avoid causing serious damage to geothermal steamfield and power plant facilities.

Existing Geothermal Flexible Capabilities

Geothermal steamfields and power plants at the Geysers are considered as baseload generation. However, geothermal power plants have significant demonstrated capability to change loads for load following as will be explained here.

The Geysers power plants participate in CAISO markets and receive a daily day-ahead generation dispatch schedule from CAISO that often includes numerous hourly load changes. On top of these day-ahead scheduled hourly loads there are often numerous real-time dispatch orders that are updated every 5-minutes to make incremental load increases or decreases. For example, numerous short term daily generation cutbacks have been dispatched on power plants feeding the 115 KV Eagle Rock transmission line to handle periodic congestion on this transmission line.

Geothermal generation is scheduled in the California ISO day ahead and real-time markets and geothermal power plant operators routinely respond to ISO 5-minute dispatch orders received at GPC's Central Operations to change load on short notice.

Geysers geothermal power plants operated by GPC have nominal ramp rates of 2 to 4 MW per minute up or down and have demonstrated ramp rates much faster than this. Although these capabilities can be broadly considered as ancillary services to grid operations they are not recognized or compensated as such in the market. Regardless of which market segment geothermal generation is bid into and scheduled, CAISO takes advantage of these capabilities provided by geothermal generators on a daily basis.

Voltage Support and Reactive Power

An important grid support service provided by Geysers geothermal power plants is voltage support and reactive power support. Reactive power "VARs" are delivered into the system during morning ramp up and absorbed at night during the ramp down. The Geysers power plants with their synchronous generators are the major generation facilities for the North Bay region of the transmission grid and routinely provides voltage and reactive power service to the grid without any direct compensation to GPC for this ancillary service.

Some limited load cycling now occurs on Geysers power plants and some large scale fieldwide cutbacks over 200 MW have periodically occurred with some significant but manageable steamfield and power plant operating problems.

Previous Geysers Load Curtailments are No Guide for Today

Some large daily load cycling from full nameplate generating capacity down to 50% load has occurred in the past at The Geysers in the 1980's and 1990's. For example, daily curtailments of about 50% from design maximum load were once performed on all Geysers power plants due to availability of excess hydropower during high snowmelt runoff years by PG&E back in the period 1995-1998.

Steamfield operators were very concerned about potential damage to steam wells and steamfield facilities due to daily load cycling and some damage to steam wells was observed. Cutback minimum power plant loads and ramp rates for each power plant were established through discussions and negotiations between steamfield and power plant operators, prior to 1999 when steamfield and power plant facilities were owned and operated by separate companies. Daily hydro related curtailments of Geysers power plants have not occurred since that time frame.

Today's current Geysers power plant generating levels are far below original nameplate. Operating steam temperature and pressures and steam chemistry have dramatically changed. Therefore, previous load cycling is not a good guide for today's operating conditions.

The CAISO did not exist when hydro-curtailments occurred in the past. All Geysers generation bidding, load scheduling are based on economics and competing in the CAISO electrical generation markets.

Becoming more flexible in terms of managing physical constraints in wells, pipelines, and operating systems in steamfields and power plants is essential for expanded load following and flexible generation.

Changing Conditions Warrant a Re-evaluation of Operating Limits

Geysers steamfields and power plants have changed over time including:

- Operating at lower than design pipeline pressures and flowrates, and velocities
- Operating at lower turbine inlet pressures and lower turbine exhaust pressures
- Increased number of wells with high acid-chloride that required continuous scrubbing
- Large changes in non-condensible gas loading due to injection effects
- Continuous desuperheating/steam scrubbing systems added on most Geysers units
- Large scale injection of treated wastewater (SEGEP and SRGRP)
- Optimization of steamfield and power plant facilities under one ownership
- Effects of deregulation and industry consolidation since 1999

California's electrical generation landscape has also changed including:

- Creation of the CAISO day-ahead and real-time generation marketplace
- Increased demand for renewable energy from all sources
- Large increased generation capacity of solar and wind facilities

Geothermal operating limits need to be continually reevaluated and updated in light of these changes.

Modeling Effort

Simulation techniques have been an integral part of reservoir assessment and management at the Geysers geothermal field since the mid-1980s. GPC currently uses a numerical simulator that consists of three different components (reservoir, pipeline network, and power plant interface model) coupled together.

A key part of the modeling effort in this project was the enhancement of GPC existing models. This included (1) modification of existing models for reservoir, wellbore, and pipeline simulation, (2) refinement of system components to incorporate relevant hydraulic, thermodynamic, and chemical considerations, and (3) modification of individual output models so they can be integrated into a coupled modeling environment. Load curtailment modeling performed during this project included well, steamfield constraints and power plant operating limits.

Steam well constraints include maintaining minimum superheat to avoid HCl acid-dewpoint corrosion in wellbores and pipelines, and avoiding deep flowrate cutbacks on "no touch" wells with other constraint requirements (unstable formation, casing or mechanical problems). Pipeline constraints include maintaining minimum flows in the steam piping network to avoid buildup of non-condensible gas pockets that can trip power plants.

Details of incorporation of the integrated simulation model with suitable algorithms for optimization of operations controls without violating operating conditions described in (Chapter 2).

CHAPTER 2: Project Approach

Modeling Flexible Generation at The Geysers

The scope of work for the modeling effort was divided in five areas of work: (1) Evaluation of analytic and simulation models, (2) System component modeling, (3) Model integration, (4) Modeling Framework Validation and (5) field wide application and optimization.

Evaluation of Analytic and Simulation Models

Project team evaluated the suitability of other simulation tools for individual system components for use within a larger modeling framework intended for reservoir management. Details of this analysis was documented in the Integrated Model Report (Appendix 1).

The project examined simulation-optimization methods as a means to better control power generation in response to the changing demands imposed on the grid by the integration of intermittent renewable energy. Requests for deeper and more frequent curtailments call for operating adjustments that are challenging due to the complexity of the interconnection and interactions between the reservoir, injection and production wells, the pipeline system, and power plants. Each of these elements has its own optimal operating conditions as well as constraints that cannot be violated without risking temporary or permanent shutdowns or physical damage and thus substantial economic loss. To predict, study, and ultimately control flexible power generation from a geothermal field an integrated numerical framework was developed. Such a model framework consists of two main components:

(1) A simulation program that predicts the impacts of rapidly changing fluid production on the geothermal reservoir, wells, pipelines, and ultimately the net production of the power plant.

(2) An algorithm that determines optimal settings of various control parameters such that the desired power curtailment is achieved without violating operational constraints.

The integration of these two components in a robust and efficient manner accomplished during this project provides a useful decision-support tool for geothermal operators to examine and design long-term exploitation strategies as well as to control and optimize adjustments made to the steamfield above-ground system (SAGS).

The general approach can be described as follows:

1. Select, adapt, or develop an appropriate simulation code for the prediction of geothermal power production under changed reservoir and operational conditions.
2. Compile a list of control parameters that may be adjusted to reduce or increase net power production. These control parameters must be input parameters to the simulation model.
3. Compile a list of simulator output variables that can be used as performance measures for successful curtailment. The total net power production may be used as the ultimate optimization target.

4. Compile a list of constraints that need to be obeyed. Constraints may be related to the control parameters (i.e., input variables) or to specific predicted system responses (i.e., output variables) or a combination thereof.
5. Formulate an objective function that includes one or multiple optimization targets.
6. Select, adapt, or develop an optimization algorithm capable of minimizing a nonlinear objective function under a variety of constraints on both input parameters and output variables.
7. Demonstrate that the simulation-optimization framework is capable of finding an optimal solution to the power adjustment problem without violating the imposed constraints for a generic, simplified subsystem and scenario.

Geysers Steamfield and Power Plant Constraints

The Geysers geothermal field in northern California is the world's largest single geothermal field developed for electrical generation. The resource is vapor-dominated and generally produces dry steam. The steam is transported from the well locations through pipelines to a power plant where it spins a turbine-generator to produce baseload electricity. Fluid handling challenges include washing steam or "steam scrubbing" to remove steam impurities such as trace hydrochloric acid, hydrogen sulfide (H2S) abatement, scale deposits, corrosion, waste disposal, reservoir recharge, induced-seismicity and cyclic operations.

The primary strategy is to understand existing capabilities and limitations and upgrade facilities as needed to achieve reliable operations for ongoing load following type cyclic operations within existing operating limits.

Engineered systems and operating practices used for the current configuration of The Geysers were evaluated through modeling and field testing to identify steamfield and power plant constraints and determine ways to expand flexible generation capabilities. In order to assess steamfield constraints, the GPC resource group (staff geoscientists and engineers) established a list of parameters that could be used to quantify the potential effects due to frequent load changes or curtailments. A snapshot of normal field operating conditions was gathered to establish the base scenario from which a curtailment would take place. A set of criteria was assigned to each parameter so a recommendation could be made for curtailment assumptions.

A series of single well testing and multiple well testing were performed to observe flow, heat loss, and temperature effects during flowrate cutback. Results from these were also used to test the accuracy of the HEATLOSS program and understand the dynamic behavior of wells subjected to daily curtailment. Based on the evaluation of operating systems and steamfield constraints prototype equipment and systems were installed and tested to verify their performance for load following. Systems installed and tested included turbine bypasses, valve actuators, vortex meters and automation of desuperheat/steam scrubbing systems. The equipment and systems installed as part of this project were prototypes only and not a full implementation of the equipment required for fieldwide load following.

The project team examined simulation-optimization methods as a means to better control power generation in response to the changing demands imposed on the grid by the integration of intermittent renewable energy. To predict, study, and ultimately control flexible power generation from a geothermal field an integrated numerical framework was developed. Such a model framework consists of two main components: (1) a coupled computer model that includes reservoir, wellbore, pipeline and power plant to predict impacts from flexible generation scenarios, and (2) an algorithm that determines optimal settings of various control parameters such that the desired power curtailment is achieved without violating field constraints and power plant operating limits. A big part of the modeling effort in this project was the enhancement of GPC existing models. This included (1) modification of existing models for reservoir, wellbore, and pipeline, and power plant; (2) refinement of system components to incorporate relevant hydraulic, thermodynamic, and chemical considerations; and (3) modification of individual output models so they can be integrated into a coupled optimization framework.

Steamfield Impacts from Load Following

GPC staff geoscientists and engineers identified and evaluated steamfield constraints as listed in Figure 5 that could cause potential damage to facilities from load cycling or curtailments.

Figure 5: Potential Steamfield Constraints to Load Cycling

'Do Not Touch'	**Chloride**	overlap w/ corrosion.
'Do Not Touch'	**Unstable Formation/ Bridge Bust Wells**	
'Do Not Touch'	**Known Casing Problems**	
'Do Not Touch'	**Injection Breakthrough**	keep wells suffering from breakthrough flowing, i.e. 'do not touch' *list of breakthrough wells (DV-23, DX-42, AID-6) *quarterly monitoring to keep list updated *watch list for former breakthrough wells to monitor *wells that make water/have seperators put on watch list
Flow Cutbak Limits	**High Concentration of Gases**	OF48A-2 6% gas gas build-up risk (rate of gas cap formation) min flow to prevent condensation, which would increase gas condensation NCG data at plant during curtailments may inform parts of field that are risk of higher gas shut-in wells need to consider venting requirements
Flow Cutbak Limits	**Condensation**	**wellbore:** start w/ U20 & U14 Superheat at depth total heatloss (btu/hr) heatloss by FR (btu/lb) **pipeline:**
Flow Cutbak Limits	**Corrosion**	categorize wells according to volatile Chloride (HCl) and superheated steam **Chloride types:** *high-acid wells (>14ppmw HCl) *mod-acid wells (5-14ppmw HCl) mix w/ low-acid wells, keep above certain deg superheat *low-acid wells (0-5 ppmw), <0.150 ppmw is target for steam entering plant "Allowable" corrosion rate 5-10mpy (approx linear CR = 12.4*HCl, ppmw); acceptable pipe life **Superheat:** >60deg SH is "safe"; related to dew point of HCL = f(SH) low flow/low SH/high HCl --> high Risk consider mixing points (can either improve or worsen conditions) **SH/HCl Profile:** wt-ave HCl & SH as pipelines/wellpads converge towards plant
Flow Cutbak Limits	**Injection Influence**	Highest tracer concentration returns (tracer reports) Highest difference in NCG rates (geochem database) Highest change in flow response (inj groups) Seismic relationships
Flow Cutbak Limits	**Steam Gathering System**	**at Wellhead** **RC plugging problems:** review daily PTF reports, Melinda notes **Actuators:** survey functioning actuators and/or search maximo for broken actuators. John F list given to Bud/Harold **maxWHP:** review well deliverability for pressure at which flow would be supressed. Validate deliverability. **at X-Overs** **low flow:** evaluate configurations that reduce/reverse flow **ctrl vlvs:** new valves for flexibility

Source: Geysers Power Company, LLC

A summary of potential operational impacts from daily load cycling is provided in Table 2.

Table 2: Potential Operational Impacts of Load Cycling – Steamfields and Powerplants

Wells & Steam Field	**Expected Effects**	**Potential Costs**	**Mitigation Steps**	**Examples**
Pipeline and wellbore corrosion	Daily thermal cycling of steam wells and pipelines will contribute to loosening of stable corrosion product layers and scale deposits and increased corrosion "wear and tear".	Difficult to quantify. Expect largest effects in Units 5/6, 7/8, and 11 steamfields with highest HCl and gas contents.	Use strategy of spreading out the effects over more wells instead of larger cutbacks on fewer wells. Identify problem wells and create new well cutback lists for each unit area.	
Steam Well and Pipeline Control Systems	Steam well throttling valves will become critical components. Inoperative AUMA actuators and throttling valves will need to be repaired/replaced.	Deferred maintenance costs incurred to get valves and AUMAs fully operational again.	Repair/replace AUMAs as needed. Add strategic MOV's in the steamfield to facilitate remote cutbacks and crossovers.	Review/update current A1 & A2 AUMA maintenance list.
High Chloride and High Superheat Wells	Drop in superheat occurs when pipeline pressure goes up. Potential for corrosive conditions at point of initial condensation. May create corrosive conditions downhole and cause wall loss in exposed casing section.	Potential for increased steam leak repairs. Could lead to multiple wellhead repair jobs at ~100k/repair.	Minimize cutbacks on high HCl wells. Monitor wellhead temperature and superheat on high HCl wells.	Provide list of high HCl wells and flowing WH superheat for both A1 & A2.
Corrosion Mitigation Facility Wells	Wellhead pressure will rise on CMF wells by about 20 psi suppressing the flowrate by about 5 kph each. Superheat will drop by about 8 deg SH on each well. Less DP available for spray nozzles will reduce CMF inj rate.	As long as sufficient superheat maintained at wellhead then no change expected. If superheat drops at wellhead, this could lead to the need for high allow casing at $3m.	Transient conditions minimized by keeping CMF wells at 100% throttle valve. Monitor CMF performance to identify any problems and address as needed.	2507 alloy casing to 4000' installed in PS-31 for $3m.
High NCG Wells	Cycling high Non-Condensible Gas (NCG) wells daily can cause gas loading to change as wells feed from different stream entries.	Sudden changes in gas loading would cause a slug of gas and potential trip of a power plant or abatement system.	Avoid maximum cutbacks on high gas wells.	Ottoboni Ridge high gas wells.
Wellbore Instability	Frequent cycling of steam wells will introduce wellbore pressure and temperature changes and possible wellbore condensation. Formations sensitive to water may be affected. Especially deep wells in Argillite without slotted liners.	Potential for wellbore damage and well workover costs.	Geologists to identify cutback & water sensitive wells and avoid large cutbacks to minimize the differential temperature and pressure range of thermal cycling.	42 out of 333 steam wells have slotted CS production liners in the steam zone.
Desuperheat Systems	Load changes raise line pressure, reduce flow and steam SH, and create upset condition in heat and mass balance of DSHT systems. Pipeline pressure changes affect nozzle DP and injection rates.	Flex DSHT needed to automate valves and dynamic injection rate setpoint needed for real-time heat balance. $160k to $200k per DSHT system.	Monitoring by Central Ops and adjustments to injection rate setpoints as needed. Review DSHT system guidelines for covering cutback conditions.	U13 and U3 prototype Flex DSHT upgrades for $160k.
Vent Gathering Systems	Increase in condensate production during cutbacks. May observe increased solids at KP's. Potential for water hammer if KP's fail to remove condensate. May see increased corrosion at KP's.	Knockout pots (KP) are already a high maintenance cost item. ~1000 KP's in the field.	Normal O&M maintenance. No significant changes. This is what the KP's and vent lines were designed to handle. Thickness monitoring needed for safety.	
Well Venting	High NCG wells may load up if cut back too far. May lead to gas slug going to power plant.	Increased operator attention required to monitor and adjust vent gathering systems.	Avoid maximum cutbacks on high gas wells.	
Geochemical Monitoring	Non-baseload operation will introduce geochemical transients which will mask long term trends.	Reduced confidence in predicting geochemical trends.	Reschedule field wide surveys to occur during baseload stabilized periods if possible.	
Power Plants	**Expected Effects**	**Potential Costs**	**Mitigation Steps**	**Examples**
Burner H2S Abatement Systems	Vent gas flow will suddenly drop. May create upset condition in powerplant abatement systems. Frequent well cycling will add instability to vent gas trends.	Increased on-site plant operator attention required to monitor and adjust the H2S abatement systems.	Monitor effects of cutbacks and adjust as needed.	Unit 11 Burner
Monthly Source Tests	Monthly emissions source tests required for compliance with air permits. Source test must occur during full load operations.	Difficulty in scheduling a day with no load changes. Costs TBD.	TBD	

Wells & Steam Field	Expected Effects	Potential Costs	Mitigation Steps	Examples
Ejector motive steam	Pipeline pressures will rise at plants as governor valve throttled. No problems expected with dedicated ejector steam supplies.	TBD	TBD	
Hotwell water supply	Reduced load at U17 and U3 could affect availability of hotwell water for CMF & desuperheat systems.	Increased operator attention required at plants to monitor and adjust the systems.	Review P-min at each unit to maintain hotwell water supplies.	Turbine bypass at U17 has addressed this problem

Source: Geysers Power Company, LLC

The project team has identified key operating constraints for steamfield and power plant equipment that limit the Geysers current ability to operate in a more flexible generation operating mode, and they are discussed below:

Combatting Hydrochloric Acid-dewpoint Corrosion

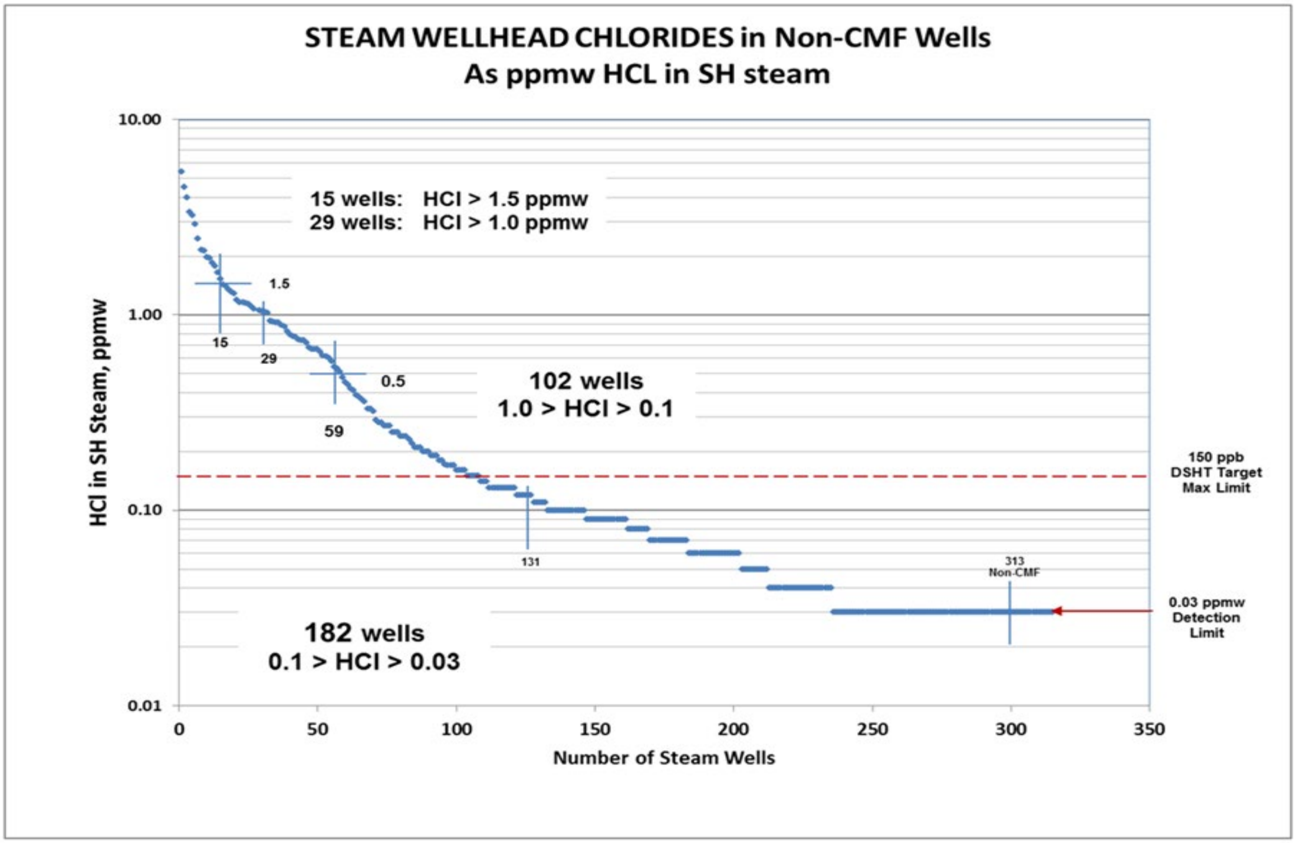
Combatting Hydrochloric acid-dewpoint corrosion in carbon steel pipelines and well casing is an ongoing challenge at the Geysers even with baseload operations, so frequent changes in loads will multiply those challenges. Changing process variables in wellbores and pipelines including steam flowrates, pressures, temperatures, superheat and steam chemistry, shifts the location of potential initial condensation and Hydrochloric acid-dewpoint corrosion attack. The observed impacts of load cutbacks on steamfield facilities will increase as the magnitude and frequency of load cutbacks are increased and as the number of power plants simultaneously cutbacks are increased.

The Hydrochloric concentration in steam wells varies widely across the Geysers steamfields. The distribution of Hydrochloric concentrations in superheated steam is shown in Figure 6.

There are three main categories of wells:

- High volatile chloride wells > 5ppmw that require continuous scrubbing at the wellhead with caustic solution to protect downstream carbon steel piping
- Moderate volatile chloride wells from 0.5 to 5.0 ppmw volatile chloride. High superheat must be maintained in these wells to avoid corrosion attack.
- Low volatile chloride wells < 0.5 ppmw HCl

Figure 6: Volatile Chloride Concentrations in Geysers Steam Wells



Source: Geysers Power Company, LLC

The distribution of high Hydrochloric wells varies between steamfields (designated with the same unit name that the wells feed). Corrosion failures occur often in areas of high Hydrochloric concentrations in steam. Loss of wellbore superheat may lead to condensation and localized corrosion of upper wellbore, wellhead equipment and tie-in piping.

Steam wells with high acid-chloride wells (HCl > 1 ppmw in steam) must maintain maximum possible wellhead superheat to avoid severe wellbore corrosion. Upper wellbore and exposed casing corrosion could occur if inadequate superheat is available to stay above acid-dewpoint; especially in low flow and/or deep wells at full flow. Steam wells were categorized by their volatile chloride concentrations (Hydrochloric as ppmw in superheated steam) into concentration ranges as shown in Figure 7.

Figure 7: HCl Concentration Ranges, Acid-dewpoint and Corrosion Rates

Volatile Chloride Levels versus 1) Acid-dewpoints, 2) corrosion rates and 3) expected service life in carbon steel piping

Volatile Chloride in SH Steam	Volatile HCl as Chloride ppmw in SH Steam	Acid-Dewpoint in degF SH	Estimated CS Corrosion Rate w/o CMF mpy	Estimated Service Life CS Piping yrs	No. of wells in this chloride range	Percent of wells in each category
Very Low	0.03	46	2	118	181	58%
	0.10	39	0	591		
Low	0.11	48	2	89	70	22%
	0.5	51	5	44		
Low Moderate	0.51	54	10	22	42	13%
	1.5	55	12	18		
High Moderate	1.6	58	25	9	12	4%
	5	62	62	4		
High	5.1	66	124	2	2	1%
	15	69	248	1		
Very High	16	72	496	0	6	2%
	100	76	1240	0		
					313	100%

Low chloride wells are flexible for flowrate cutbacks but they are needed for *Dilution* and *Superheat*

~ 20 % 64 Problem wells

~ 5 % CMF Wells Requires continuous NaOH scrubbing. NO THROTTLING!

Source: Geysers Power Company, LLC

Wellbore and Pipeline Corrosion Operating Considerations

High volatile chloride wells (steam with HCl > 0.5 ppmw in superheated steam) have been identified with ongoing annual fieldwide volatile chloride surveys. High volatile chloride occurs across the steam fields. High volatile chloride wells require a case-by-case review to determine the best way to minimize wellbore and pipeline corrosion during flowrate cutbacks which cause reduced superheat and steam condensation.

Corrosion concerns from HCl acid-dewpoint corrosion remains the primary concern that limits deep flowrate cutbacks in portions of the steamfield. There are currently about 85 steam wells with volatile chloride (HCl) levels equal or greater than 0.5 ppmw in steam based on the 2017 fieldwide chemical survey. These high volatile wells are distributed unevenly across the unit area steamfields as shown in Table 2.

Other Wellbore and Pipeline Condensation Effects

At higher levels of flow cutback, for example when steam wells are shut-in and put on bleed, steam condensation can lubricate rocks in open-hole completions and cause sloughing and obstruction of the wellbore. About 13% of steam wells have slotted production liners to protect against wellbore sloughing.

At very low flow conditions, such as startup or potentially running at house load, condensate can build up in pipeline legs. Water knockouts and vent gathering systems are used to collect this condensate. If these systems get plugged, then condensate can build up in a pipeline. As steam velocity increases after the power plant comes back up after curtailment, slugs of liquid water that have condensed in the pipeline can impact a pipeline elbow at high speed, causing a water hammer and potential for pipeline damage.

Non-condensible gases (NCG) can form gas slugs in low velocity sections of pipeline, such as cross-ties, that can overwhelm a power plant's gas removal system, or cause abatement system instability.

Steamfield and Power plant Constraints Effects on P-min Operating Levels

A summary of steamfield constraints and their estimated impacts on recommended P-min values is given in Table 3.

Table 3: Summary of Key Constraints Affecting Geysers Flexible Generation Capabilities (Post CEC Project Status)

Constraints ->											HCl Acid-dewpoint Corrosion	DSHT System Constraints			Hotwell Water Constraints	21 kV Supply Constraints	H25 Abatement System Constraints		Min Load Limiting Constraint
		Notes ->	a	b						c	d	e	f	g	h	i		j	k
owerplant Nam	Unit ID	P-MAX MW	P-MIN MW	CAISO Ramp Rate MW/min	Output Voltage	NCNB PG&E owned Transmission Lin	Voltage Support & Reactive Power?	Super Rotor Installed?	Runback to House Power Capability?	TURBINE BYPASS Status	High Volatile Chloride Wells >0.5 ppmw	Main Pipeline Diameter at Separator	DSHT Minimum Stream Flow MW or kph	DSHT Upgrade Costs	Hotwell Water for DSHT & CMF Scrubbing	21 kV Supply to Geysers Distribution	H2S Abatement System	H2S Abatement Process Limit Min MW	
Sonoma	SO 03	53	15	3	230 kV	Lakeville9	YES	YES	YES	Partial load	15	42" OD	20 MW gross	Prototype Installed	Primary SUPPLY UNIT	SRGRP 2 MW	Stretford	n/a	None with TB
Big Geysers	BG 13	95	22	2	230 kV	Lakeville9	YES	YES			None	48" OD	At P-min	Prototype Installed			Stretford	n/a	DSHT
Socrates	SC 18	72	22	2	230 kV	Lakeville9	YES	YES			6	48" OD	At P-min	$160k		SRGRP 2 MW	Stretford	n/a	21 kV and DSHT
Calistoga	CA 19	92.1	30	4	230 kV	Lakeville9	YES	YES	YES	Partial load	5	42" OD	At P-min				Stretford	n/a	HCl wells and DSHT
Grant	GT 20	62	22	2	230 kV	Lakeville9	YES	YES			15	48" OD	At P-min				Stretford	n/a	HCl wells and DSHT
Lakeview	LV 17	60	22	2	230 kV	Fulton 17	YES	YES		Continuous FULL Load	1	48" OD	At P-min	Turbine Bypass	Primary SUPPLY UNIT		Stretford	n/a	None with TB
Sulfur Springs	SS 14	70	22	2	230 kV	Fulton 12	YES	YES			10	48" OD	At P-min				Stretford	n/a	HCl wells and DSHT
Quicksilver	QK 16	85	25	2	230 kV	Fulton 12	YES	-		Partial OOS	None	48" OD	n/a	n/a			Stretford	n/a	None
Cobb Creek	CC 12	57	22	2	230 kV	Fulton 12	YES	YES			7	48" OD	At P-min		DSHT		~~Burner~~	Switched to Chem Feed	HCl wells and DSHT
McCabe	MC 5/6	85	24	4	115 kV	Eagle Rock	YES	YES		US Continuou FULL Load	4	42"	20 MW gross per unit	US turbine Bypass	DSHT		Burner	600 kph	Burner
Ridgeline	RL 7/8	82	24	4	115 kV	Eagle Rock	YES	YES			7	42" OD	20 MW gross per unit		DSHT		Burner	25 MW	Burner
Eagle Rock	ER 11	74.4	22	2	115 kV	Eagle Rock	YES	YES			3	48" OD	At P-min		DSHT and 9 CMF wells		Burner	35 MW	Burner
Aidlin	AD 01	22	8	4	115 kV	Eagle Rock	YES	-	YES	Continuous FULL Load	All CMF's	20" OD	n/a exclude	n/a exclude			Burner	n/a exclude	n/a exclude
			280	35							73								

Notes:

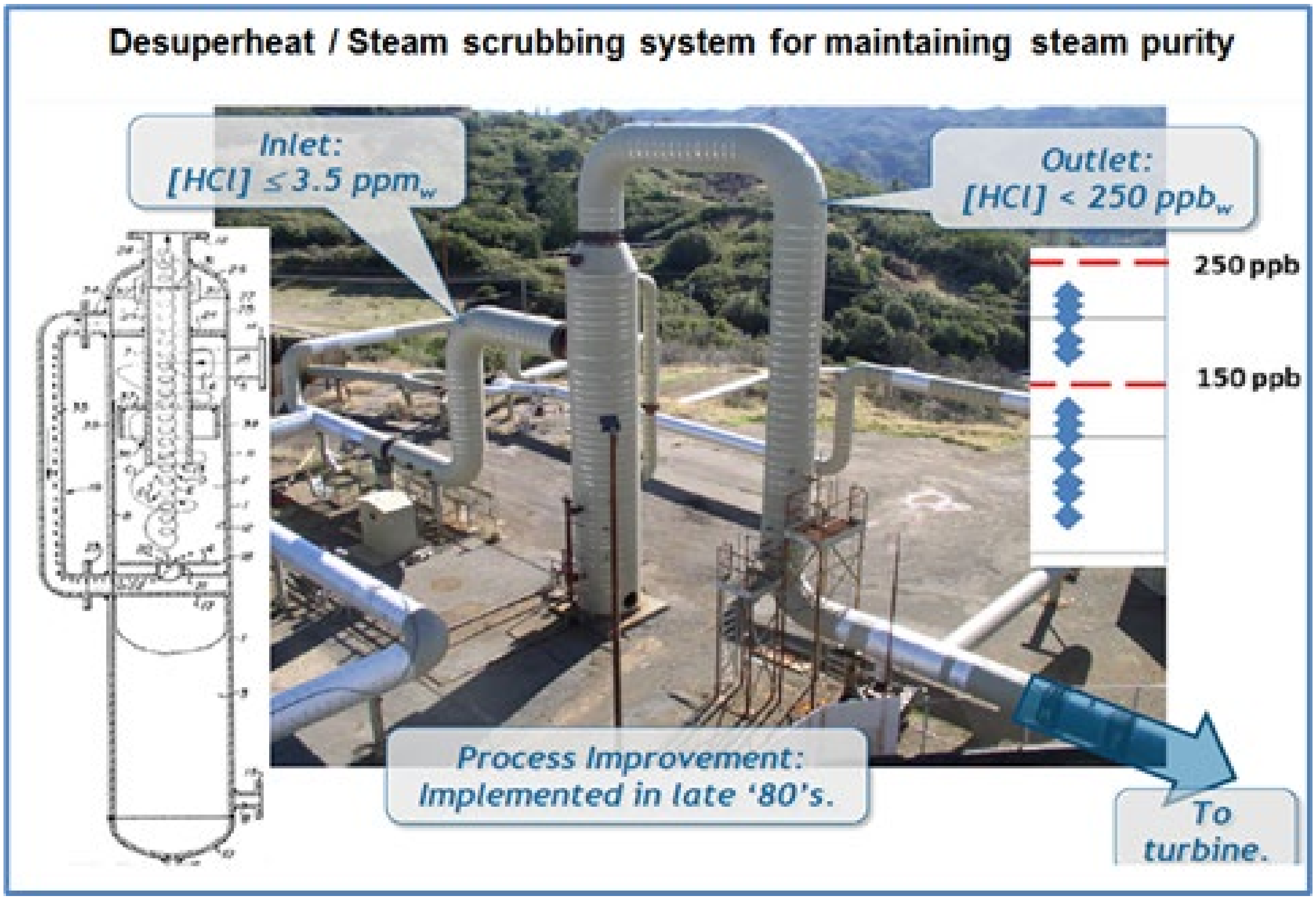
a P-min is the minimum dispatch powerplant load on file with the CA-ISO.
b CAISO maximum ADS ramp rates. Powerplant dispatched individually. Ramp rates are additive and fast for large multi-unit cutbacks. Nominal 2MW/min per turbine-generator.
c New Turbine Bypasses at U5 and U17 can go to Zero MW net continuous. Existing turbine bypasses at U3, U19, and U16 (00S) have limited capacity.
d High volatile chloride steam wells (HCl > 0.5 ppmw) without caustic scrubbing must maintain > 40 deg F superheat-or-be shut in.
e Piping diameters at main separators. Steam velocities drop with flow reduction and increased pressure during load cutbacks.
f Lower limit for DSHT system operation due to low steam velocities.
g DSHT upgrades required to operate down to existing P-min. Includes automated valves and dynamic injection setpoint to track process changes.
h Oxygen-free hotwell condensate for steam scrubbing provided by Lakeview (17) and Sonoma (3). Highlighted units receive this water.
i Socrates (18) and Sonoma (3) provide 21kV internal distribution load for steamfield facilities and SRGRP house power.
j Each powerplant has an H2S abatement system. Emission limits for H2S must be met at all times for the powerplant to operate.
k Limiting load constraint with existing equipment considering steam field and powerplant constraints. Equipment upgrades can lower these limits.

Source: Geysers Power Company, LLC

Desuperheat System Constraints

Desuperheating or steam scrubbing (DSHT) is a process used to clean the steam before it enters the power plants. Oxygen-free steam condensate from shell and tube condenser units, "hotwell water", is injected with atomizing spray nozzles into the piping upstream of a main pipeline separator. The water cools the superheated steam to saturation, i.e. "desuperheats" the steam. Residual water and captured steam impurities including trace hydrochloric acid and particulates are removed from the steam with a large main pipeline centrifugal separator as shown in Figure 8 for Ridgeline (Unit 8).

Figure 8: Main Pipeline Separator

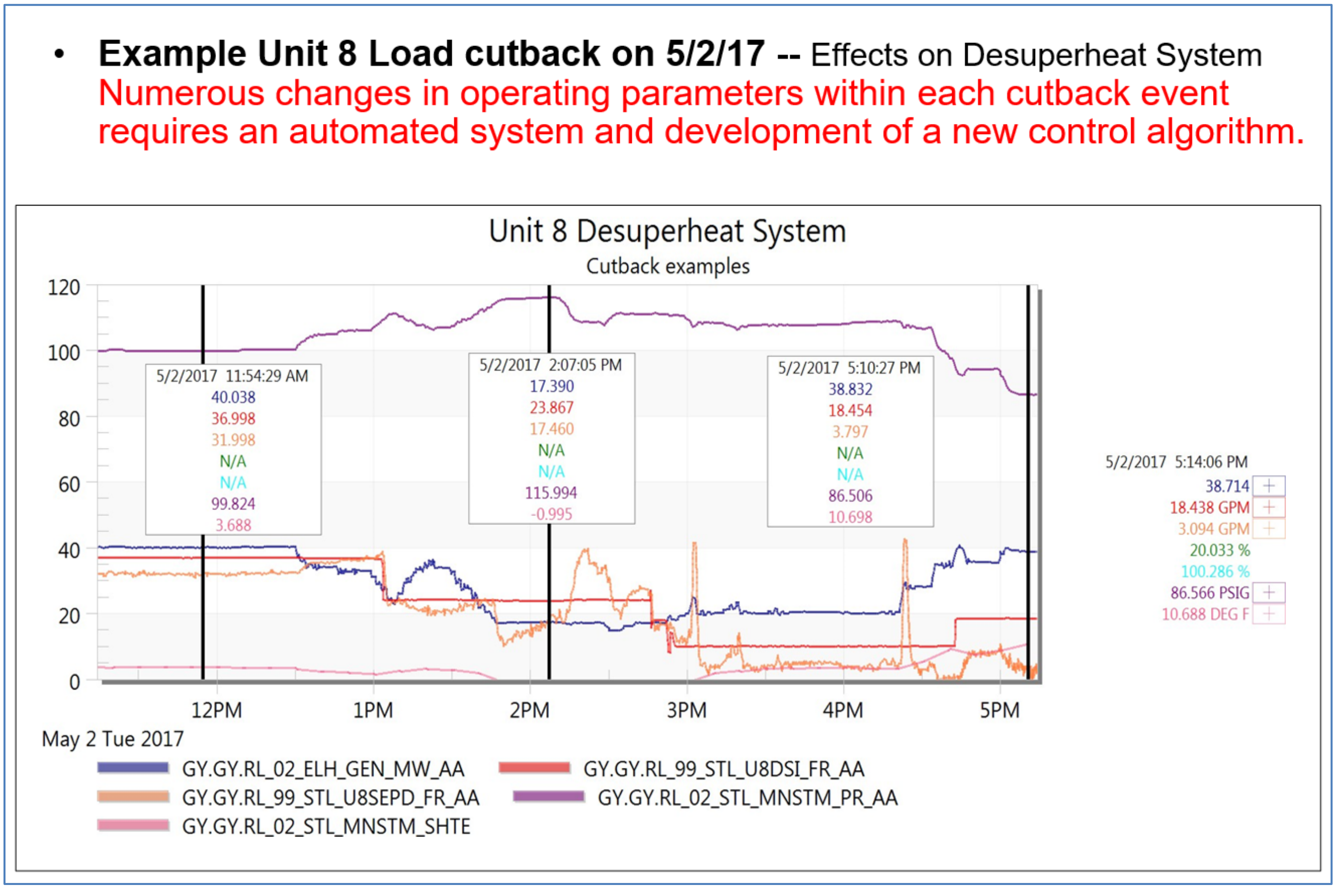


Source: Geysers Power Company, LLC

Continuous DSHT was implemented at most power plants at Geysers power plants in the 1980's and has been instrumental in avoiding turbine deposits, ending turbine stress corrosion cracking, and achieving routine ten year runs between unit overhauls. Continuous DSHT is essential for achieving reliable power plant operation during load cycling operations.

Power plant load changes can cause DSHT system upset conditions and operating problems. DSHT scrubbing systems were designed for full steam flow typical of baseload operation. Cutting back on the power plant load increases line pressure which in turn reduces steam flowrates and changes steam properties and reduces inlet steam enthalpy. These transient process parameters upset the process and can lead to over or under injection of water, water buildup in pipelines at low steam flowrates and loss of nozzle atomization which makes steam scrubbing ineffective in cleaning steam. An example load cycle on Ridgeline (8) shown in Figure 9 shows a long term upset condition.

Figure 9: Effects of Load Cycling on DSHT



Source: Geysers Power Company, LLC

GPC evaluated its desuperheat systems to determine what modifications were needed to adjust the water injection rate automatically as process conditions change and the number of spray nozzles needed and maintain effective steam scrubbing. Existing desuperheat/steam-scrubbing (DSHT) systems were designed for full baseload steam flow and to operate at fixed maximum load point. Automated DSHT valves and automated controls are needed to implement Flexible Generation to achieve reliable DSHT operation.

Shutting off nozzles in sequence is required as water demand drops, to maintain atomization of injected water at reduced flows. The existing Modicon PLC's used for DSHT control valve position remote setpoint cannot handle the control logic needed for valve sequencing and dynamic water injection setpoint equations required for Flex Gen operation.

Existing DSHT systems require frequent operator monitoring of process conditions on the DCS during load changes and injection setpoint changes. Multiple load changes on multiple power plants cannot be effectively monitored and adjusted with manual changes by Central Operations operators. This problem lends itself very well to process automation.

The current DSHT controls consist of a control valve on the injection water with manual remote setpoint on the valve position. Reduced operator coverage requires automated DSHT controls. Multiple load changes on multiple units cannot be handled with manual changes by Central Operations. The existing Modicon PLC (process loop controller) cannot handle the control logic and the valve sequencing algorithms needed for Flex Gen operation. Shutting off nozzles is required to maintain atomization of injected water at reduced flows.

Recent power plant control system upgrades provided an opportunity to improve the DSHT system controls and test a prototype. The upgraded PLC allows more sophisticated logic algorithms to control DSHT injection rate and turn nozzles ON/OFF as needed. Nozzle curves of flowrate versus nozzle upstream pressure were developed for DSHT systems. By turning nozzle ports off sequentially the nozzle delta-P and proper atomization of injected water can be maintained as the injection flowrate is reduced to match hotwell water demand for the variable steam flowrate and steam superheat. An algorithm was developed to calculate a dynamic injection setpoint as process conditions change.

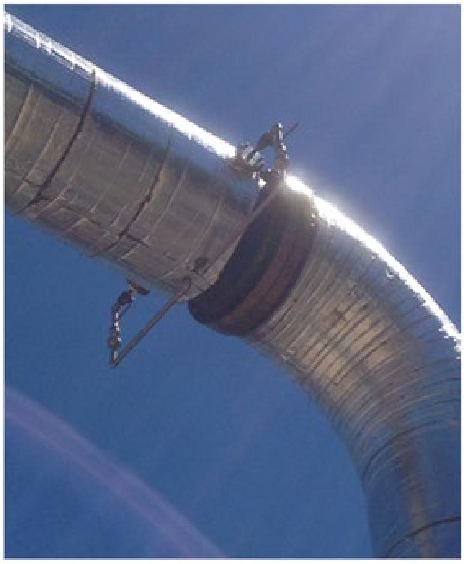
Flex DSHT is a name used for upgraded desuperheat/steam-scrubbing systems with equipment and control upgrades. The objectives for Flex DSHT are the following:

- Automate DSHT injection flow changes vs MW (steam flow), line pressure and superheat
- Implement a heat/mass balance algorithm for dynamic injection rate setpoint changes
- Maintain nozzle DP for atomization of water and proper steam scrubbing (sequencing nozzles ON/OFF as load changes).
- Avoid water buildup in pipelines (avoid potential for water hammer)
- Maintain continuous separator drain flows (to continuously remove steam impurities)

Nozzle ports were added on the upper horizontal pipeline leg into the separator to allow shutoff of lower nozzles and avoid water buildup and potential water hammer risk. Separate feed lines with ON/OFF solenoid valves on each nozzle port were installed to allow choosing which nozzles to use and maintain proper nozzle delta-P and atomization of injected water. These DSHT equipment upgrades are shown in Figure 10 & 11.

Figure 10: Flex DSHT upgrades at Unit 13

DSHT System Equipment Upgrades



Nozzles on upper horizontal leg into separator added to allow shutting off lower nozzles and avoid water buildup and water hammer risks.

Solenoid ON/OFF valves and separate flow lines to each nozzle to maintain high nozzle DP and atomization during DSHT injection rate changes during future Flex Gen operations.

Source: Geysers Power Company, LLC

Figure 11: Flex DSHT Upgrades Summary

Flex DSHT = Desuperheat System Upgrades for Flex Gen

Project Scope Detail

- Add nozzle ports on horizontal line into separator to avoid water buildup and water hammer risk
- Install separate feed lines & solenoid valves on nozzle ports to adjust DHST injection to steam rate
- Upgrade PLC to allow algorithm to control DSHT injection rate and turn nozzles ON/OFF as needed
- Implement "dynamic DSHT injection rate" to follows changing process conditions

Project Justification

- Automated DSHT controls are needed to implement Flexible Generation (aka Load Following)
- Existing DSHT systems designed for baseload and operated at fixed maximum load point
- Existing Modicon PLC can not handle the controls algorithms needed for Flex Gen operation
- Automated nozzle ports is required to maintain atomization of injected water at reduced flows

Additional Factors

- Cyclic load operation may provide economic incentives if risks can be managed
- Multiple load changes on multiple units creates ongoing process upsets that can not be handled with manual changes by Control One. Reduced operator coverage requires automated DSHT controls.

Source: Geysers Power Company, LLC

Steam Velocities Set Lower Operating Limit for DSHT near Existing P-min

Low steam velocities occur at reduced steam flowrates and higher pipeline operating pressures during load cutbacks and set a lower limit on DSHT system operation. At velocities of about 40 feet per second the velocity becomes too low to achieve effective scrubbing of steam. Injected water falls by gravity and separator removal efficiency is also adversely affected.

Steam velocities vary with steam flowrate and line pressure which changes the density of steam. The minimum required velocity of about 40 feet per second occurs at about 350 kph in 42" and 48" steam piping. Figure 12 shows calculated steam velocities for 48" OD steam separator piping used at 110 MW original nameplate power plants. The block arrows show the downward trend of velocities with typical drops in flow and increased line pressures during load cutbacks. This lower operating limit for DSHT is consistent with operating practices that typically do not turn on DSHT until the unit is rolling and has reached about 20 MW load.

Figure 12: Velocities in 48" separator piping at reduced loads

Desuperheat/Steam Scrubbing -- Velocities in 48" OD Separator Piping

Steam Velocities versus Steam Flowrate (load cutbacks) and Line Pressure

Calculated velocities in 48" OD inlet & outlet piping of main pipeline separators: U11, 12, 13, 16, 17, 18, 19, 20

48" OD Acs = 12.05 Ft2   Atmos P = 13.4 PSIA

House Power 5 MW

				Line Pressure							
			PSIG	50	60	70	80	90	100	110	120
			PSIA	63.4	73.4	83.4	93.4	103.4	113.4	123.4	133.4
	MW net	MW gross	Spec Vol Ft3/lb	6.81	5.94	5.26	4.73	4.29	3.93	3.63	3.37
House	-	5.0	100,000	15.7	13.7	12.1	10.9	9.9	9.1	8.4	7.8
	5.0	10.0	200,000	31.4	27.4	24.3	21.8	19.8	18.1	16.7	15.5
	10.0	15.0	300,000	47.1	41.1	36.4	32.7	29.7	27.2	25.1	23.3
	15.0	20.0	400,000	62.8	54.7	48.5	43.6	39.6	36.3	33.5	31.1
P-min	20.0	25.0	500,000	78.5	68.4	60.7	54.5	49.5	45.4	41.9	38.9
	25.0	30.0	600,000	94.3	82.1	72.8	65.4	59.4	54.4	50.2	46.6
	30.0	35.0	700,000	110.0	95.8	84.9	76.3	69.3	63.5	58.6	54.4
	35.0	40.0	800,000	125.7	109.5	97.1	87.2	79.2	72.6	67.0	62.2
	40.0	45.0	900,000	141.4	123.2	109.2	98.1	89.1	81.6	75.3	70.0
	45.0	50.0	1,000,000	157.1	136.9	121.3	109.0	99.0	90.7	83.7	77.7
Full Load	50.0	55.0	1,100,000	172.8	150.5	133.5	118.9	108.9	99.8	92.1	85.5
	55.0	60.0	1,200,000	188.5	164.2	145.6	130.8	118.8	108.9	100.5	93.3
	60.0	65.0	1,300,000	204.2	177.9	157.7	141.7	128.7	117.9	108.8	101.1
	65.0	70.0	1,400,000	219.9	191.6	169.8	152.6	138.6	127.0	117.2	108.8
	70.0	75.0	1,500,000	235.6	205.3	182.0	163.5	148.5	136.1	125.6	116.6
	75.0	80.0	1,600,000	251.3	219.0	194.1	174.4	158.4	145.1	133.9	124.4
	80.0	85.0	1,700,000	267.1	232.7	206.2	185.3	168.3	154.2	142.3	132.1
	85.0	90.0	1,800,000	282.8	246.3	218.4	196.2	178.2	163.3	150.7	139.9
	90.0	95.0	1,900,000	298.5	260.0	230.5	207.1	188.1	172.3	159.1	147.7
	95.0	100.0	2,000,000	314.2	273.7	242.6	218.0	198.0	181.4	167.4	155.5
	100.0	105.0	2,100,000	329.9	287.4	254.8	228.9	207.9	190.5	175.8	163.2
	105.0	110.0	2,200,000	345.6	301.1	266.9	239.8	217.8	199.6	184.2	171.0
Design Point	110.0	115.0	2,300,000	361.3	314.8	279.0	250.7	227.7	208.6	192.5	178.8
	115.0	120.0	2,400,000	377.0	328.4	291.2	261.6	237.6	217.7	200.9	186.6
	120.0	125.0	2,500,000	392.7	342.1	303.3	272.5	247.5	226.8	209.3	194.3

Source: Geysers Power Company, LLC

Power Plant Constraints on Flexible Generation

The anticipated effects of cyclic operations to low power plant loads were evaluated for Geysers power plants operated by GPC. The primary operating limits for power plant operating systems were identified to be: (examples shown in Figure 13)

- Cooling tower water balance

- Exit velocities at last stage turbine blades
- Motive steam pressure steam ejector (condenser vacuum system)
- Manual steam seal adjustments
- Balance of plant systems
- Power plant H2S abatement systems

Cooling Tower Water Balance

Cooling tower water balance becomes more difficult at lower power plant loads and longer duration cutbacks. An evaluation (Ref_) determined the effects of ambient temperatures on cooling tower performance. On very hot days at reduced loads cooling towers can go on "negative water balance", a situation in which insufficient condensate for makeup is created to allow blowdown from the cooling tower and salts build up with cycles of concentration as the same water is repeatedly circulated and evaporated in the towers. Salt buildup can cause increased corrosion of circulating water systems and cooling towers.

In some power plants, tertiary treated municipal wastewater, water from the Santa Rosa Geysers Recharge Project (SRGRP), has been added as cooling tower makeup. This has been done at Sonoma (Unit 3) and Lakeview (Unit 17) to help replace hotwell water lost to scrub water exports from each power plant and at Grant (Unit 20) due to high DSHT hotwell water usage rates at that unit. Cooling tower water balance has not become a problem yet at other power plants with the current frequency and duration of load following type curtailments. Deep load cutbacks to P-min on very hot days would likely create a cooling tower negative water balance problem at all power plants not receiving SRGRP water for cooling tower makeup. Deep load cutbacks should be avoided on very hot days to avoid this constraint. Turbine bypasses can help reduce water balance problems depending on how they are operated.

Exit velocities of Last Stage Turbine Blades

Geysers power plant original design rotors have design limitations on the last stage turbine steam exit velocity that can cause vibration and cyclic fatigue at low steam flowrates. The advanced turbine blade designs of so-called "super rotors" have eliminated this issue. Power plants with super rotors are designed to safely go to house load (0 MWnet). All Geysers power plants except Quicksilver (16), Calistoga (19-U1) and Aidlin have super rotors. The minimum load for Quicksilver(16) is 25 MWnet because of this issue. Rotor upgrades are scheduled for these units that will eliminate this power plant constraint over time.

Steam Deal Manual Adjustments

Steam seals systems flow steam into the turbine bearing seal labyrinth to exclude air leakage into the turbine and avoid turbine bearing corrosion. At some Geysers power plants the steam seals need repeated manual adjustments with each load change of 10 MW or more. Frequent load changes may require better instrumentation, and better controls to maintain proper steam flow to the seals as loads change.

Motive Steam Pressure for Ejector Systems

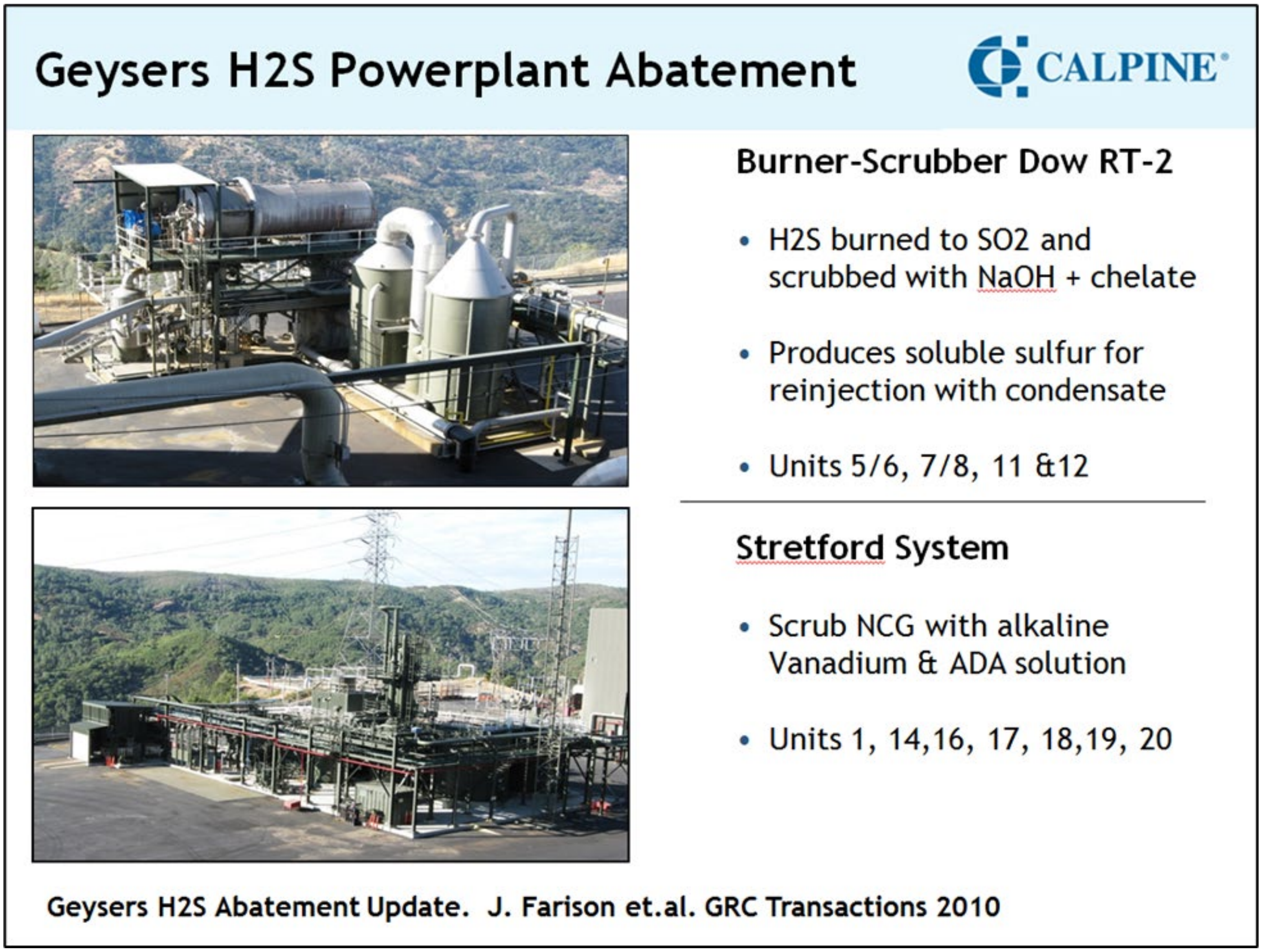
Minimum pressures are required for proper steam ejector performance. Steam flowrate cutbacks can rob steam from the steam ejector vacuum systems, if throttling for steam flowrate suppression is done at wellhead flow control valves, rather than turbine control valves. Ejector performance during load curtailments may require further study and operational troubleshooting. Dedicated steam supply from a separate well which has been implemented at some units eliminates this concern.

Flexible Generation Effects on Power Plant H2S Abatement

Hydrogen sulfide (H2S) gas accompanies the geothermal steam supplied to the power plants at The Geysers. Environmental regulations require that the gas be removed (abated) prior to the release of the steam condensate exhausted from the plants. All of The Geysers plants have been constructed with H2S abatement systems as an integral part of the plant (Farison et.al 2010). The two H2S primary abatement systems are the Stretford system and the Burner-Scrubber system as shown in Figure 13.

Changes to the steam flowrate that results from MW load adjustments (Flexgen) have a negative effect on the operation of the H2S abatement systems, resulting in an increase in the cost to operate them, an increased risk of non-compliance with regulatory permit conditions, and an increased safety risk. Capital investment, automation, and innovation will be needed to mitigate the negative aspects of Flexgen load adjustments. An outline of potential operating problems for H2S abatement systems is given in Table 4.

Figure 13: Geysers Power Plant H2S Abatement Systems



Source: Geysers Power Company, LLC

Table 4: Potential Operational Impacts of Load Cycling – Powerplant H2S Abatement Systems

Environmental Compliance	Expected Effects	Potential Costs	Mitigation Steps	Examples
Particulate Emissions from Power Plant	Reduced condensate production during partial load operation may cause "negative water balance" in cooling towers with high cycles of concentration and a salt build up in the cooling towers which will result in increased particulate emissions out of the stacks.	Air District regulations limit cooling tower particulate emissions. If this limit is exceeded, Notices of Violation (NOVs) and fines could be issued.	Flush salts out of the towers with increased condensate by avoiding low load operation. Cutting out cooling tower fans increases condensate can help alleviate this problem but would result in lower plant efficiency.	
Stretford H2S Abatement System Plugging	Low load operation may result in increased salt build up in the Stretford H2S abatement systems. Crystallization of these salts can cause equipment plugging that requires unit outages to eliminate.	Plant outage time, increased chemical costs	Install piping system to reduce solids.	

Burner H2S Abatement System Burner Flame Stability	1) Low Gas flows means less combustible gas 2) Low gas flows through the burner nozzles could result in the flame traveling backwards up the has supple line (burn back).	1) More process propane will be needed to maintain flame temperature 2) Equipment damage due to burn back could result in burner outages and increased chemical cost. Failure of equipment during burn back could present a safety hazard.	1) Automate the start and stop and modulation of process propane at low burner temperatures. 2) Install a manifold with automated valves for accommodating low gas flow rates.	High propane costs at some powerplants.

Source: Geysers Power Company, LLC

Effects of Load Cycling on Burner-Scrubber H2S abatement systems

Geysers Units 5 through 12 were constructed with direct contact condensers, wherein cooling water is sprayed directly into the steam exiting the turbine. Separation (termed partitioning) of the H2S gas into liquid and gas phases occurs as a result of mixing the steam and cooling water. At these plants, H2S abatement is accomplished by burning the gaseous H2S portion along with combustible hydrogen and methane gasses contained in the non-condensable gas stream. The H2S thus converted to sulfur dioxide (SO2) in the Burner is scrubbed with cooling tower water forming sulfurous acid. The portion of H2S remaining in the liquid phase (condensate), is treated by reacting with a metal chelate (Fe-HEDTA), yielding elemental sulfur. When the sulfurous acid produced in the Burner/Scrubber is mixed with the sulfur produced in the condensate/cooling water, the resultant chemical reaction produces a non-volatile water soluble sulfur salt (thiosulfate, S2O3=) with little or no suspended solids, which is removed from the system through cooling tower blowdown and re-injected into the steam reservoir.

Reducing MW load on a Burner/Scrubber equipped plant causes operational difficulties and increases operating costs. The Burner/Scrubbers installed in the 1980's were designed for base loaded plants with significantly higher gas and H2S flowrates. Lowering the steam flow to the plant reduces the amount of H2S and non-condensable gas, which results in lower fuel heating values (BTU's). Supplemental propane must be added to increase the BTU value in order to maintain combustion.

The reduced gas flowrate also results in lower gas velocity in the burner, such that the "flame front" is no longer in view of the flame scanners that monitor the flame and ensure that the flame does not burn back into the inlet piping. To remedy the flame front position problem, operators can add combustion air and increase the velocity, but this operation is delicate even with an automatic proportional controller, and normally results in flame failure and a Burner trip. Combustion adjustments are nearly impossible when the plant is being operated remotely from central control or an adjacent plant. When the Burner trips, the gaseous H2S is automatically treated through the action of caustic soda added to the condensers, scrubbing the gas into the condensate where, after adding additional metal chelate, the H2S is removed in the Burner backup system. Each step taken to transition to the chemical feed backup system is accompanied by a regulatory compliance check that if not properly completed could result in a violation of the Air Quality Permit to Operate, including fines and additional operational limits. Elemental sulfur produced after the Burner trip is not dissolved by sulfurous acid, and it builds up in the cooling tower water, settling on heat transfer equipment thus reducing plant efficiency. Cooling tower water containing the solid elemental sulfur can cause injection well plugging when it is re-injected back into the steam reservoir.

Upon increasing plant MW load the Burner may be re-lit with added caution. Due to condenser air leakage, the vent gas composition might be in the combustible or explosive mixture concentration range as load is increased, and an ignition source such as a static discharge or mechanical friction can ignite the gas prematurely causing a fire or explosion in the piping upstream of the Burner.

With the exception of Aidlin Power Plant (Unit 1), all of The Geysers plants have intertied steam supplies, such that changing MW load at one plant changes the stream flow and pressure at another plant. There is a large geographical difference in the amount of non-condensable gas and H2S across the steam field. Reducing the steam flow at one plant might shift high H2S steam to another plant, which results in unsteady state (transient) conditions. Operating experience has provided some examples wherein protocols are enacted to adjust for transient conditions. Currently, the practical strategy to maintain regulatory compliance during transient conditions is to add expensive chemicals and "over abate" plants unnecessarily until a proper course of action can be developed.

In summary, Burner/Scrubber H2S abatement systems were not designed for frequent MW load fluctuations. The result of flexible generation on Burner equipped plants is:

- Difficulty controlling combustion, especially during transient conditions and when operating remotely
- Frequent Burner trips
- Added cost for propane, caustic soda, and metal chelate.
- Load changes and transient gas compositions increase operational safety risks
- Injection well plugging
- Increased regulatory Notice of Violation risks
- Over-abating and ratcheting down of H2S emission limits requiring purchase of additional H2S chemicals

Effects of load cycling on Stretford H2S abatement systems

Power plants constructed with surface condensers (shell and tube) do not mix the condensing steam directly with cooling water, so the H2S in steam exhausted into the condenser is mostly partitioned to the gas phase. At these plants (Sonoma (Unit 3), Big Geysers (Unit 13), Sulphur Springs (Unit 14), Quicksilver (Unit 16), Lakeview (Unit 17), Socrates (Unit 18), and Grant (Unit 20), the gaseous H2S is treated in a "Stretford" H2S abatement system that utilizes a vanadium based alkaline salt solution in a liquid oxidation reduction reaction to convert the H2S into elemental sulfur. The sulfur is subsequently removed from the solution to create a sulfur cake and is marketed as an agricultural soil amendment.

Stretford equipped plants are more flexible than Burner-scrubber equipped plants in terms of handling changes in the supplied H2S mass flows that result from MW load changes. Two reasons for this flexibility are: 1. The Stretford equipped plants are oversized due to the reduced steam flow from the reservoir pressure decline, and 2. They are geographically located (with the exception of Unit 17) in low H2S areas where the injection of wastewater has greatly reduced the H2S concentration in the supplied steam.

Operational difficulties arise in Stretford equipped plants during low load operation because of by-product formation that occurs due to increased side reactions between the H2S and oxygen, which is present in much higher concentrations in the vent gas during low load operation. Over time, the side reactions create an overabundance of sulfur-based salt that interferes with the oxidation reduction reactions, and the salt has to be physically removed from the system in order to maintain compliance with the regulatory concentration limit in the treated vent gas stream. Removal of the salt is expensive and generates a hazardous waste that requires trucking and disposal at a hazardous waste landfill. Salt production occurs over a very long time period and does not generally present itself as a sudden change when MW load changes so operational difficulties due to flexible generation are generally lower at Stretford units than Burner/scrubber units.

The regulatory operating limit applied to Stretford plants is very tight, allowing only 10 ppm H2S in treated gas emissions. Chemical consumption at low H2S plants is usually optimized so while the Stretford might be operating at 10% of the designed capacity, the chemical strength might have been reduced to avoid wasting money. When a steam shift from a high H2S area occurs during flexible generation, the 10-ppm limit can be easily exceeded, until an operator can arrive on site to make system adjustments. This is particularly true at Unit 17, where high H2S steam from Unit 11 can produce treated gas H2S concentrations in excess of 135 ppm.

Most Stretford equipped plants do not require abatement chemicals to treat the H2S dissolved the steam condensate entering the cooling tower. The partitioning of H2S into the gas phase generally leaves only 10% to 20% of the incoming H2S in the condensate pumped to the cooling tower. This amount is often less than the overall mass emission limit, and therefore does not need to be abated. Steam shifting for flexible generation can result in higher H2S flows sent to intertied plants that results in an unexpected increase in the condensate H2S, raising the H2S emissions to exceed the regulatory limit.

The H2S emission source tests (NSCAPCD Method 102) are required to be done monthly and can only be accomplished manually with a probe inserted into the cooling tower stacks. If steam shifting for flexible generation occurs during a source test, there is an increased risk that the emissions determined will exceed the allowed rate, which will result in a Notice of Violation and possible fines. In order to avoid that possibility, additional H2S abatement chemicals will have to be added any time flexible generation is applied due to the uncertainty of the impact of the steam shifting.

Stretford equipped plants are required by permit to have their monthly source test conducted at full available MW load. If Flexgen is called during a scheduled source test, the test will be voided and have to be repeated to avoid violation of the permit condition.

In summary for Stretford equipped plants, the impact on H2S abatement is:

- Operational difficulties caused by increased production of by-product salt
- Added expense for disposal of by-product salt and makeup chemicals
- Increased risk of regulatory Notice of Violation due to unanticipated steam chemistry changes in inlet steam
- Increased risk of regulatory Notice of Violation due to steam chemistry changes during monthly required power plant emissions source testing.
- Repeat source testing needed due to cancellation of scheduled testing interfering with flexible generation.

- Inability to test Stretford equipped plants at full available load as required.

Both Stretford and Burner equipped plants will require more H2S abatement chemicals (including propane) in order to maintain compliance with regulatory emission limits while under Flexgen operation. The abatement chemicals are not only expensive but, in some cases, (e.g. caustic and vanadium) are hazardous and require tanker transport to The Geysers. Both Air Quality and Water Quality Control Boards discourage adding to the amount of hazardous material hauling as it adds to greenhouse gas emissions and increases the risk of a hazardous materials spill into water resources.

Effects of Turbine Bypasses on H2S Abatement Systems

Turbine bypass has been proposed as a means to avoid shutting in the steamwells during Flexgen, while banking steam for later use. There is an impact on H2S abatement when operating on the Turbine Bypass system. When on Bypass the steam is directed to enter the condenser without passing through the turbine. Since the turbine is bypassed the steam enters the condenser without having exhausted energy against the turbine blades. The result is that the condenser is hotter, and the partitioning of H2S to the gas phase is increased.

Normally an increase in the partitioning of the H2S into the gas phase at a Burner equipped plant would be considered advantageous by reducing the amount of H2S treated in the condensate. For Burner equipped plants the increase in H2S is easily handled by the Burner/Scrubber, however the increase in vent gas temperature also increases the amount of water (humidity) carried by the gas to the Burner. High water carryover due to high vent gas temperature results in cooler Burner flame temperatures, sulfuric acid condensation, metal corrosion, refractory damage, and increased propane needs. High vent gas humidity is also associated with vent gas pipe plugging due to sulfur formation from natural oxidation in the vent gas line when H2S is combined with water and oxygen.

At Stretford equipped plants, the increase in H2S in the feed gas results in an increase of 2 to 3 ppm H2S in power plant treated gas emissions. Due to the very low concentration limit for the gas exiting the Stretford (10 ppm), an increase of only 2 to 3 ppm can cause an exceed of the concentration limit, leading to a possible regulatory Notice of Violation.

In summary, Turbine By-pass operation has the following negative effects on H2S abatement operation:

- Sulfuric acid dewpoint corrosion in the burner
- Burner refractory damage
- Cooler flame temperature requiring adjunct propane
- Sulfur plugging of Vent Gas piping
- Increased risk of a regulatory Notice of Violation

Strategies for Implementing Flexible Generation

Utilize and Maintain Existing Flexible Generation Capabilities

The primary strategy is to understand existing capabilities and limitations from the CEC study and upgrade facilities as needed to achieve reliable operations for ongoing load following type cyclic operations within existing P-max to P-min operating limits.

The Geysers steamfield and power plant facilities already have significant flexible generation capabilities as discussed earlier and that capability must be maintained as grid variability increases over time. Economic dispatch cutbacks or congestion related cutbacks down to P-min periodically occur on individual Geysers power plants with some manageable impacts such as DSHT system transients. However, increased frequency of load following operations that occur simultaneously on multiple plants will require automation to avoid inefficient scrubbing operation and the potential for damage.

One example of this strategy is the installation of turbine bypass at Lakeview (Unit 17) which will improve the reliability of hotwell water supply for DSHT and CMF scrubbing systems across the Geysers steamfields. Another example of this approach is proposed Flex DSHT upgrades to improve the ability to handle cyclic operation without frequent operator intervention.

Existing P-min values total 280 MW which is a 60% reduction from nominal 700 MW baseload levels. Turbine bypass additions at McCabe (Unit 5) and Lakeview (Unit 17) allow reductions in P-min on those units down to near zero net MW. This drops the potential P-min total to 246 MW for an overall cutback of 65 percent if cutbacks can be achieved to those levels reliably without facility damage.

How to perform steamfield cutbacks to avoid corrosion damage?

Without a turbine bypass to maintain continuity of maximum steam flow, low wellhead and pipeline pressures to preserve maximum superheat, the potential for severe damage to steam wells and pipelines from HCl acid-dewpoint corrosion requires some difficult decisions.

High volatile chloride wells with low superheat at the steam well's meter run must be operated with as low of a wellhead pressure as possible to maintain maximum possible superheat. Raising the wellhead pressure for any duration will create localized corrosive conditions at the wellhead and upper wellbore in high volatile HCl content wells.

High volatile chloride steam wells with high superheat can be partially cutback while keeping a minimum target superheat of at least 40 degrees F. Superheat versus flowrate deliverability curves can be used to set minimum flowrate targets for each steam well and flow control can be implemented with the steam well throttle valve and actuator to stay at or above the minimum target superheat to avoid wellhead and upper wellbore corrosion in high HCl steam wells.

Low chloride steam wells mix with the higher chloride steam and provide dilution. Reduced pipeline flowrates will reduce pipeline superheat and lead to condensation. Mixing of higher volatile chloride wells with wet steam or allowing the mix of steam to reach close to saturation will increase the corrosion rate in steam pipelines and should be avoided.

These decisions can become automated with automated steam well cutback lists and minimum flow targets based on chloride levels and other criteria and maximum volatile chloride estimates of the combined weighted average steam flows.

Strategies for DSHT system operation

Ideally the DSHT systems can be maintained in operation continuously above their design steam flowrate cutoff points of about 300 kph below which the steam velocities become too low to effectively scrub steam. If the DSHT system must be shutoff due to low steam flowrates, DSHT equipment or system problems, or due to loss of hotwell scrubbing water then all high chloride wells must be immediately shut-in as per normal operating practices today.

Flex DHST automation equipment upgrades and automated dynamic injection rate setpoint as described in Chapter 3, need to be implemented to achieve existing P-min values. Proposed Flex DSHT system upgrades are proposed for phased implementation over the next few years.

How to utilize geothermal turbine bypasses?

How to best utilize turbine bypasses remains an unresolved issue. Initial testing of turbine bypasses at McCabe (Unit 5) and Lakeview (Unit 17) demonstrate that they can successfully avoid identified steamfield and power plant constraints. The major operational benefit of turbine bypass is it allows rapid load cutbacks to target levels and it allows time to make needed steamfield adjustments. However, load following type cyclic operation that involves frequent 5-minute dispatch ramp down and immediate or frequent ramp back up does not allow for steamfield flowrate suppression.

Overall turbine bypass strategy is to avoid steamfield pipeline and wellbore casing damage from HCl acid-dewpoint corrosion and avoid shutting off continuous DSHT steam scrubbing. Cutting back the steam resource during load curtailments and "banking steam" for generation later on was initially expected to provide payback for capital investments needed for expanded flexible operations. However, fieldwide implementation of turbine bypass with sustained maximum steamflow at every power plant does not provide this benefit unless accompanied by some significant level of steamfield flow suppression.

Extended duration of full flow turbine bypassing of geothermal steam is counterintuitive to maximizing geothermal MWh generation to contribute to overall California RPS goals. It simply trades one form of renewable generation for another. Maximum implementation of full load continuous service turbine bypasses at every power plant would be prohibitively expensive. However, there is a benefit in using a turbine bypass which will reduce the impact of increased cyclic operations on steamfield and power plant systems. Going forward, information gained from this study along with turbine bypass operating experience will help optimize the use of turbine bypasses installed as part of this study.

What strategy should be used for power plant ramp rates?

Current Geysers power plant ramp rates of Geysers power plants are adequate for load following operations, and very rapid aggregate ramp rates are achieved during multi-unit cutbacks. Therefore, no changes in power plant ramp rates are anticipated at this time.

Periodic stepwise load changes with incremental load increases (INCs) and decremental load changes (DECs) occur routinely now with real time CAISO ADS 5-minute dispatch. Ramp rates for Geysers power plants are used routinely for load following by CAISO and multi-power plant ramp rates are already fast enough to qualify for real-time Flexible Ramp ancillary services.

Increasing the ramp rate is mechanically feasible from full available load down to P-min in as little as one minute from the time executed as far as power plant equipment capability is concerned. However, impacts on equipment from increased ramp rates are anticipated to increase wear and tear and will be difficult to monitor or assess. Detailed ramp rate related equipment technical details were outside of the scope of this study. Some valve actuator and control system changes may be needed and will require further engineering study.

Maximizing flexible ramp rates on geothermal power plants, for example with Automatic Generation Control (AGC), has the effect of transferring the full variability of wind and solar over to geothermal steamfield and power plants. It also takes away advance notice of the power plant MW load change and removes any decision-making time from Geysers Central Operations needed to adjust and optimize steamfield facilities such as steam shifts and shutting in wells.

Geysers Flexible Generation

- Based upon the results of this study, optimized flexible generation with existing facilities will include the following:
- Partial steam flowrate suppression down to identified steam well and pipeline corrosion limits and avoiding cutbacks on "no touch wells"
- Additional turbine bypass on some units subject to economic justification and cost/benefit evaluations.
- Maintain minimum steam flows for continuous DSHT operation.
- Modifications to Burner-scrubber control systems and/or alternate technologies to achieve H2S emission limits with reduced non-condensable gas flowrates.
- Install Flex DSHT automation upgrades to achieve reliable steam scrubbing down to existing P-min values.
- Identify power plants supplied by steamfields with very few or no high chloride wells that can be cut back to house power plus minimum additional steam flow and net load required to meet minimum steam flow required for DSHT system operation. This includes Big Geysers (Unit 13) and Quicksilver (Unit 16).

Application of Modeling Capabilities to optimize scenarios

The control of a geothermal steamfield is a complex optimization process. Adjusting settings at wells, pipeline sections, and power plants affects the entire system in a manner that is difficult to predict due to the connectedness of all system components – including the reservoir. The integrated model developed in this project provides the tools necessary to optimize control parameters for future potential curtailment scenarios

When optimizing the performance of the system in response to short-term fluctuations in energy demand, operators need to rely on their experience. Support from a simulation-optimization framework will allow them to make decisions based on predicted impacts on net power production without violating constraints ensuring the safe and efficient operation of the steamfield.

CHAPTER 3:
Project Results

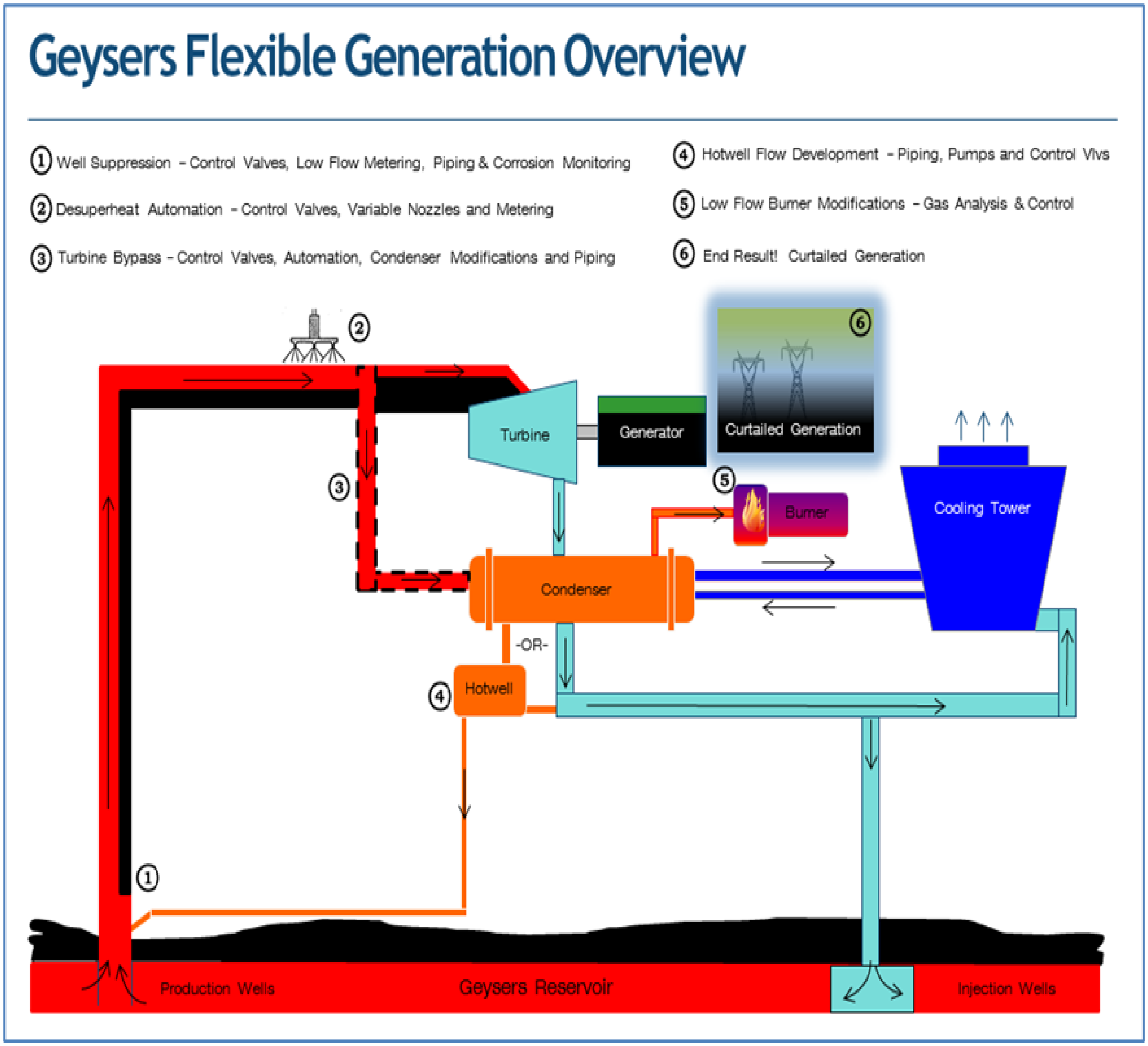
Field and Prototype Testing

Field and prototype testing was instrumental in model validation and calibration. Field testing was also used to refine the assumptions for field constraints and control parameters to formulate a well-posed optimization problem. Field wide model runs indicate that curtailment of about 65% of GPC Geysers current baseload levels down to production levels close to existing CAISO dispatch minimum MW can be achieved temporarily without violating well and steam field constraints.

Based upon the identified steamfield and power plant constraints the following items were identified for Field Testing as depicted in Figure 14.

- Individual well testing for downhole conditions under curtailment
- Sonoma steamfield vortex meters and ROTORK valve actuators
- Desuperheat/steam scrubbing system automation
- Corrosion monitoring sensors at Sonoma
- Hotwell supply reliability from Sonoma
- Sonoma turbine bypass
- McCabe (Unit 5) and Lakeview (Unit 17) turbine bypasses
- Steam crossover pipeline valve automation
- Burner H2S abatement system modifications

Figure 14: Overview of Flex Gen Upgrades



Source: Geysers Power Company, LLC

An overview of the equipment testing for each component is given below.

- Individual well testing for downhole conditions under curtailment

A series of single well testing and multiple well testing were performed to observe steam flow, pressure, heat loss, and temperature effects during flowrate cutback. Steam flowrate, wellhead temperature/pressure and valve position were monitored during a series of stepped flowrate cutbacks. The tests helped to determine steam superheat versus flowrate and how low the flow can be reduced while staying above the HCl acid dewpoint to avoid wellbore corrosion. Results from these were also used to test the accuracy of the HEATLOSS program and understand the dynamic behavior of wells subjected to flowrate changes.

During these tests downhole conditions were monitored with downhole pressure and temperature wireline tools. These surveys provided additional data sets that can be used to study wellbore heat losses under curtailment scenarios and validate the approach to quantify the effects at the wellhead. Results from these downhole surveys have been shared with LBNL scientists for the study on development of coupled model process for the NW Geysers (LBNL CEC sponsored project under a separate GRANT)

Individual well tests at Sonoma with valve actuators & vortex meters

This phase of well testing built upon the earlier individual well testing described above. Some initial testing was done to verify equipment functionality. We will be able to monitor ongoing field performance with the new equipment.

Desuperheat/Steam-scrubbing (DSHT) system automation

The desuperheat/steam scrubbing (DSHT) process injects oxygen-free hotwell steam condensate (steam condensate from shell and tube condenser units) into the main pipelines to wash out steam impurities including chlorides, rock dust and corrosion debris particulates.

The DSHT water injection rate must be cutback during steam flowrate cutbacks to avoid water buildup in steam pipelines and avoid potential water hammer. Automated ON/OFF valves are being installed to allow shutting off nozzles when needed and to maintain nozzle spray atomization. Two prototypes automated DSHT systems were installed at Big Geysers (13) and Sonoma (3) as part of this project.

Corrosion monitoring sensors at Sonoma

Real-time remote wall thickness sensors were installed at Sonoma on the main pipeline near the separator and will be used to monitor and evaluate the effects of flexible generation on wall losses and corrosion rates in the main steam pipeline at Sonoma. Cutting back on steamfield flowrates will change the mix of steam and steam chemistry in the pipeline and change the concentration of volatile chloride or HCl.

DSHT Hotwell supply reliability

A booster pump was added to the hotwell water supply distribution piping near Ridgeline (7) to ensure proper flowrates and gravity system pressures were adequate for corrosion mitigation wells along Ottoboni Ridge.

Unit 5 and Unit 17 turbine bypasses

The Unit 5 and Unit 17 turbine bypasses were installed as part of the CEC project.

The Unit 5 and Unit 17 turbine bypasses were each tested with a simulated load cutback both without steamfield flowrate suppression. The turbine bypass system capabilities were defined with respect to the rate of load shedding and the resulting heat and mass balance of the power plant and cooling tower. The rate of hotwell water production and effects on H_2S abatement systems were also observed and evaluated.

Steam crossover pipeline valve automation

Crossover pipeline valve actuators were installed and tested to confirm their functionality. The operation of remote actuated crossover valves will permit more rapid steam shifting.

Burner/Scrubber H2S Abatement modifications

The Burner/Scrubber power plant H2S abatement system at Cobb Creek (Unit 12) was modified to improve gas scrubbing in the after condenser and go on chemicals to eliminate the burner/scrubber problems at low gas flowrates.

Key results for Geysers Flexible Generation Field Testing

Individual well testing for downhole conditions under curtailment

- GDCF15A-28 manual 50% flowrate cutback tests
    - Wireline downhole T&P monitoring during cutback
    - Steam superheat versus flowrate observed
- Additional one-day cutbacks conducted on a group of wells
- Algorithm developed to estimate superheat versus flowrate and HCl acid-dewpoint during flowrate cutbacks. Algorithm was verified with well test data.
- Geysers annual full-field chemical surveys conducted for 2016, 2017 & 2018.

Individual well tests on wells with valve actuators & vortex meters

- Vortex meters and ROTORK actuators installed on ten Sonoma steam wells.

Desuperheat/scrubbing (DSHT) hotwell injection rate automation

- Automated Flex DSHT systems installed at Big Geysers (13) and Sonoma (3)
- Algorithm created for variable DSHT injection rates as a function of steam flowrate and line pressure and upstream steam superheat.
- Automated DSHT valve sequencing to main nozzle atomization

Corrosion monitoring sensors at Sonoma

- Nine Permasense real-time ultrasonic sensors installed

Hotwell supply reliability from Sonoma

- Cooling tower makeup water piping modifications implemented
- Inline dissolved oxygen (DO) instruments tested at Sonoma

Sonoma turbine bypass

- Sonoma (3) turbine bypass manifold inspected within condenser
- Erosion damage found. Erosion protection “blast shields” installed

Unit 5 and Unit 17 turbine bypasses

- McCabe (5) turbine bypass installed and successfully commissioned.
- Lakeview (17) turbine bypass installed and successfully commissioned.

Steam crossover pipeline valve automation

- Remote activated crossover valve actuators installed at ten locations.
- Crossover pipeline actuators function tested.

Burner H2S abatement system monitoring/modifications

- Unit 5 burner H2S abatement system observed during U5 turbine bypass commissioning/function testing. No problems observed during short test.
- Unit 12 burner system modified with automated chemical system.

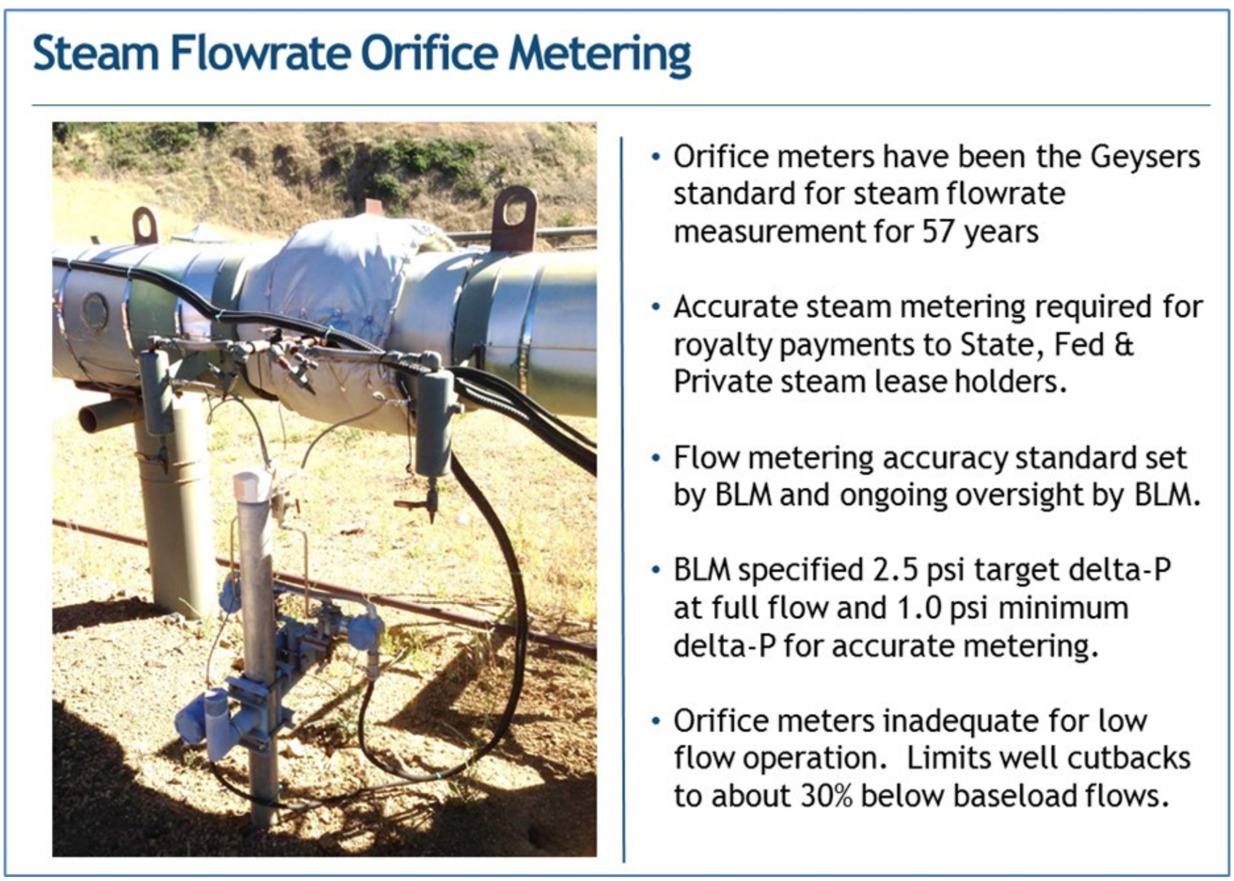
Discussion of Equipment Installed for Flex Gen Field Testing

Steam Flowrate Metering for Flexible Generation

Flexible generation requires that steam well flowrates can be cutback to very low flowrates which can fall below the allowable operating range of an orifice meter. Orifice meters have been the standard method for steam flowrate measurement for over 50 years at The Geysers. Royalty payments to state, federal and private steam mineral right leaseholders are allocated to each leaseholder based upon steam flowrates so accurate and reliable steam flowrate measurements are critical.

The steam flowrate metering accuracy standard is overseen by the Federal Government Mineral Management Service (aka Bureau of Land Management or BLM). Typical steam orifice metering setup at The Geysers is shown in Figure 15.

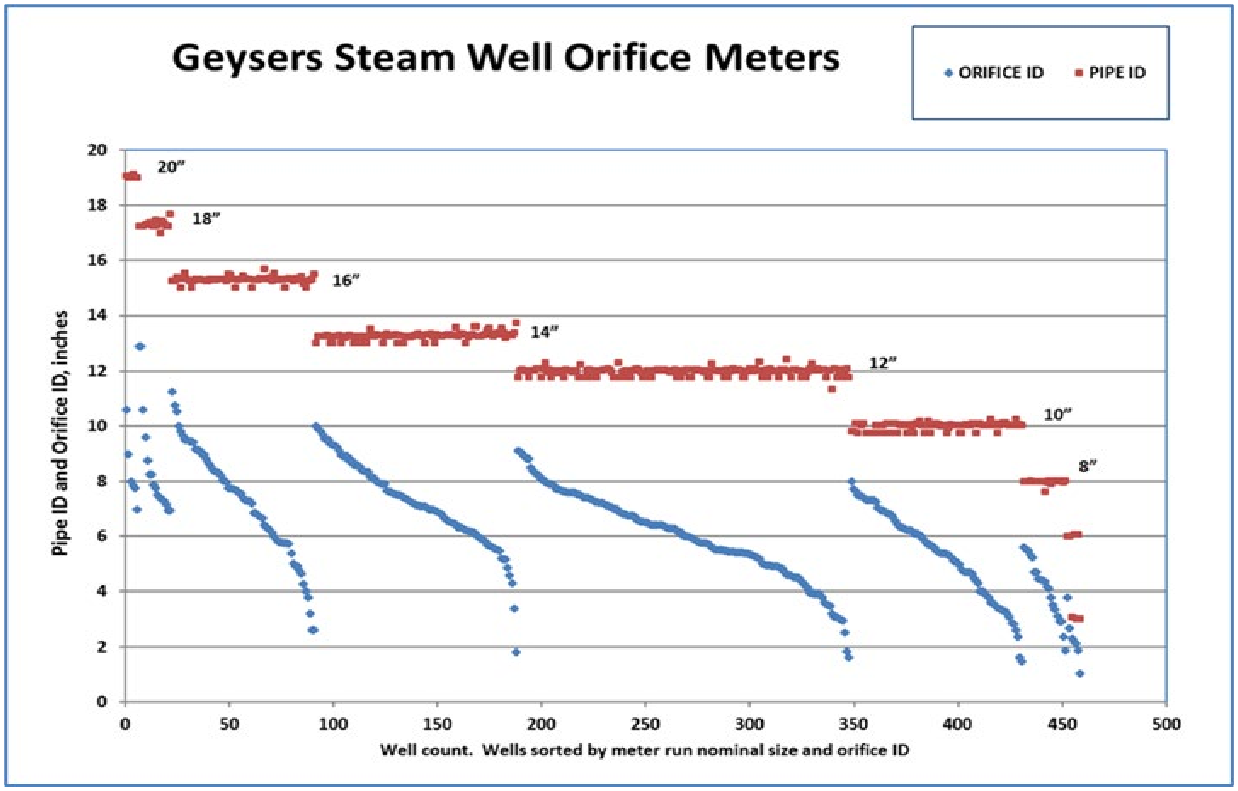
Figure 15: Example setup for steam orifice metering at The Geysers



Source: Geysers Power Company, LLC

The range of orifice meter dimensions, pipe ID and orifice ID, are shown in Figure 16 for all Geysers steam wells.

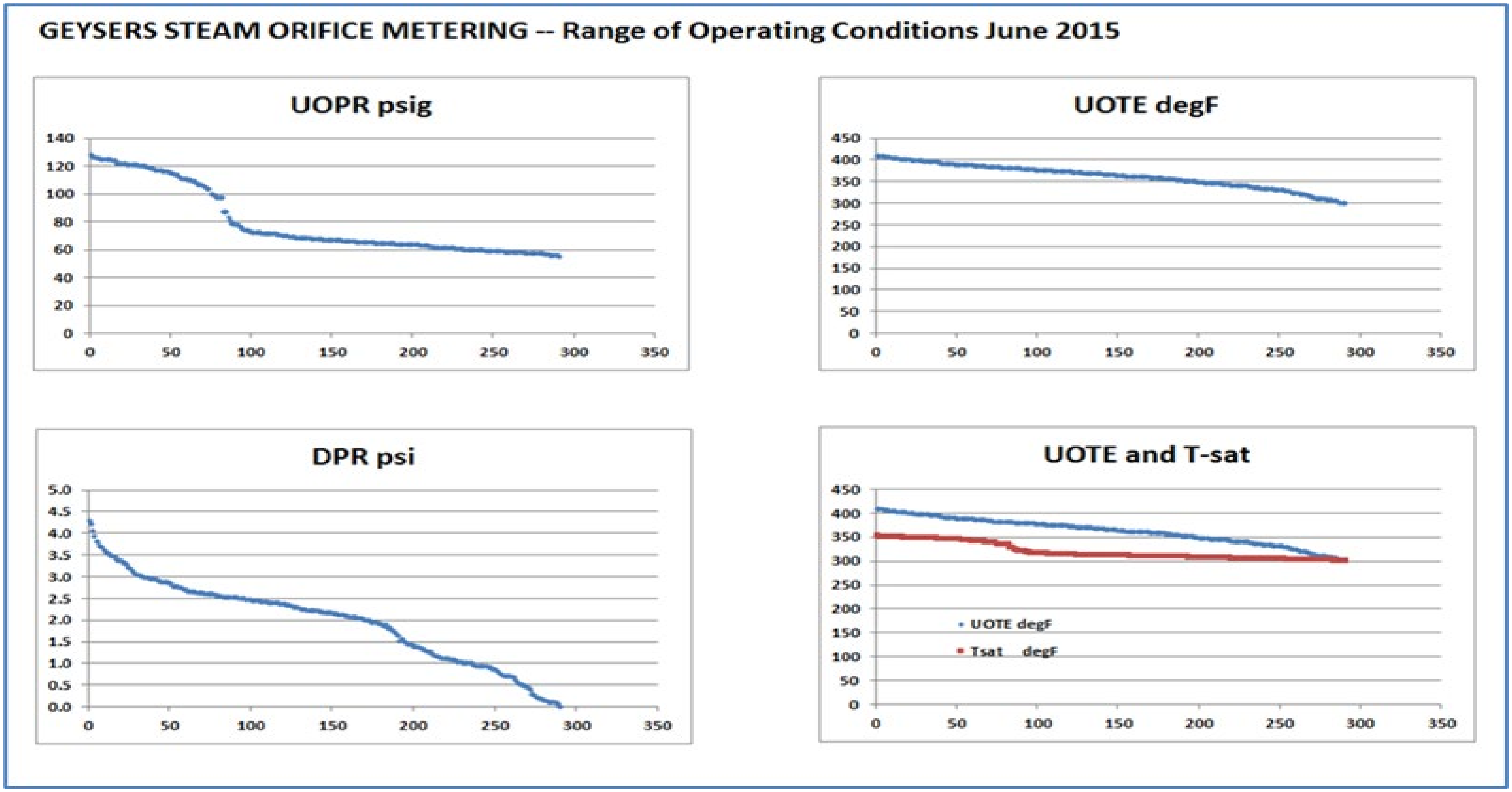
Figure 16: Geysers Steam Well Orifice Meter Dimensions



Source: Geysers Power Company, LLC

The range of orifice measurement parameters, temperature deg F, upstream pressure psig and delta-P psi are shown in Figure 17.

Figure 17: Geysers Orifice Metering Dimensions and Parameters

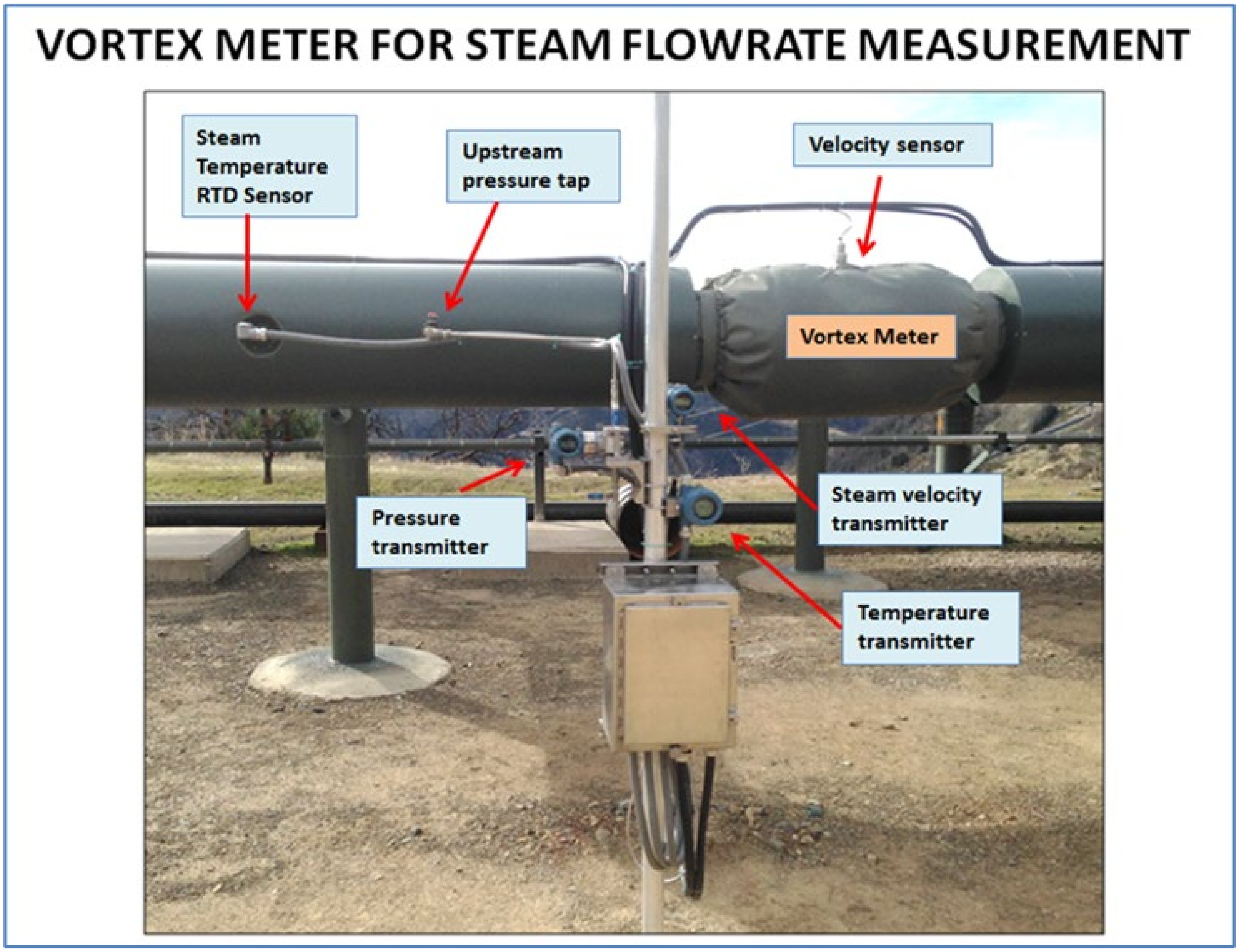


Source: Geysers Power Company, LLC

Vortex meter testing

Vortex meters were investigated and tested as a viable alternative to orifice metering for flexible generation. Vortex meters were installed on 10 steam wells in the Sonoma steamfield as part of CEC project. The typical vortex meter setup is shown in Figure 18.

Figure 18: Example Vortex Meter in Sonoma Steamfield



Source: Geysers Power Company, LLC

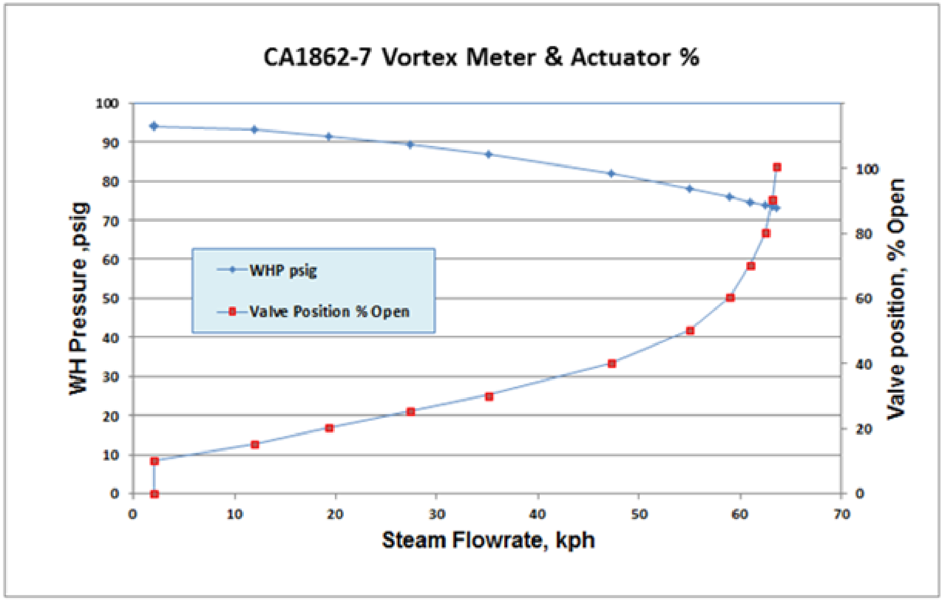
Figure 19: Commissioning of Vortex Meter and Actuators at Sonoma

Steam Well CA1862-7 – Vortex meter and Actuator Functionality Test

CA1862-7

5/29/2018

Flowrate kph	WHP psig	Valve Position % Open	Stm Vel ft/sec
63.6	73.2	100.3	84
63.1	73.4	90.3	83
62.5	73.9	80.3	82
61.0	74.7	70.3	80
59.0	76.0	60.3	78
55.0	78.2	50.3	72
47.2	81.9	40.2	62
35.1	86.9	30.2	46
27.3	89.3	25.2	36
19.4	91.6	20.2	26
12.0	93.3	15.1	16
2.0	94.0	10.1	3
2.0	94.4	0.0	3



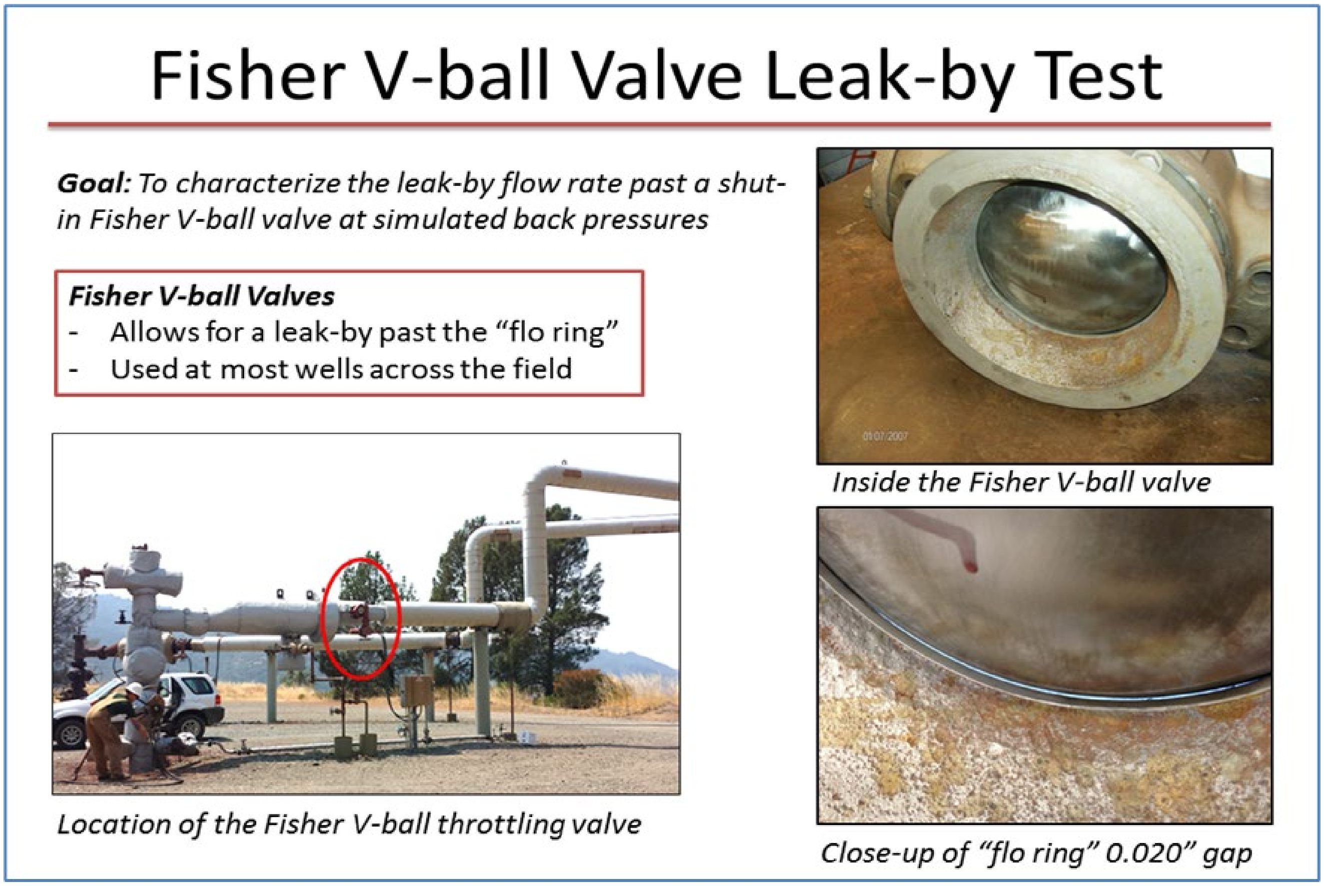
Source: Geysers Power Company, LLC

Steam Well Throttle Valves

Steam well throttling valves and actuators were installed in the late 70's and 80's on most Geysers steam wells for H2S abatement reasons to quickly cutback vented steam and avoid H2S emissions during power plant outages. In addition to avoiding steam emissions, throttling steam remains an important tool for Central Operations to control individual steam well flowrates and manage problems such as pipeline gas loading, chloride levels and avoid static dead legs. Functional throttling valves and actuators are needed on all steam wells to optimize steamfield operations.

Throttle valves are installed in the wellhead tie-in piping on most Geysers steam wells. Most steam wells also have motorized actuators that can be remotely operated by changing the valve position setpoint. Most steam wells typically use the Fisher V-ball valve as shown in Figure 20.

Figure 20: Fisher V-ball Throttle Valve on Geysers Steam Wells



Source: Geysers Power Company, LLC

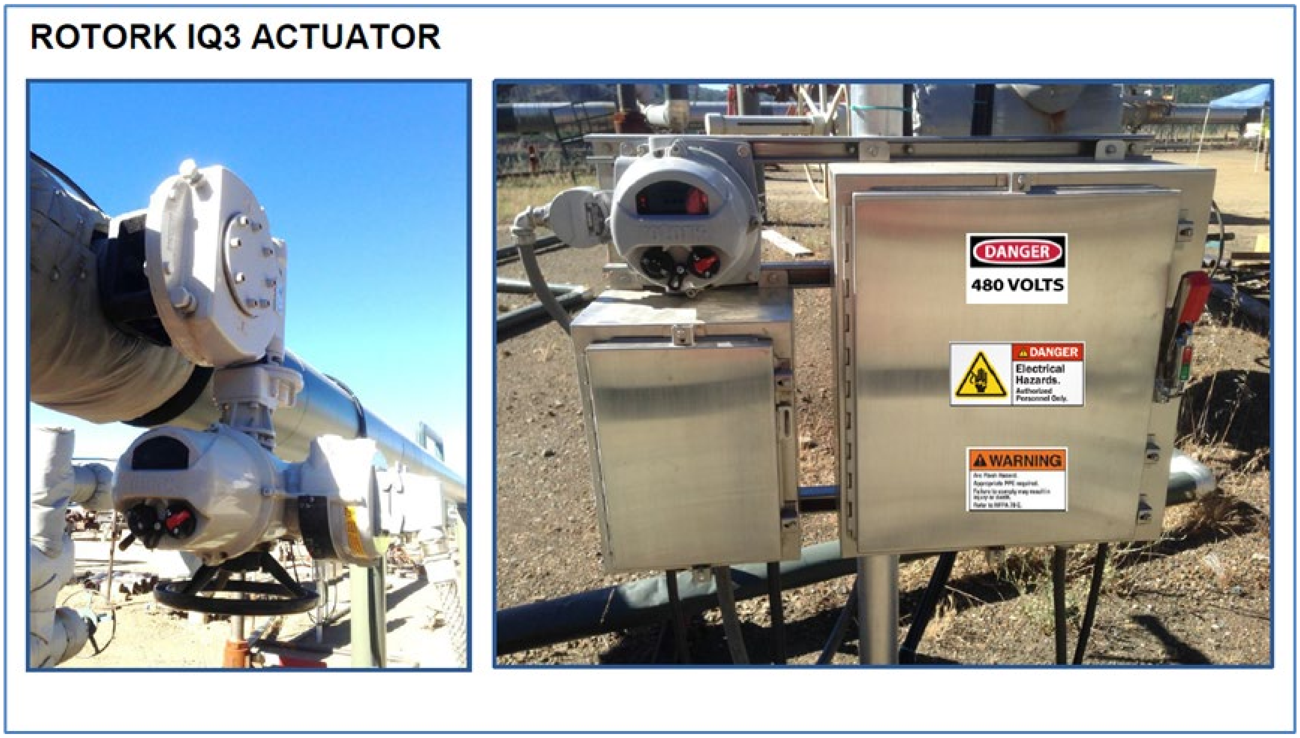
Steam Well Throttle Valve Actuators

New actuators are needed on many steam wells to replace the existing non-functional 30–40-year-old AUMA actuators. Problems with the AUMA actuators include motors and controls that have failed or are failing. ROTORK IQ3 was chosen as the best actuator for our needs. Vortex meters and upgraded steam well valve actuators are needed for flexible generation. During power plant load cutbacks the steam well flowrates can drop below the orifice meter range.

Vortex meters and ROTORK actuators were installed on 10 steam wells in the Sonoma steamfield that previously had no actuators. Functionality tests were done on the combined vortex meter and actuator on each Sonoma well, stroking the valves 100% to 0% and confirm actuator & vortex meter are functioning properly. The next test was a step wise cutback test on each well, cutting back the steam flowrate with 10% valve position reductions and allowing the flowrate to stabilize for about 10 minutes after each valve position change.

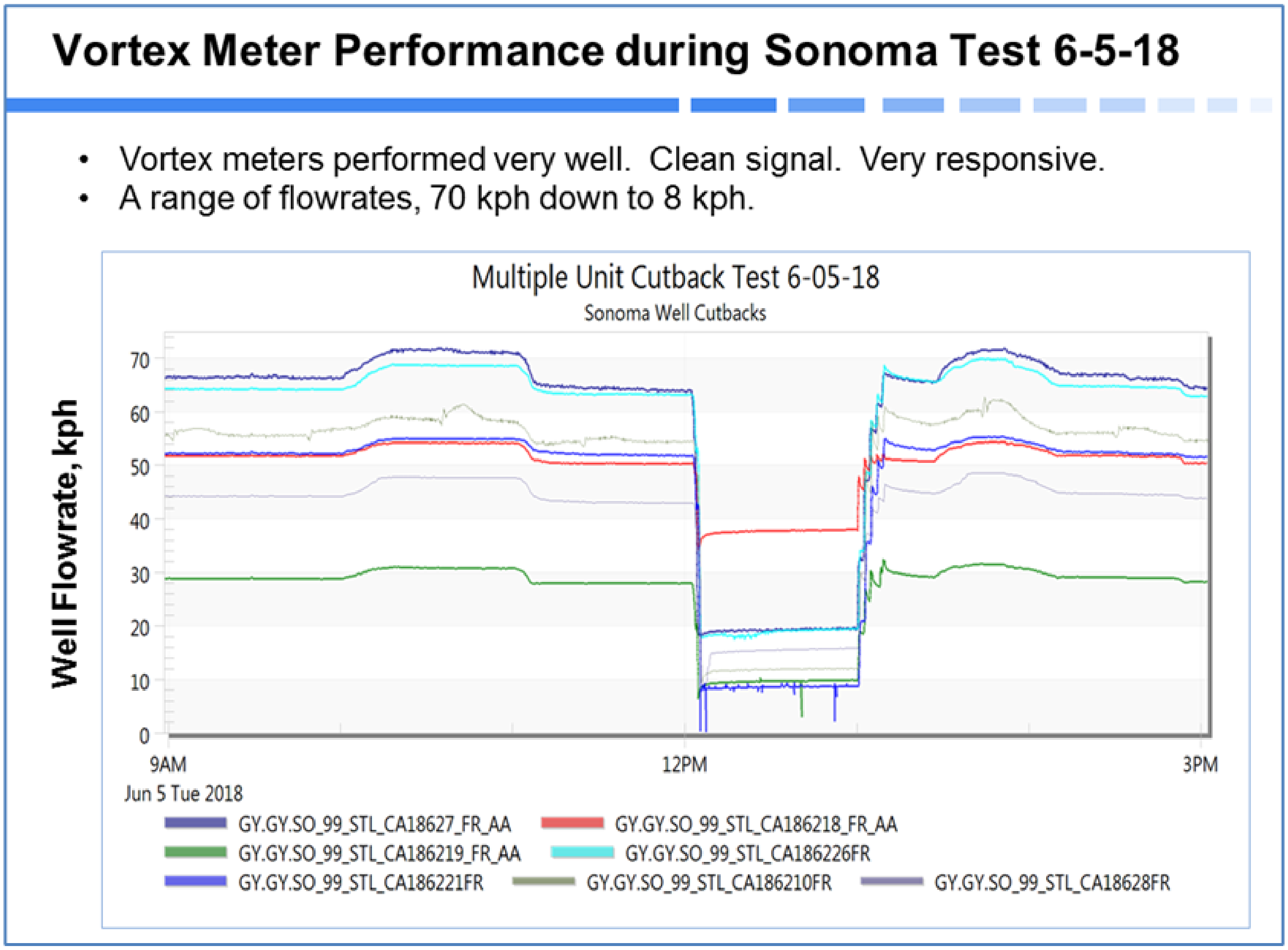
A full Sonoma steamfield cutback test was performed on 6-05-18. The actuators and vortex meters on Sonoma wells performed very well during the test as shown in Figure 21 & 22.

Figure 21: ROTORK IQ3 Actuator with 480V 3-Phase Electric Motor



Source: Geysers Power Company, LLC

Figure 22: Vortex Meter During Sonoma Cutback Test



Source: Geysers Power Company, LLC

Vortex meters tested with remote manual valve position stepwise cutbacks, for example a 10% cutback in valve position every 10 minutes from 100% to 0% and then back up.

Actuators and Vortex Meters Test Results

Vortex meters were installed on ten Geysers wells and successfully demonstrated the capability to accurately measure steam flowrates at much lower values than achievable with orifice metering.

ROTORK actuators were installed on Sonoma wells that had no previous actuators and performed very well. These actuators have state of the art features that improve maintainability and ease of troubleshooting for instrument mechanics.

During power plant load and well flowrate cutbacks the pipeline pressure increases which in turn increases the steam well wellhead pressures and reduces well flowrates.

Future work needed to control steam well flowrates with actuators include:

- Establish flow vs valve position curves for each well. Validate an equation(s) to predict flows based on well deliverability, line pressures u/s and d/s of the valve and valve position.

- Test flow control process control loop on individual wells to set and hold a target minimum flowrate for each well.
- Establish automated multi-well cutback commands on the Distributed Control System (DCS) versus target valve positions.

A summary of systems and components tested during the field-testing portion of the project are given in Figure 23.

Figure 23: Summary of Systems and Components Tested

GEYSERS FLEX GEN FIELD TESTING - SUMMARY

- Steamfield and Powerplant Constraints Identified
  - Individual wells, equipment components tested & characterized
- Actuators & Vortex Meters
  - ROTORK Actuators & Vortex meters overcome limits of orifice meters
- Corrosion Monitoring - sensors installed at Sonoma separator
- Desuperheat System Automation Needed for Flex Gen Operation
  - DSHT system limits identified. Automated system designed & installed
- Burner H2S Abatement System Limits Identified
  - Automated chemical systems installed at U12 and U5&6
- Automated Crossover Valves Needed for Flex Gen
  - Valves installed and function tested in 9 locations
- Turbine Bypasses
  - New turbine bypasses at U5 and U17 installed and tested
  - U5 & U17 TB systems meet their design criteria
  - Turbine bypasses tested and can take each unit to 0 net MW
  - Sonoma TB has limited capacity. Requires steam well suppression and crossover valves to shift steam and expand capabilities.

Source: Geysers Power Company, LLC

CHAPTER 4: Technology/Knowledge/Market Transfer Activities

The success of this project has demonstrated the technical feasibility of flexible generation capabilities at The Geysers. Information from this study will guide future modifications of The Geysers systems as needed to expand current flexible generation capabilities. Project-related information was made available to the public via the publication of peer-reviewed journals, conference papers, presentation, and the final report. Results of this study will be available to other geothermal operators that may be facing similar technical challenges in increasing their flexible generating capabilities.

The knowledge gained from this project has been made available in the following publications:

Publications

- Urbank, Karl. 2016. Investigating Flexible Generation at The Geysers. GRC Bulletin. Sept/Oct 2016.
- California ISO Fast Facts – Impacts of renewable energy on grid operations. CommPR/AG/05.2017 Cal-ISO.
- Hawkins, D. 2007. CAISO's Plan for Integration of Renewable Resources. NARUC Mtg 2007.
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- Finsterle, S., iTOUGH2 User’s Guide, 2017. Report LBNL-40040 (Updated reprint), Lawrence Berkeley National Laboratory, Berkeley, Calif., 2017

CHAPTER 5: Conclusions/Recommendations

Technological Advancement and Breakthroughs

This project has led to technological advancement and breakthroughs for the Geysers power plants and steamfields operated by GPC including upgrades to maintain reliable operation while responding to increased cyclic operations and thereby becoming more "flexible". Advances from this project will assist with the achievement of the State of California's statutory energy goals by helping to sustain the reliable geothermal annual generation that contributes to the Renewable Portfolio Standard (RPS) percent renewables goals.

Specific advances were achieved for each of the key project objectives as follows:

Developing a dynamic and integrated well, pipeline, power plant, and reservoir computer model to optimize steam field management during periods of flexible electrical generation at the Geysers.

The modeling work performed in this project resulted in successful development and application of a simulation-optimization framework for the optimal control of a steamfield under load curtailment. The developed integrated model, which simulates the flow of steam and non-condensible gases and volatile chloride contents from the geothermal reservoir through wells, a pipeline network, and to the turbines of a power plant, was linked to the optimization framework, which allows for automatic minimization of user-defined cost functions that may include penalty terms for violating constraints imposed on the pipeline and power plants. It can be concluded that the simulation framework is a viable tool for the solution of constrained optimization problems for geothermal steamfield operation. The framework can be used for different purposes. Specifically, response surfaces can be generated and visualized, providing valuable insights into the influence of and interactions between control parameters. Moreover, Pareto fronts can be calculated to evaluate the trade-offs between competing objectives. To maximize the usefulness of the application of these modeling tools, it is essential to determine actual benefits and costs associated with production curtailments and violating conditions in the steamfield that are inefficient or potentially detrimental. If these costs and benefits are properly quantified it will enhance the use of the automatic, simulation-based framework in support of steamfield operation. More R&D is needed in this area to create real-time decision-making tools for Operations.

Defining the Geysers' existing and potential limits of electrical generation flexibility in terms of frequency, magnitude, duration and power plant ramp rate.

- Existing operating limits have been defined for the steamfield and power plant systems. Needed upgrades to 1) achieve more reliable operations with current levels of cyclic operation and 2) to expand operating limits for cyclic operations were identified and prototype upgrades were installed and tested.
- Steam well and pipeline corrosion from HCl acid-dewpoint corrosion remains a major limiting factor for increased frequency, magnitude and duration of cyclic operations in the Geysers steamfields.

- High volatile chloride wells are identified and are monitored to maintain minimum steam superheat to avoid severe localized corrosion at the wellheads and upper wellbores.
- Desuperheating /steam-scrubbing systems (DSHT) have a low flow operating limit near P-min level steam flows of about 350 kph per system. DSHT systems must be automated to handle flexible generation with frequent load changes.
- Turbine bypasses are a viable method to overcome steamfield operating limits. However, they create some operating problems for power plant H2S abatement systems.
- Flexible Generation parameters have been defined and evaluated.

Developing accurate low volume steam flow monitoring capabilities at the well heads so that risks of well casing and pipeline corrosion and wellbore formation sloughing posed during the periods of electrical generation curtailment can be accurately understood and avoided.

- Vortex meters and ROTORK actuators installed and tested on 15 wells.
- Low flowrate measurement and flow control on individual wells can be implanted in the future with the upgraded actuators, along with recent DCS control system upgrades. These upgrades will most likely be done selectively over time rather than on all wells.
- Steam wells with wellbore or corrosion risk problems can be addressed individually as needed, for example setting a minimum target flowrate on a well and adjusting valve positions automatically in response to changing pipeline pressures. More testing and development is needed in this area.

Determining mitigation strategies to overcome steam production and delivery issues (i.e. wellbore and pipeline corrosion, production well damage, and water and non-condensible gas accumulation in pipelines), which currently limit the Geysers from responding repeatedly to market and grid conditions.

- GPC's staff teams meet regularly to discuss operating problems and mitigation strategies and provide guidance to O&M crews for well, pipeline and power plant problems. Ongoing detailed case-by-case reviews of problem wells and pipeline operating problems are performed as needed to develop and implement specific action plans.
- Corrosion monitoring and mitigation is an ongoing major challenge. Strategies for dealing with corrosion will build upon current operating practices and R&D efforts. Mitigation strategies include corrosion mitigation facilities (CMF), continuous desuperheating/steam scrubbing (DSHT) upstream of the power plants, improved techniques for remote real-time ultrasonic pipe wall thickness monitoring and steam chemistry monitoring.
- A closer look at Geysers steamfields and power plant operations show they are very dynamic and already routinely respond 24x7 to 5-minute dispatch in response to changing CAISO market and grid conditions. The Geysers power plants successfully operate within their established CAISO P-max and P-min, and ramp rates.
- Increased frequency of cyclic load changes, however, can create operating problems even when operating within the P-max to P-min operating range. Some systems are now operated with manual remote setpoint and require repeated manual adjustment by

operators. An increased frequency of cyclic load changes occurring simultaneously on multiple power plants can exceed the capability of monitoring by an operator and it is not possible to constantly make adjustments on multiple systems.

- Load changes Up and Down cause step changes in operating parameters including steam flowrate, pipeline pressure, steam temperature, steam superheat and changing weighted average steam chemistry. Smoothly handling multiple load changes that require system setpoint adjustments will require automation. For example, upgrading the DSHT system valves and dynamic injection setpoint, and implementing flow control on certain wells.

CHAPTER 6: Benefits to Ratepayers

This project will provide economic benefits to California ratepayers by incrementally expanding the flexible generation capabilities of the Geysers generation facilities to maintain grid reliability and help support additional variable renewables to meet the state's RPS goals. Information from this study will guide future modifications of Geysers systems as needed to expand current flexible generation capabilities.

The technical and economic benefits of this study will come from maintaining the historic reliability of Geysers geothermal generation with the challenging impacts of more frequent load fluctuations. An added benefit comes from achieving incremental increased flexible generation capabilities by expanding the operating range to lower minimum loads. Expanded load following operations will provide economic incentives if risks can be managed and damage to steamfield and power plant facilities largely avoided.

GLOSSARY OR LIST OF ACRONYMS

Term	Definition
CEC	California Energy Commission
EPIC	The Electric Program Investment Charge, created by the California Public Utilities Commission in December 2011, supports investments in clean energy technologies that benefit electricity ratepayers of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company.
RPS	California Renewable Portfolio Standard
GPC	Geysers Power Company, LLC (wholly owned subsidiary of Calpine Corp)
NCPA	Northern California Power Agency
PG&E	Pacific Gas and Electric
LSE	Load Serving Entity
CAISO	California Independent System Operator. www.caiso.com
P-min	CAISO minimum dispatch load for a resource, MW net
BLM	Bureau of Land Management
UT	Ultrasonic Thickness measurement
DSHT	Desuperheat/steam scrubbing system
ADS	Automated Dispatch System
DCS	Distributed Control System. DCS is a computerized system used to monitor and control process variables in steamfields and power plants.
PPA	Power purchase agreement
SRGRP	Santa Rosa Geysers Recharge Project
SEGEP	SouthEast Geysers Effluent Project
NCG	Non-condensible gas
H2S and H2S	Hydrogen sulfide gas. H2S and H2S are used interchangeably as a matter of convenience.