Final Report

KING COUNTY FUEL CELL DEMONSTRATION PROJECT

Prepared for
U.S. Environmental Protection Agency
April 2009

Prepared by

King County
Department of
Natural Resources and Parks
Wastewater Treatment Division

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Table of Contents

Executive Summary ..... **vii**
SECTION 1 Introduction **1-1**
Background 1-1
Project Timeline 1-3
Project Teams 1-3
Report Organization 1-4
SECTION 2 Fuel Cell Technology and Configuration **2-1**
Molten Carbonate Fuel Cell Technology 2-1
Overview of King County's Demonstration Fuel Cell System 2-2
Fuel Processing Block 2-4
Power Section Block 2-7
Power Conditioning Block 2-9
Ancillary Systems 2-9
Fuel Cell Power Plant Configuration 2-10
SECTION 3 Integration of Power Plant with Site Utilities and Fuel Sources **3-1**
Utility Services 3-2
Fuel Gas Systems 3-2
Communications Systems 3-2
SECTION 4 Project Chronology **4-1**
Design and Construction—March 2000 Through March 2004 4-1
Commissioning—March 2004 Through June 2004 4-2
Demonstration Period—June 2004 Through June 2006 4-3
SECTION 5 Power Plant Performance **5-1**
Data Collection Methods 5-1
Performance Summary 5-1
Performance Goal 1—Deliver high quality and quantity of gas to the fuel cell 5-2
Performance Goal 2— Produce energy as designed on natural gas and digester gas 5-3
Performance Goal 3— Produce minimal noise 5-6
Performance Goal 4—Produce energy at a minimal cost 5-7
Performance Goal 5— Produce minimal air emissions while operating on either natural gas or digester gas 5-9
Performance Goal 6—Produce wastewater with no adverse impacts on treatment plant 5-10
Performance Goal 7—Operate the power plant on a continuous basis 5-11
Performance Goal 8—Operate the fuel cell efficiently 5-12
Performance Goal 9—Monitor and control the power plant remotely 5-12
Performance Goal 10—Remove hydrogen sulfide effectively from digester gas 5-12
Performance Goal 11—Dispose of power plant solid waste at a reasonable cost 5-14
Performance Goal 12—Recover waste heat from the power plant 5-15
Performance Goal 13—Demonstrate output turndown on power plant (operation at less than 100 percent capacity) 5-15
Performance Goal 14—Demonstrate power output design ramp rate 5-16
Performance Goal 15—Meet the design service life of the fuel cell stacks 5-16
Performance Goal 16—Confirm ability to restart from a trip condition 5-17
Performance Goal 17—Confirm ability to quickly start the power plant 5-17

SECTION 6 Operational Challenges and Design Improvements 6-1
Integration with Wastewater Treatment Plant Utilities 6-1
Power Plant Module Malfunctions 6-2
Fuel Gas Treatment Systems 6-3
Ancillary Systems 6-3
Power Plant Distributed Control System 6-4
Power Plant Modifications 6-4
SECTION 7 Conclusions and Recommendations 7-1

Tables

Table 1-1. Operations and Testing Project Team — King County Fuel Cell Demonstration Project 1-3
Table 1-2. Peer Review Team — King County Fuel Cell Demonstration Project 1-4
Table 5-1. Summary of Performance Goal Achievement 5-2
Table 5-2. Efficiency Measurement 5-4
Table 5-3. Parasitic Loads 5-5
Table 5-4. Natural Gas Performance Summary 5-5
Table 5-5. Digester Gas Performance Summary 5-5
Table 5-6. Measured Noise Levels (power plant operating on digester gas) 5-7
Table 5-7. King County Labor Hours 5-8
Table 5-8. Materials and Consumables Costs 5-8
Table 5-9. Energy Production Costs and King County Labor Full-Time Equivalents 5-9
Table 5-10. Fuel Cell Power Plant Stack Emission Results While Operating on Natural Gas (Scrubbed Digester Gas) – July 2004 5-10
Table 5-11. Hydrogen Sulfide Sampling Results for Digester Gas Treatment System 5-13
Table 5-12. Results of Gas Chromatography Analysis for Sulfur Compounds in Natural Gas Samples from Desulfurizer Outlet B 5-14
Table 5-13. Power Plant Waste Heat Recovery Unit Performance 5-15
Table 6-1. Power Plant Design Improvements Resulting from Demonstration Project 6-5

Figures

Figure 2-1. Electrochemical Conversions in a Molten Carbonate Fuel Cell 2-2
Figure 2-2. Fuel Cell Power Process Flow Diagram 2-2
Figure 2-3. Fuel Cell System Components 2-3
Figure 2-4. Fuel Cell Operational Schematic 2-11
Figure 2-5. Fuel Cell Installation – Site Overview (southwest corner) 2-11
Figure 2-6. Fuel Cell Installation – Site Overview (southeast corner) 2-12
Figure 2-7. Fuel Cell Installation – Site Overview (northwest corner) 2-12
Figure 3-1. Fuel Cell Demonstration Site—King County South Treatment Plant, Renton, Washington 3-1
Figure 3-2. Fuel Cell Gas Supply—Integration into the South Treatment Plant Gas System 3-3
Figure 5-1. Efficiency Measurement 5-4
Figure 5-2. Noise Measurement Locations 5-6

Appendices

A Fuel Cell Power Plant Process Design Basis
B Demonstration Project Test Plan (July 2004)
C FuelCell Energy Training and Maintenance Manual Summary
D King County South Treatment Plant Fuel Cell Operations Manual (September 2004)
E Power Plant Demonstration Period Data Reporting
F Demonstration Project Public Outreach Summary

Executive Summary

Increasing energy costs, more stringent air emission regulations, and an interest in exploring emerging energy technologies prompted King County, Washington, to search for new and innovative ways to provide electricity for its wastewater treatment plants. In June 2004, the county began a two-year demonstration of a fuel cell power plant to be fueled by gas produced through anaerobic digestion of solids produced at its South Treatment Plant. The project was the first application in the country to use digester gas to fuel a molten carbonate fuel cell.

Molten carbonate is one of the most efficient of the fuel cell technologies under development. Fuel cells produce electric power directly through electrochemical reactions. By avoiding the two-step process of conventional combustion technology, where fuel is first burned and then heat is used to produce power, fuel cells are more energy efficient.

The demonstration project was conceived and implemented through a strong public-private partnership. FuelCell Energy, Inc., provided the power plant and oversaw its operation and maintenance. King County hosted the site, managed the project, and supported operation and maintenance. The U.S. Environmental Protection Agency (EPA) identified a funding source via annual cooperative agreements from the EPA Office of Water.

King County's fuel cell power plant was sized to produce 1 megawatt (MW) of electricity and was designed to capture waste heat from the fuel cell exhaust and return it to the treatment plant. Two project goals were established:

- Demonstrate that the molten carbonate fuel cell technology can be adapted to use anaerobic digester gas as a fuel source.
- Achieve a nominal plant power output target of 1 MW using either digester gas or natural gas.

Both goals were achieved during the two-year demonstration period. A number of secondary objectives (performance goals) were also met. The following table summarizes the performance of the fuel cell power plant.

Performance Summary—King County Fuel Cell Demonstration Project

	Natural Gas	Digester Gas	Total
Operation (hours)	9,013	2,401	11,414
Power generated (million kWh)	7.8	2.1	9.9
Electrical efficiency (%)	42–43	43–44	_
Thermal efficiency (%)	58–62	59–64	_

Only natural gas was used to fuel the power plant during the second year of the project because of excess moisture in the digester gas delivery system.

Testing the digester gas–fueled molten carbonate fuel cell gave FuelCell Energy and King County many opportunities to learn about what is needed to make such applications work well. Power plant shutdowns and their causes provided an environment for highly accelerated life and stress testing at the total system level that will benefit next-generation fuel cell applications, designs, and operations.

Challenges encountered during the demonstration period led to a variety of improvements to the design and operation of the fuel cell plant. FuelCell Energy has incorporated some of these improvements into subsequent fuel cell designs. The challenges centered on mechanical and fuel quality issues. Although the fuel cell module was replaced three times, no issues were identified that would indicate problems with using digester gas to produce energy from molten carbonate technology. The failure of one of the fuel cell module stacks that occurred just after completion of the two-year demonstration and that shut down the plant has been addressed in the vendor manufacturing process, quality inspections, and design specifications.

Problems with digester gas quality, which prevented use of digester gas as a fuel source in the second year of the project, stemmed from the routes and equipment used to convey the gas to the power plant. Modifications were identified and implemented; the last modification was installed at the end of the project before it could be put to use.

It was thought at the start of the demonstration project that if the technology proved successful, King County would consider continuing its operation. From experience gained during the project, the county decided not to continue operating the current configuration. The costs for repair and upgrades, coupled with the fact that FuelCell Energy has substantially improved its newest power plant designs, make total plant replacement a more viable option. The county is considering an alternative that would replace the existing 1-MW power plant with a 300-kW plant. This smaller fuel cell plant would scale better with available digester gas at the South Treatment Plant and would be more portable for possible transfer to other treatment plants.

SECTION 1

Introduction

Fuel cells produce electric power directly through electrochemical reactions using air and fuels such as natural gas, landfill gas, propane, and gas produced from treating wastewater solids (digester gas). By avoiding the two-step process of conventional combustion technology, where fuel is first burned and then heat is used to produce power, fuel cells are more energy efficient. Molten carbonate is one of the most efficient of the fuel cell technologies under development.

Municipal wastewater treatment plants produce solids that are typically treated through anaerobic digestion. The digestion process generates gas that is about 60 percent methane and 40 percent carbon dioxide. Most small plants simply burn the gas in a flare. Larger plants reuse the digester gas onsite for heat or power. Some plants remove the carbon dioxide and sell the resulting pipeline-quality natural gas.

King County, Washington, operates regional wastewater treatment plants and a conveyance system that collects wastewater from 34 local jurisdictions, including Seattle. Increasing energy costs, more stringent air emission regulations, and an interest in exploring emerging energy technologies prompted King County's Wastewater Treatment Division to search for new and innovative ways to provide electricity and heat for its wastewater treatment plants. In June 2004, the county initiated a two-year project at its South Treatment Plant in Renton, Washington, to test the performance of a molten carbonate fuel cell power plant fueled by anaerobic digester gas. The demonstration power plant was designed to produce 1 megawatt (MW) of electricity and to capture and use waste heat from the process.

This report documents the demonstration project, from initial conception through construction, commissioning, and operation. This section of the report provides background on the project, a brief project timeline, project team members, and a description of the contents of other sections of the report.

Background

King County began its investigation of molten carbonate fuel cells for electric power generation in 1997. Working with MC Power Corporation, the county participated in a study of the application of fuel cells using digester gas as the fuel supply.[1] This study suggested that as many as 400 treatment plants in the United States produce enough digester gas to generate at least 1 MW of electricity with a high-temperature molten carbonate fuel cell. Many plants could generate substantially more power. These encouraging results led to a proposal from MC Power to stage a demonstration project at King County's South Treatment Plant.

[1] *Evaluation of Molten Carbonate Fuel Cells Using Anaerobic Digester Gas at Municipal Wastewater Treatment Plants in the United States*, 2007, CH2M HILL, prepared for M-C Power Corporation.

Originally constructed in 1965, the South Treatment Plant has experienced numerous upgrades and expansions. Its current capacity is 115 mgd (average wet-weather flow). The plant provides full secondary treatment of wastewater using an activated sludge process. The effluent discharges through a deep marine outfall into Puget Sound. Solids are treated in four digesters using mesophilic anaerobic digestion. The county recycles all biosolids produced from the digested solids. The raw digester gas is scrubbed to remove carbon dioxide, water, and contaminants and then sold to the local utility as pipeline-quality natural gas. South plant has the potential to generate electricity using gas turbines and to generate heat using boilers. The boilers currently provide heat for treatment plant processes.

The demonstration project was conceived and implemented through a strong public-private partnership. MC Power and King County worked together to identify and secure grant funding for the project. The U.S. Environmental Protection Agency (EPA) identified a funding source via annual cooperative agreements from the EPA Office of Water. Strong support from a Washington State delegation, in particular from former U.S. Senator Slade Gordon and current U.S. Senator Maria Cantwell, helped to secure funding from this source. The Washington State University Energy Extension Office and U.S. Congressman Adam Smith also assisted in funding efforts.

With the availability of EPA funding, King County entered into an agreement with MC Power in May 1999 to design and construct a 1-MW high-temperature molten carbonate fuel cell power plant that would use digester gas produced at South Treatment Plant. The design process was well under way when MC Power went out of business. The company lost U.S. Department of Energy funding after the department determined that it could continue to fund only two of the original three firms that were conducting fuel cell research.

Through a competitive process, King County selected FuelCell Energy (FCE), Inc., in 2000 to continue the demonstration project. Under the terms of the agreement, FCE was to design, supply, and install the power plant; oversee operations and maintenance; share costs; and cover any unanticipated cost overruns. King County was to host the site and manage the project, including construction. The county hired a consultant to prepare the site, connect the power plant to treatment plant utility systems, and monitor and report on power plant operations.

Two project goals were established to measure fuel cell performance at the plant:

- Demonstrate that the molten carbonate fuel cell technology can be adapted to use anaerobic digester gas as a fuel source.
- Achieve a nominal plant power output target of 1 MW (net AC) using either digester gas or natural gas.

Both goals were achieved during the two-year demonstration period (2004–2006). A number of secondary objectives (performance goals) were identified. A test plan with performance metrics was defined to guide the evaluation of the technology during the operational period.

All three partners benefited from the project. King County gained experience in operating and maintaining a fuel cell. FCE was able to test the design of its DFC 1500

fuel cell plant in a municipal/industrial setting and to thereby gain a greater understanding of which design features are important to successful operation and which need to be improved. EPA helped to demonstrate the application of fuel cell technology at U.S. wastewater treatment plants and the potential of fuel cells as a clean air technology of the future.

Project Timeline

A brief timeline for the project from design through demonstration is as follows:

2001	Preloading of the power plant site with fill material.
2001–2002	Power plant design.
2002	Power plant construction and fuel cell stack manufacturing.
Late 2002	Factory testing of power plant in Connecticut.
2003	Installation of reinforced concrete foundation and routing of utilities.
Late 2003	Delivery of power plant equipment to the site.
March 2004	Completion of installation.
April–June 2004	Power plant commissioning and initial emissions testing.
Late June 2004	Beginning of the two-year demonstration.
July 2006	End of the two-year demonstration.

Project Teams

Two teams were established to develop the project: an operations and testing team and a peer review team.

Operations and Testing Team

Table 1-1 identifies operations and testing team members and their roles and responsibilities.

Table 1-1. Operations and Testing Project Team — King County Fuel Cell Demonstration Project

Name	Title	Responsibility
Greg Bush	King County Project Manager	Oversight of FCE and consultant contracts
Eddie Tate	King County Construction Manager	Oversight of construction
Mike Fischer	King County South Treatment Plant (STP) Manager	Wastewater Treatment Plant Manager
Rick Butler	King County STP Process Control	Process Control Supervisor
Carol Nelson	King County STP Process Control	Main contact for fuel cell operations
Frank Stratton	King County STP Maintenance	Main contact for fuel cell maintenance
Lewis Canada	King County STP Lead Operator	Lead facility operator; main contact for fuel cell operations
Jim Gagosz	FCE Project Manager	Oversight of FCE team

Name	Title	Responsibility
Dan Beachy	FCE Field Service Supervisor	Oversight of commissioning, testing, and operations
Jamie Mordarski	FCE Team Leader	Onsite supervision during commissioning, testing, and operations
Winston Spencer	FCE Team Leader	Onsite supervision during commissioning, testing, and operations
Eleanor Allen	Initial Consultant Team Project Manager	Oversight of consultant team
Jaimie Hennessy	Final Consultant Team Project Manager	Oversight of consultant team

Peer Review Team

The peer review team consisted of industry experts from many different arenas, including academia, local and national government, the wastewater industry, air permitting agencies, and utility companies (Table 1-2). The team developed the testing plan, reviewed testing results, and revised the test plan accordingly. It met four times, in November 2003, September 2004, June 2005, and December 2006.

Table 1-2. Peer Review Team — King County Fuel Cell Demonstration Project

Name	Affiliation
Steve Behrndt	Portland Bureau of Environmental Services, Operations Manager
Gordon Bloomquist	Washington State University Energy Program
William H. Hahn	Science Applications International Corporation (SAIC)
Lory Larson	Southern California Edison
Charles Chamberlain	Humboldt State University, Schatz Energy Research Center
Ron Spiegel	Environmental Protection Agency, Cincinnati Research Center
Steve Van Slyke	Puget Sound Clean Air Agency
Dick Finger	King County West Point Treatment Plant
John Spencer	CH2M HILL
Dan Rastler	Electrical Power Research Institute (EPRI), Distributed Energy Resources Program

Report Organization

The remainder of this report is organized into the following sections:

- **Section 2, Fuel Cell Technology and Configuration**—Describes molten fuel cell technology, the components and functions of the power plant at the South Treatment Plant, and the configuration of these components on the site.
- **Section 3, Integration of Power Plant with Site Utilities and Fuel Sources**—Describes how the power plant was connected to treatment plant utilities and power plant fuel sources.

- **Section 4, Project Chronology**—Presents a summary of the project, from design through the two-year demonstration period.
- **Section 5, Power Plant Performance**—Presents the performance goals and metrics used to evaluate the power plant and tracks how well the power plant met these goals and metrics.
- **Section 6, Operational Challenges and Design Improvements**—Reviews the demonstration project in terms of challenges and opportunities, describes how the challenges were addressed, and offers suggestions for design of future fuel cell power plants.
- **Section 7, Conclusions and Recommendations**—Summarizes project successes and challenges and presents recommendations for future work.
- **Appendices –** Present supporting documentation from the demonstration project:
    - A – Fuel Cell Power Plant Process Design Basis
    - B – Demonstration Project Test Plan (July 2004)
    - C – FuelCell Energy Training and Maintenance Manual Summary
    - D – King County South Plant Fuel Cell Operations Manual (October 2004)[2]
    - E – Power Plant Demonstration Period Data Reporting
    - F – Project Public Outreach Summary

[2] Because of its length, Appendix D is not included in the printed version of this report. The appendix can be found on the attached CD, which contains the contents of the entire report.

SECTION 2

Fuel Cell Technology and Configuration

The purpose of this section is to describe the King County demonstration project's fuel cell system. It begins with a brief description of molten carbonate fuel cell technology, followed by an overview and then details of components, functions, and configuration of the county's project-specific system.

Molten Carbonate Fuel Cell Technology

Fuel cells produce electrical power directly through an electrochemical reaction using hydrogen and oxygen. The electrochemical conversion of hydrogen to direct current is much more efficient than if the hydrogen were combusted using the two-step process of conventional combustion in which fuel is first burned and then the subsequent heat is used to produce power. Unlike combustion technologies, fuel cells have very low emissions of carbon monoxide, nitrogen oxides, and non-methane organic carbon. The main product of the fuel cell reaction is water, which discharges in the exhaust gas.

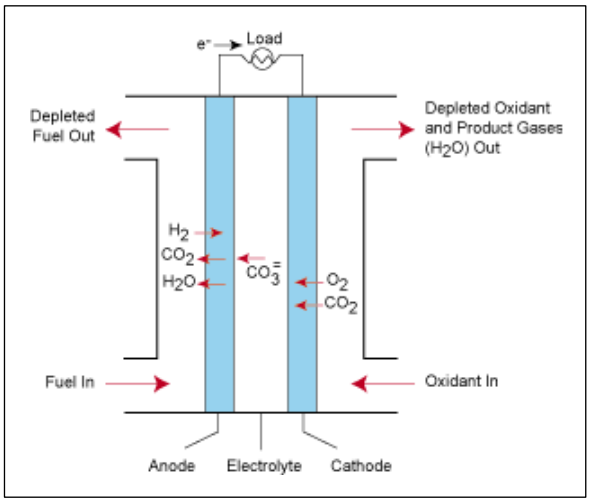
Hydrogen is produced from methane, the primary compound in natural gas, landfill gas, or anaerobic digester gas; air provides the oxygen. Similar to a battery, the fuel cell houses hundreds of individual cells. Cells are grouped to form stacks. Each stack contains an anode, cathode, and electrolyte. When the fuel gas is combined with steam in the presence of a catalyst, the fuel gas is reformed to hydrogen, which is then fed to the anode while air is fed to the cathode.

There are several types of fuel cells. Each is characterized by its electrolyte composition, operating temperature, and electrochemical process. The King County demonstration project used molten carbonate fuel cell technology. Molten carbonate is one of the most energy efficient fuel cell technologies. It can directly convert hydrogen from a variety of fuels and is not prone to carbon monoxide "poisoning" that can occur at lower temperature fuel cells. The air and fuel inputs into the process generate electrical power along with waste heat, gas, and water. Most exhausts and wastes from the process are recycled, with negligible emission. As a high temperature technology, the molten carbonate fuel cell is suited to industrial and commercial applications where heat recovery adds value.

Figure 2-1 shows the electrochemical conversions that take place in a molten carbonate fuel cell. Carbonate salts serve as the electrolyte in a molten carbonate fuel cell. Operating at a temperature of 1,100°F, the salts melt and conduct carbonate ions ($CO_3^=$) from the cathode to the anode. At the anode, hydrogen (H_2) reacts with the ions to produce water (H_2O), carbon dioxide (CO_2), and electrons (e^-). Electrons travel through an external circuit and return to the cathode. At the cathode, oxygen (O_2) and carbon dioxide recycled from the anode react with the electrons to form carbonate ions that replenish the electrolyte and transfer current through the fuel cell.

Further information on molten fuel cell technology can be found in technical publications such as the *Fuel Cell Handbook* produced by the U.S. Department of Energy.[3]

Figure 2-1. Electrochemical Conversions in a Molten Carbonate Fuel Cell



Process Reactions:

$CH_4 + 2H_2O \rightarrow CO + 3H_2$ (methane reforming reaction)

$H_2O + CO \rightarrow H_2 + CO_2$ (shift reaction)

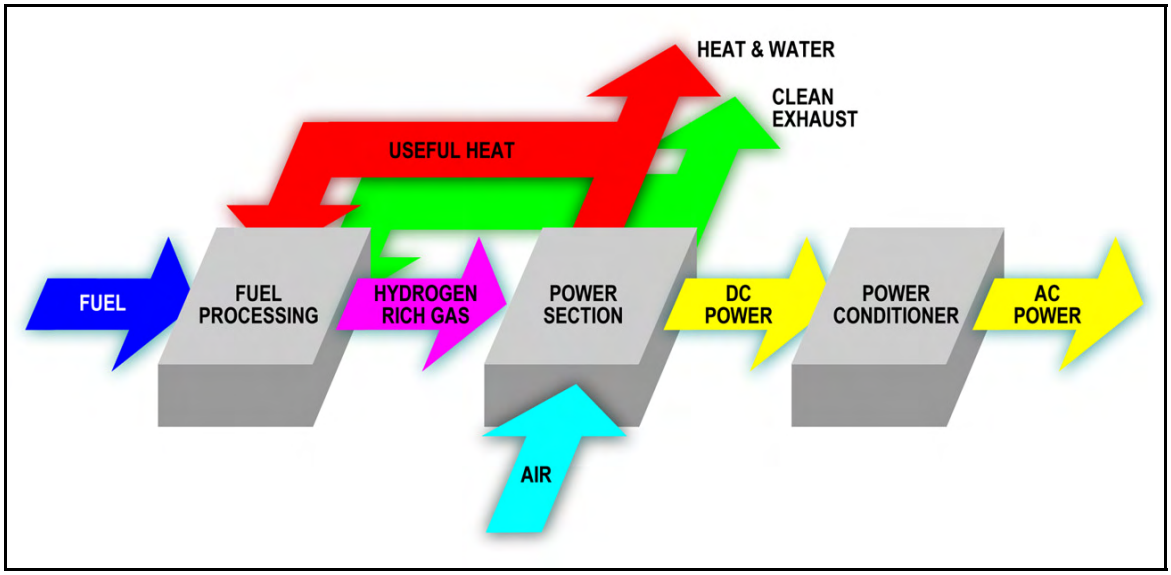
$H_2 + CO_3^{2-} \rightarrow H_2O + CO_2 + 2e^-$ (anode half-cell reaction)

$CO_2 + 1/2O_2 + 2e^- \rightarrow CO_3^{2-}$ (cathode half-cell reaction)

Overview of King County's Demonstration Fuel Cell System

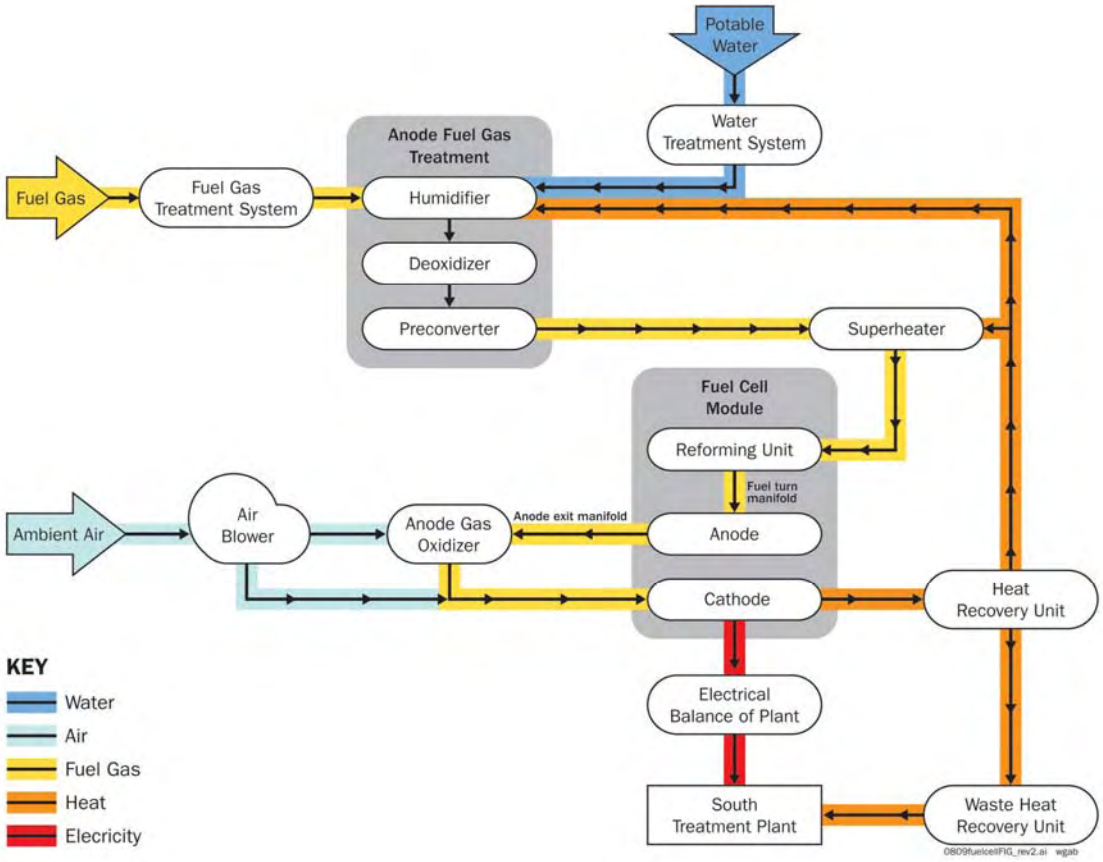
King County's 1-MW demonstration fuel cell system ("power plant") consisted of the systems in the fuel processing, power section, and power conditioning "blocks" and of ancillary systems that supplied water, air, and other materials required to operate the plant (Figure 2-2 and Figure 2-3).

Figure 2-2. Fuel Cell Power Process Flow Diagram



[3] National Energy Technology Laboratory. 2005. University Press of the Pacific.

Figure 2-3. Fuel Cell System Components



In addition to using digester gas, the fuel cell power plant used natural gas that was produced by scrubbing the digester gas onsite ("scrubbed digester gas") or that was supplied by the local utility ("utility natural gas"). The power plant ran on only one fuel at a time. If instrumentation, mechanical, or control problems occurred in the gas scrubbing system, the gas was flared because it did not meet the local utility's specifications and only gas supplied by the utility was fed to the fuel cell. Fuel treatment systems removed compounds from both the digester gas and natural gas that could obstruct the process and damage system components.

In the fuel cell, high temperatures and steam converted each gas to hydrogen before the hydrogen was fed to the anode. At the cathode, oxygen and carbon dioxide recycled from the anode reacted with the electrons in the electrolyte to form carbonate ions that replenished the electrolyte and transferred current through the fuel cell. Cathode exhaust gas traveled to a heat recovery unit where it was distributed as a heat source for the fuel cell plant and the anaerobic digesters at the treatment plant.

The power plant ancillary equipment was sized to generate up to 1.5 MW to take advantage of future fuel cell stack technology advances. A power conditioning system converted DC power from the fuel cell module to AC power for export to the treatment plant. The power plant was also capable of exporting electricity to the regional power grid.

The following sections describe the components and functions of the fuel processing, power section, and power conditioning blocks and of the ancillary systems. Appendix A provides more information on the basis for the process design.

Fuel Processing Block

The fuel processing block consisted of the following systems:

- Natural gas treatment system
- Digester gas conditioning and treatment system
- Anode fuel gas treatment

Natural Gas Treatment System

Natural gas was supplied to the demonstration power plant by the South Treatment Plant's high-pressure scrubbed digester gas header located in the digestion system area. In addition, a backup natural gas source was added by re-aligning the local natural gas utility treatment plant connection. The natural gas treatment system removed sulfur contaminants from natural gas at near-ambient temperature in cold gas desulfurizers and removed carbonyl sulfide (COS), which was present in the utility natural gas, in a COS removal vessel. The desulfurized gas was used for anode fuel gas and as fuel to the anode gas oxidizer's main burner and pilot. Specific functions of the natural gas treatment system were as follows:

- **Monitored gas flow and reduced gas pressure to 15 psig.** The natural gas from either source passed through a custody transfer station adjacent to the power plant. The station contained filtering, flow monitoring, and pressure reduction equipment. The gas entered the power plant through a manual isolation valve and a pressure control valve. The pressure control valve reduced the gas pressure to about 50 psig. A second pressure control valve further reduced the gas pressure to 15 psig to maintain a nearly constant pressure in the downstream cold gas desulfurizers.
- **Heated the gas.** An electric heater raised the temperature of the natural gas to 60°F to ensure optimum performance of the downstream cold gas desulfurizers.
- **Removed sulfur compounds from the gas.** Natural gas flowed through a vessel loaded with COS removal media and then through two cold gas desulfurizers that operated in series. The desulfurizers were designed to remove sulfur compounds (mostly hydrogen sulfide, but also trace amounts of carbon disulfide (CS_2), sulfur dioxide (SO_2), mercaptans, sulfides, disulfides, and thiophenes) from the natural gas to less than 0.1 part per million by volume (ppmv). The sulfur removal extended the operating time of the fuel cell power plant.

  The quantity of sulfur compounds that could be adsorbed on the beds depended on the bed operating pressure and temperature and the inlet gas flow and composition. Each of the beds was estimated to have sufficient capacity to desulfurize the feed gas at rated conditions for six months of operation.

  The vessels were loaded with the following media:

  - COS vessel—1,500 pounds of Engelhard CNG-2 catalyst
  - First-stage cold gas desulfurizer—560 pounds of Engelhard CNG-1 catalyst

- Second-stage cold gas desulfurizer—310 pounds of Norit RGM-3 9Cu impregnated activated carbon

Digester Gas Treatment System

Digester gas was supplied to the demonstration power plant by the South Treatment Plant's low-pressure digester gas header located at the waste gas burner. The gas was then treated to make it suitable for use as fuel for the fuel cells. The digester gas treatment system performed the following functions:

- **Compressed digester gas to about 26 psig.** The compression system included a variable speed drive gas compressor, a digester gas feed knockout drum at the compressor suction, and a digester gas aftercooler and discharge knockout drum at the compressor discharge. Condensed liquids removed from the digester gas were returned to the treatment plant sanitary sewer.
- **Filtered oil from the compressed gas**. Downstream of the compressor system, a high efficiency oil filter reduced entrained oil in the gas to less than 0.5 ppmv.
- **Removed sulfur compounds from the gas.** The cooled and compressed digester gas passed through a first-stage media bed for bulk hydrogen sulfide removal, which was designed to reduce hydrogen sulfide content to less than 10 ppmv. The gas continued through two digester gas polishers to remove trace sulfur compounds and siloxane. The polishers were designed to remove the remaining sulfur compounds (mostly hydrogen sulfide) to less than 0.1 ppmv.

  The bed and polishers were loaded with the following media and carbon:

  - The first-stage media bed contained 18,000 pounds of SulfaTreat® media with an estimated capacity, at rated conditions, for nine months of operation.
  - The first-stage and second-stage gas polishers contained 12,000 pounds of potassium hydroxide–impregnated activated carbon and 1,600 pounds of non-impregnated activated straight-chain carbon.

Carbon in both gas polishers was estimated to have a life expectancy of three to six months based on continuous operation under fuel gas rated conditions.

See the digester gas conditioning section of Appendix A for more detail.

Anode Fuel Gas Treatment

Following removal of sulfur contaminants from the fuel gas, the gas traveled to the anode fuel gas treatment system. This treatment system consisted of the humidifier, deoxidizer, and preconverter shown in Figure 2-3. The gas was simultaneously humidified and superheated, deoxidized, reformed to remove heavy hydrocarbons to prevent carbon deposition in the fuel cell stacks, and then superheated again. These functions are described as follows:

- **Humidified and superheated the gas.** The *fuel humidifier,* which was part of the heat recovery unit, used waste heat recovered from the fuel cell cathode exhaust and purified water from the water treatment system to simultaneously heat and humidify the fuel gas to meet the temperature requirements of the downstream anode fuel treatment equipment. Heating was controlled to generate a fuel gas

temperature of at least 900˚F. The fuel humidifier capacity was controlled by bypassing a portion of the cathode exhaust gas around the fuel humidifier's tube bundle.

- **Treated the preheated fuel gas to remove oxygen.** The fuel gas from the fuel humidifier was routed to the *fuel deoxidizer,* which catalytically reacted with free oxygen (O_2) in the fuel gas. Oxygen removal was required to prevent oxidation of the preconverter and fuel cell catalysts. Although oxygen was not expected to be present in the scrubbed digester gas, the raw digester gas contained up to 1.4 percent oxygen by volume. Trace amounts of oxygen may also have been present in the utility natural gas supply. The oxygen was consumed by oxidizing methane (digester gas) or high molecular weight (C_2^+) hydrocarbons (natural gas) in the fuel to form carbon dioxide and water. The exothermic oxygen removal reactions heated the gas as it passed through the fuel deoxidizer.
- **Partially reformed the deoxidized fuel gas.** The fuel gas leaving the fuel deoxidizer was routed to the *preconverter.* The preconverter reformed, without heat loss or gain, all of the high molecular weight hydrocarbons and a small fraction of the methane in the fuel gas to form hydrogen, carbon monoxide, and carbon dioxide. Eliminating higher weight hydrocarbons prevented carbon deposition in the fuel cell stacks and established a small excess of hydrogen gas to ensure a reducing environment at the inlet to the fuel cell reforming units.

  The gas cooled as it passed through the preconverter as a result of endothermic reforming reactions. The degree of temperature change indicated performance level of the preconverter. A temperature drop of 175–250°F was normal, whereas a smaller temperature drop indicated loss in catalyst activity (potentially due to sulfur poisoning or oxidation). A very small temperature drop or a rise in temperature indicated that the catalyst had been oxidized and that oxygen was present and reacting with fuel gas in the preconverter.
- **Removed catalyst fines.** The preconverter effluent gas was routed to an *after-filter* to remove catalyst fines that may have carried over.
- **Superheated the preconverter effluent gas.** Fuel gas moved from the after-filter to the *fuel superheater,* which was a part of the heat recovery unit. In the superheater, the gas was heated to the temperature required by the fuel cell module using waste heat recovered from the cathode exhaust. Operation of this heater was not controlled; its performance (including fuel gas outlet temperature) depended entirely on process conditions and heat exchanger surface area. The temperature of the fuel gas exiting the fuel superheater normally remained between 980°F and 1,070°F during all power generation and standby operating conditions. The superheated gas was fed to the anode fuel gas inlet of the fuel cell stack module through an insulated heat-traced pipe. The heat tracing was designed for high temperature operation to limit anode fuel gas heat loss and to ensure that the gas temperature remained above 970°F.

Power Section Block

The power section block consisted of the oxidant supply system and the fuel cell module.

Oxidant Supply System

The oxidant supply system consisted of an air blower and an anode gas oxidizer (Figure 2-3). The system integrated the operation of the fuel cell anodes and cathodes during power generation by (1) using the residual fuel energy and heat in the anode exhaust gas to heat air to the required oxidant gas temperature and (2) recirculating the carbon dioxide generated in the fuel cell anodes to the fuel cell cathodes to support the cathode reactions.

The system performed the following functions:

- **Compressed ambient air to be used as cathode oxidant.** The *air blower* was a rotary air compressor with a variable speed drive to provide a wider range of operation. The blower supplied up to 5,000 standard cubic feet per minute (scfm) of air to the anode gas oxidizer. The blower also provided cooling air to the flame detector and oxidizer sight glasses.
- **Mixed the compressed air with anode exhaust gas and catalytically oxidized the fuel components in the anode exhaust gas.** Anode exhaust gas from the fuel cell module was routed to the *anode gas oxidizer,* where the remaining fuel components in the low-BTU anode gas were catalytically oxidized with air to generate carbon dioxide, water vapor, and heat. The oxidizer consisted of a natural gas burner and fuel piping train, a thermal reactor, and a catalytic reactor. The burner used desulfurized natural gas to provide supplemental heating of the compressed air/anode exhaust gas stream.
- **Delivered the hot oxidant gas to the cathode side of the fuel cell stack module.** The carbon dioxide generated in the anode gas oxidizer was fed to the cathode at the flow rate and temperature required for various fuel cell module operating modes.

Fuel Cell Module

The fuel cell module consisted of four 250-kW vertical stacks, each with approximately 400 cells, contained inside one vessel. Each stack housed a *reforming unit, anode, and cathode* (Figure 2-3). The reforming unit combined the desulfurized fuel gas (either natural gas or digester gas) with treated water to produce a fuel gas/steam mixture suitable for feeding as anode fuel gas to the fuel cell stack module. The steam served as a reactant in both the fuel cell module and the anode gas preconverter for the reforming and shift reactions that generated hydrogen from the methane fraction of the fuel.

The cells were stacked in series, each producing nearly 1 volt; the total voltage leaving each stack approached 400 VDC. The stacks were designated as Stacks A, B, C, and D.

The following controls and instrumentation guided operation of the fuel cell module:

- **Temperature control.** Overall temperature of the fuel cell stack module was controlled through the oxidant supply system. During plant heat-up and plant cool-down modes, a temperature ramp generator provided the temperature set-points for the anode gas oxidizer effluent/cathode inlet gas. During power generation and hot standby modes, oxidizer air flow was controlled to maintain the stack temperature between preset inlet and outlet limits while attempting to maximize the overall module temperature.

  The temperature of the anode fuel gas entering the fuel cell module was not controlled. It depended on the temperature and flow of cathode exhaust gas through the fuel superheater. (See the earlier discussion on the anode fuel gas treatment system.)

- **Pressure control.** There were no pressure controls in the fuel cell module. Pressures in the fuel cell module were the result of the accumulated system pressure drops through the plant. The pressure difference between the anode inlet/outlet and the cathode inlet was closely monitored as an indication of the level of potential leakage from the anodes to the cathodes across the cells.

- **Voltage control.** The fuel cell module included instrumentation for monitoring the voltages of individual cells and the voltages generated across groups of cells in the individual stacks.

- **Fuel utilization control.** During power generation, the fuel gas flow rate and power (current) drawn from the fuel cell stack module were carefully coordinated. A significant deviation between target and actual fuel use triggered an alarm. It was critical that the fuel cell stacks not be starved of fuel during any operation. Such fuel starvation could reduce the life and performance of the stacks. The amount of power that could be safely drawn from the fuel cell module directly depended on the theoretical hydrogen content (TH_2) of the fuel gas feed stream. The TH_2 of the fuel gas stream was the maximum amount of hydrogen that could be generated from the fuel gas, based on 100 percent completion of the hydrocarbon reforming and shift reactions. The fraction of the fuel gas stream's TH_2 that was allowed to react within the fuel cell anodes to generate electric power was the fuel utilization (U_f).

- **DC power controls.** The electrical outputs of the four fuel cell stacks were connected in parallel to a common DC bus. The positive (cathode) terminal was resistance grounded. The stacks were electrically isolated by blocking diodes. The DC current could be converted to either 400 VAC or 150 VAC. In both cases, the inverter outputs were then connected to the 480-VAC power system via step-up isolation transformers.

Power Conditioning Block

The electrical balance of plant (EBOP) was an outdoor non-walk-in enclosure containing the power conditioning system (PCS), DC power fuses, DC grounding circuit, DC isolation diodes, AC utility interconnection circuit breaker and protective relaying, distributed control system (DCS), uninterruptible power supply (UPS), and low-voltage distribution equipment.

The PCS converted DC power from the fuel cell stack modules to AC power for export and to meet the plant's auxiliary loads. The PCS inverters employed pulse width modulation of the power semiconductors to provide AC electric power at 480 V/3-phase/60 Hz that met the requirements of IEEE 519.[4]

The fuel cell power plant was rated at 1 MW, with a net output at 480 VAC. The output was tied to a transformer to step-up the voltage to 13,090 V at the South Treatment Plant's main substation. The fuel cell output used a 3,200-amp breaker as the tie breaker in conjunction with protective relays to provide the system interconnection protection. The protection included over/under voltage and frequency, over current phase and ground, directional ground fault, and sync-check. Even though the electrical power did not leave the treatment plant, the local utility required compliance with its interconnection protection specification.

Ancillary Systems

The demonstration power plant housed several ancillary systems integral to the operation and control of the power plant: a water treatment system, instrument air system, and nitrogen gas supply system. In addition, a heat recovery system was designed to capture exhausts and waste heat for subsequent use in power plant fuel treatment systems and in the South Treatment Plant heat loop.

Water Treatment System

The water treatment system supplied deionized water to the fuel gas humidifier. Fuel cell specifications required further treatment of the potable water available at the treatment plant. A packaged USFilter water treatment system was installed to meet finished water specifications. The system included pretreatment (consisting of an activated carbon filter, a jel cleer media filter, twin water softeners with brine tank, a chemical injection station, and cartridge filtration), a reverse osmosis unit, a continuous deionization unit, three mixed-bed service deionization units, a deionized water storage tank, and water transfer pumps. Several different types of media were used in the water treatment system, including granular activated carbon, water softener resin, and silica quartz.

Instrument Air System

The instrument air system supplied dry compressed air to pneumatically operated valves, the oxidizer burner for use as pilot air, and various panels for purging contents. The system consisted of redundant oil-free rotary scroll-type air compressors, air pre-

[4] IEEE = Institute of Electrical and Electronic Engineers.

filters, air dryers, and air receivers. A local control panel allowed for monitoring and process automation.

Nitrogen Gas Supply System

The nitrogen gas supply system provided low-pressure nitrogen gas for purging operations and for protecting the fuel cell module during plant shutdowns. The nitrogen was provided in six-packs of high pressure gas bottles and distributed through pressure reducing regulators and automated valving.

Nitrogen gas was used to purge the following equipment:

- The fuel gas piping and fuel cell anodes prior to the startup
- The fuel gas piping prior to and following maintenance activities
- The cold gas desulfurizers and digester gas treatment vessels prior to media change-out

During power plant shutdowns, the nitrogen gas provided (1) an inert gas curtain in the fuel cell cathode exit piping to avoid a vacuum condition in the stack as the module cooled and (2) a constant purge of the fuel gas piping and fuel cell anodes to avoid nickel carbonyl formation (in the preconverter and the fuel cell reforming units) and condensation.

A liquid nitrogen system with vaporizer was used for purging the fuel cell stack module during long-term shutdown of the power plant.

Heat Recovery Unit and Waste Heat Recovery Unit

As shown in Figure 2-3, cathode exhaust gas from the fuel cell stack module was routed to the "shell" side of the heat recovery unit, where it was used as the heat source for the fuel superheater and fuel humidifier. A waste heat recovery unit (WHRU) was installed on the heat recovery unit's exhaust stack. The WHRU was designed to provide 1.4 MBTU/hr of supplemental heat to the South Treatment Plant's process heat loop. The system consisted of hot water loop pumps, control valves, a heat exchanger, and a hot air blower. When given a permissive signal from the fuel cell power plant, the WHRU provided supplemental heat during fuel cell power generation.

Fuel Cell Power Plant Configuration

Figure 2-4 shows a schematic of the fuel cell system components and auxiliary equipment for the 1-MW demonstration project. Site photographs in Figure 2-5, Figure 2-6, and Figure 2-7 show installed views of the power plant.

Figure 2-4. Fuel Cell Operational Schematic

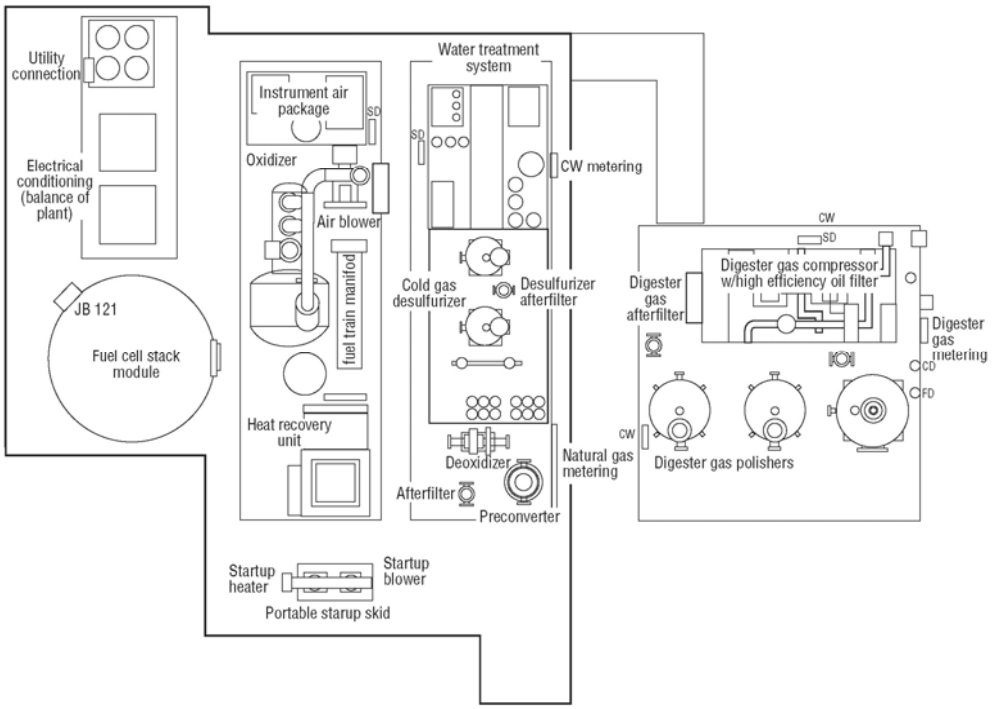


Figure 2-5. Fuel Cell Installation – Site Overview (southwest corner)

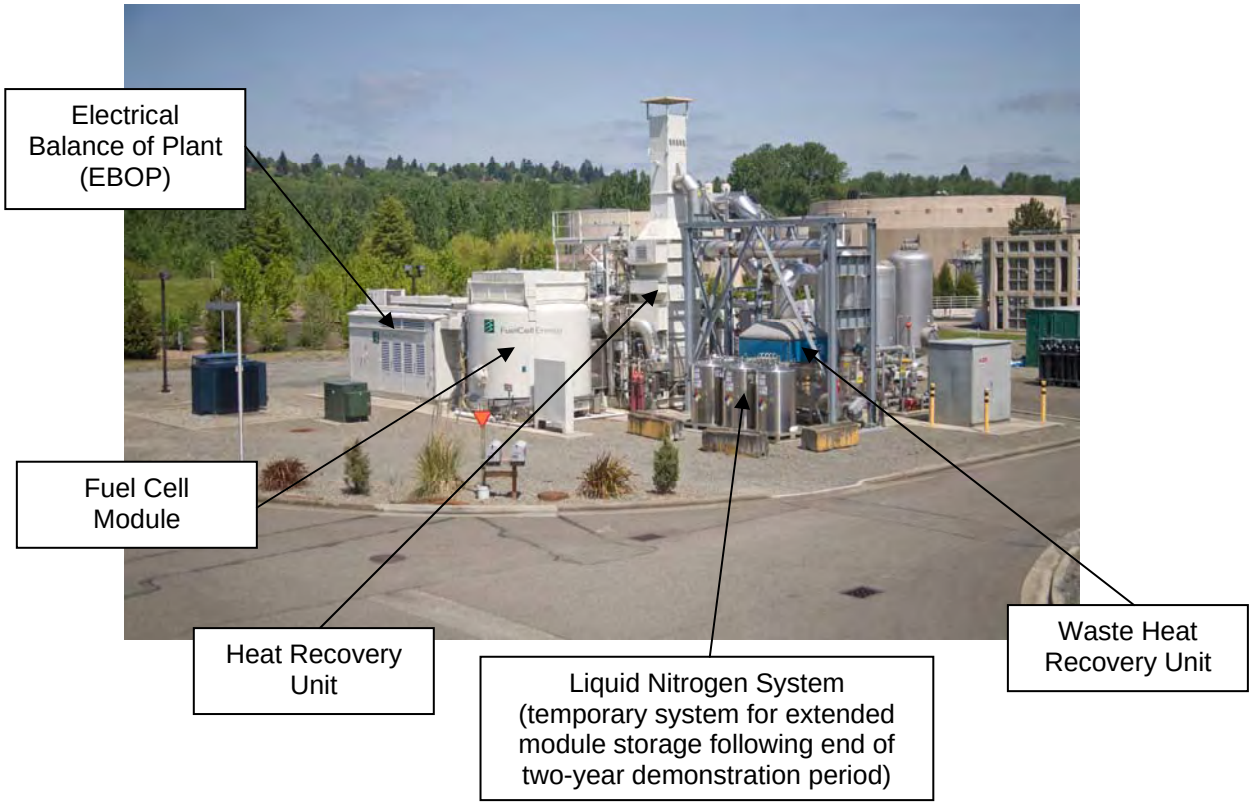


Figure 2-6. Fuel Cell Installation – Site Overview (southeast corner)

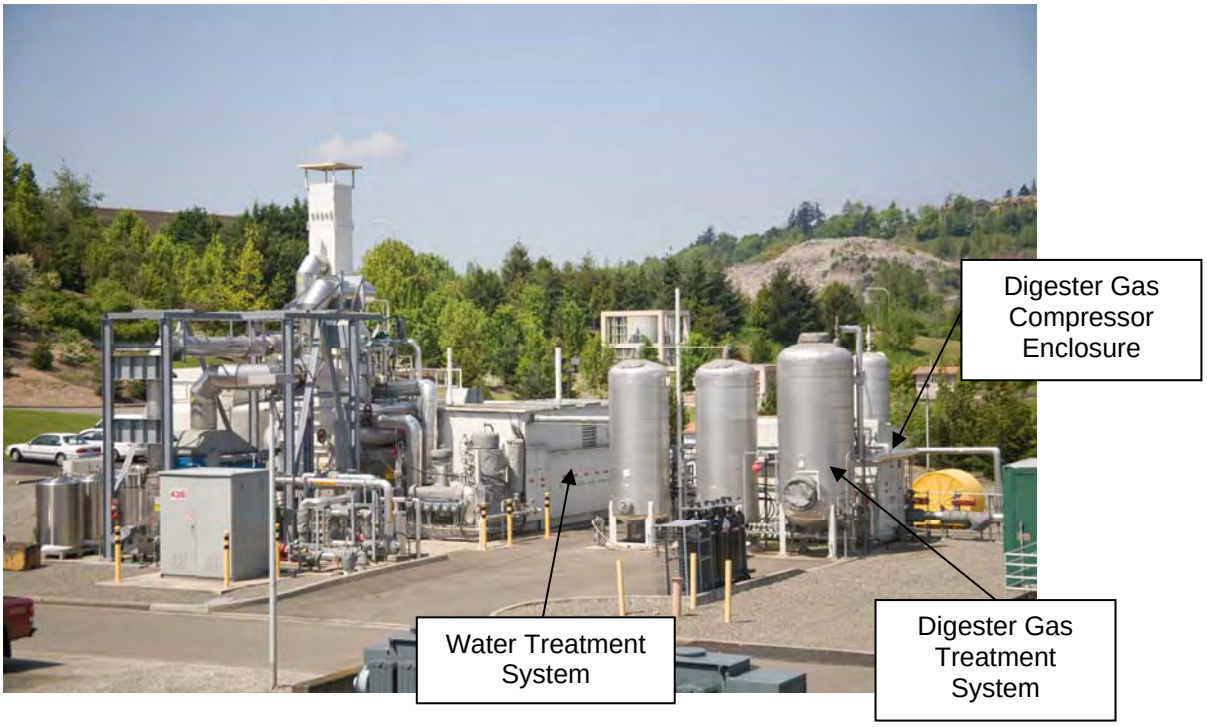


Figure 2-7. Fuel Cell Installation – Site Overview (northwest corner)

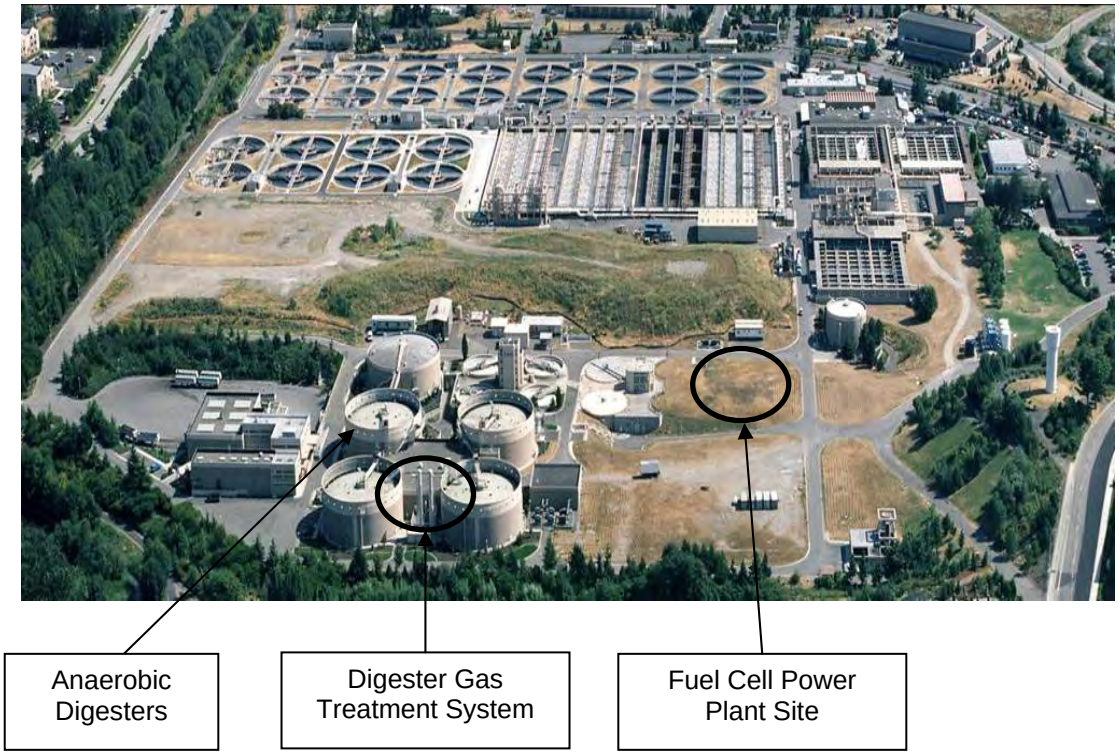
SECTION 3

Integration of Power Plant with Site Utilities and Fuel Sources

The fuel cell power plant was located at the South Treatment Plant on a half-acre site adjacent to the solids processing facilities and close to required utilities. The site was large enough to house the power plant and to provide a staging area for site preparation and power plant installation. Figure 3-1 shows the fuel cell demonstration site before power plant installation.

The fuel cell design required several interfaces with the treatment plant, including connections to utility services, fuel gas systems, and communications systems. This section describes these interfaces.

Figure 3-1. Fuel Cell Demonstration Site—King County South Treatment Plant, Renton, Washington



Utility Services

The fuel cell power plant required potable and cooling water, power, and sewer connections:

- Potable water was supplied to the power plant to meet water requirements for power generation. FuelCell Energy (FCE) designed the power plant water treatment system based on an analysis of the quality of potable water supplied to the treatment plant (see Appendix A). To reduce consumption of potable water, treatment plant reclaimed water, which is generated by coagulation and filtration of treatment plant secondary effluent, served as the source for power plant cooling water.
- A 480-VAC power supply from the treatment plant supplied power to power plant equipment during periods when the fuel cell power plant was not generating power (startup, shutdown, and standby).
- The fuel cell power plant was connected to the treatment plant sanitary sewer system for continuous discharge during normal operation of the reject/regeneration/backwash water from the power plant's water treatment system. When the power plant operated on digester gas, the digester gas treatment system generated cooling water and condensate that also discharged to the sewer system.

Fuel Gas Systems

Figure 3-2 schematically represents the integration of the fuel cell power plant into the treatment plant's digester gas system and the local utility's natural gas supply.

The anaerobic digesters are located approximately 1,000 feet from the fuel cell power plant. The digesters feed gas through large pipes to a header, which feeds into a gas scrubbing system (Binax system) adjacent to the digesters. Digester gas was provided to the power plant by connecting the plant to the existing treatment plant gas system. Digester gas was routed in a buried 12-inch-diameter pipe from the treatment plant waste gas burners; scrubbed digester gas was tapped from an existing 3-inch-diameter natural gas line to the local utility. The delivery pressure ranges to the fuel cell power plant were 7–10 inches water column for the digester gas and 240–260 psi for the scrubbed digester gas.

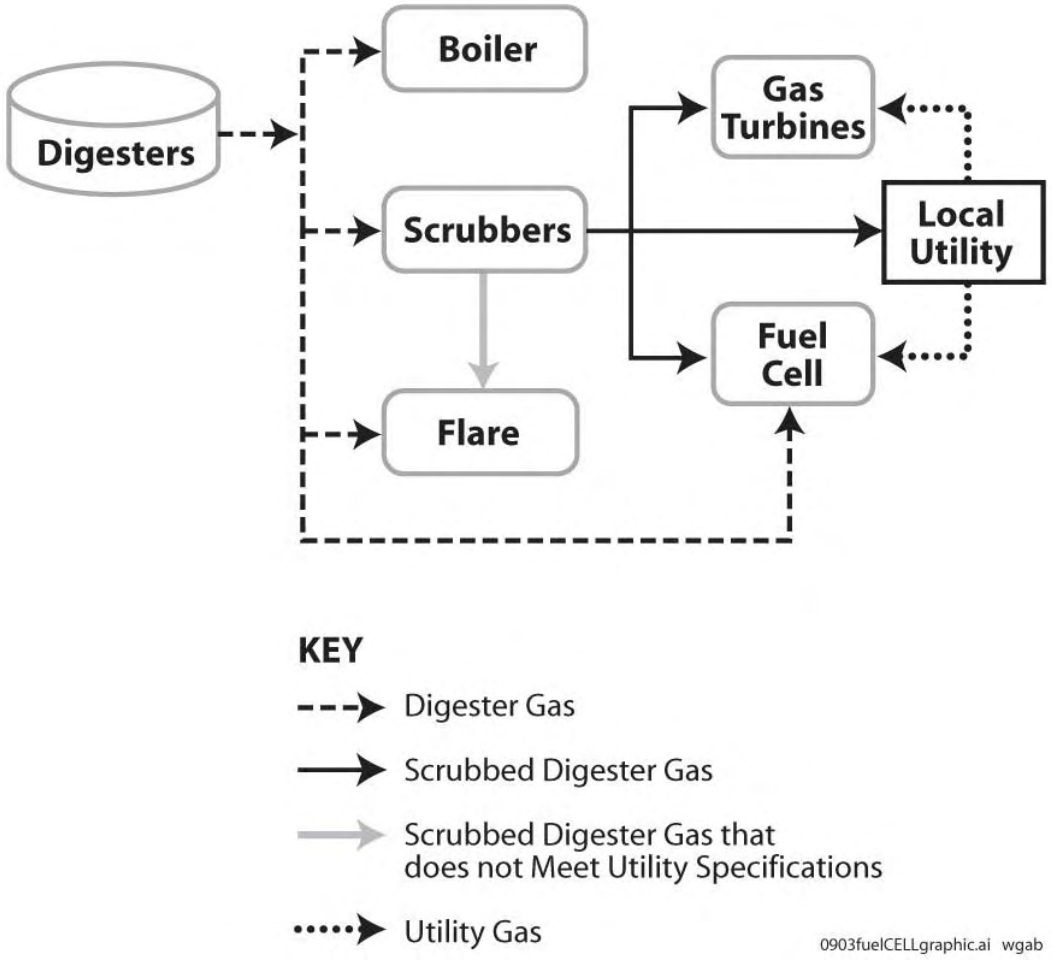
During power plant commissioning, King County and the local natural gas utility realigned the utility natural gas piping so that the natural gas could be used as a backup to the scrubbed digester gas.

Communications Systems

Communications between the fuel cell power plant and the treatment plant included discrete permissive signals, alarm signals, a gas scrubbing system divert signal to initiate the fuel switch control logic (digester gas to natural gas), and direct connection of the power plant fire alarm panel to the treatment plant fire alarm system.

Treatment plant staff could remotely monitor the power plant at a Web site accessed through a standard browser. FCE staff could remotely monitor and control the power plant through a telephone modem located at the power plant and the use of PC Anywhere software.

Figure 3-2. Fuel Cell Gas Supply—Integration into the South Treatment Plant Gas System



SECTION 4

Project Chronology

The design, construction, and commissioning of the 1-MW demonstration power plant took place from 2000 through the first quarter of 2004. FuelCell Energy (FCE) and King County shared design and construction responsibilities. FCE was responsible for power plant delivery; King County was responsible for treatment plant site preparation and equipment installation.

The two-year demonstration period began in June 2004 and ended in June 2006. Initially, FCE field staff operated and maintained the fuel cell power plant with support from King County South Treatment Plant staff. Following training by FCE staff, King County staff assumed operation and maintenance responsibilities.

This section presents a brief project chronology, from design through the end of the demonstration period, to aid in understanding performance and assessment data presented in subsequent sections.

Design and Construction—March 2000 Through March 2004

In March 2000, King County hired a consultant to design the power plant site and the waste heat recovery system. Following design, King County executed a construction contract to prepare the site and install the fuel cell power plant. The treatment plant site was preloaded with fill material in 2001.

In January 2001, King County signed a contract with FCE to design the fuel cell power plant. FCE designed and constructed the fuel cell module and contracted with Fluor Daniel to design and construct the remainder of the demonstration power plant. Power plant manufacture was completed in 2002 and factory testing was conducted at FCE's site in Connecticut in late 2002. During design of the power plant, gas quality data and potable water quality data were collected and forwarded to FCE. These data are included in the process design basis document (Appendix A).

Construction started in 2003 with the installation of the reinforced concrete foundation and the routing of utilities. In the construction contract, the 1-MW demonstration power plant was identified as owner-furnished equipment. In late 2003, FCE delivered the equipment to King County who turned it over to the construction contractor for installation. FCE was then responsible for system testing and power plant commissioning.

The project team faced four major challenges during construction and commissioning of the fuel cell power plant:

- Prior to installation, water was discovered in the fuel cell module and the module was replaced. Installation was completed in March 2004.

- Because the fuel cell was not isolated from the electric grid, the team had to coordinate with the local electric utility for interconnection. To comply with local utility and national interconnection rules, the fuel cell power plant was designed to sense when variations in voltage and frequency in the grid exceeded certain thresholds and to stop generating power when these variations occurred. In addition, an interconnection agreement with the electric utility was required for revenue collection. The agreement was established to define different rates through revenue class metering.
- Permit approvals had to be obtained from the local jurisdiction. The local electrical inspection authority was not familiar with fuel cells; the assigned inspector was familiar with the National Electrical Code (NEC), which applies to residential fuel cells but not to the class of direct fuel cell installed for the demonstration project. The fuel cell power plant equipment skids arrived onsite without Underwriters Laboratory (UL) or Canadian Standards Association (CSA) certification. FCE added the CSO certification labels after assembling the plant. A third-party was contracted to perform an independent code inspection of the installed power plant. The third-party inspection identified several deficiencies that required remedial actions. The inspection and ongoing dialogue with the local electrical inspection authority led to approval of required permits.
- Most of the equipment skids required a considerable amount of rework by FCE technicians. Construction and assembly of the fuel cell ancillary equipment skids led to prolonged commissioning of equipment.

Commissioning—March 2004 Through June 2004

Power plant commissioning began in March 2004. The purpose of the commissioning was to monitor the performance of the fuel cell system and to reach a stable level of operation. By the end of June 2004, FCE staff had completed the commissioning and the first phase of emissions testing. Highlights of the commissioning are as follows:

- **Commissioning—Scrubbed Digester Gas Operation.** Between March 25 and April 7, FCE operated the power plant using scrubbed digester gas. Operation ceased on April 7 because of interruptions of the scrubbed digester gas fuel supply and failure of a power plant fuel flow control valve. The interruptions occurred for various reasons, including maintenance of the digester gas scrubbing system.
- **Plant Modifications to Accommodate Backup Natural Gas Supply.** To ensure a steady supply of fuel to the power plant, King County and the local natural gas utility realigned the utility natural gas piping so that natural gas could be used as a backup to scrubbed digester gas. The natural gas connection was completed in early June. The power plant's scrubbed digester gas treatment system was modified to accommodate the utility natural gas. The natural gas contained high levels of carbonyl sulfide (COS), which could damage the fuel cell. Special copper and aluminum oxide media were temporarily installed in the two existing cold gas desulfurizer vessels. Design began on a new COS removal vessel that would treat both scrubbed digester gas and utility natural gas upstream and in series with the existing desulfurizers.

- **Commissioning—Natural Gas Operation.** From June 11 through June 20, the power plant was commissioned while operating on utility natural gas.

Demonstration Period—June 2004 Through June 2006

The two-year demonstration project began on June 30, 2004. During this period, the fuel cell power plant operated on both digester gas and natural gas (either scrubbed digester gas or utility natural gas). It generated power 65 percent of the time—a total of 2,401 hours on digester gas and 9,013 hours on natural gas. Modifications to the power plant gas supply, excess moisture in the digester gas supply, unrelated treatment plant outages for other projects, and failure of a fuel cell module were major factors in limiting the power plant hours of operation.

Throughout the demonstration period, power plant operating parameters were continuously recorded. In addition, various plant process streams were sampled to evaluate impacts and performance. Plant sampling and testing results in relation to performance goals are presented in Section 5; the testing plan is included in Appendix B. Operations and maintenance challenges are highlighted in Section 6.

Third Quarter 2004—July 2004 Through September 2004

Third quarter 2004 was characterized by power plant operation on all three types of fuel: (1) first on natural gas in order to complete emissions testing, (2) then digester gas followed by scrubbed digester gas when digester gas quality was found to be unreliable, and (3) then back to digester gas. Highlights of the quarter are as follows:

- **Natural Gas Operation at Full Power.** The fuel cell operated on utility natural gas at 100 percent output through the first half of July 2004.
- **Emissions Testing.** On July 27 and July 28, California Air Resources Board (CARB) emissions testing was conducted while the power plant was operating on scrubbed digester gas. Exhaust stack nitrogen oxides, carbon monoxide, and non-methane hydrocarbons were measured over one-hour intervals at 50, 75, and 100 percent power levels.
- **Digester Gas Operation, with Fluctuations in Gas Quality.** On August 2, FCE began operating the power plant with digester gas as the fuel source. The gas supply was constant, but the gas quality varied. When scrubbed digester gas did not meet utility specifications for sale, it was diverted into the treatment plant waste gas burner piping for flaring. This piping also carried the raw digester gas to the fuel cell power plant. When the piping carried both scrubbed and raw digester gas, the methane content of the raw digester gas to the fuel cell increased from approximately 65 to 85 percent over a three-hour period. These changes in fuel composition exceeded acceptable limits for reliable fuel cell operation.
- **Scrubbed Digester Gas Operation at Full Power.** On August 5, fuel supply to the fuel cell was switched to scrubbed digester gas so that alternatives could be evaluated for addressing the problem of gas quality variability in the raw digester gas feed. From August 5 through September 3, the fuel cell operated at 1 MW on scrubbed digester gas. The fuel cell operated in hot standby mode for a two-day

period in mid August to implement control logic modifications to the stack control modules.[5]

- **Digester Gas Operation at Full Power with Some Interruptions.** To verify fuel cell operation on digester gas, a short run was conducted from September 4 through September 12. During this period, the plant operated at 100 percent power but experienced several plant trips as the result of digester gas compressor shutdowns. Each trip required that the fuel cell be ramped back to 100 percent power.
- **Three-Week Shutdown and Control Logic Modifications.** On September 13, the power plant was shut down for a planned three-week electrical outage unrelated to the fuel cell demonstration project. During the shutdown, the power plant control logic was modified to allow automated switching of gas supplies without interruption in power generation. FCE developed a new control logic to allow continued power plant operation when scrubbed digester gas was being diverted for incineration. The logic allowed the power plant to automatically switch from digester gas to utility natural gas when it received a divert signal from the treatment plant.

Fourth Quarter 2004—October 2004 Through December 2004

Highlights of fourth quarter 2004 are as follows:

- **Control Logic Modifications.** Modifications to control logic to allow automated switching of gas supplies continued during early October. The control logic modifications were commissioned from late October through December 16.
- **Preparing to Install the COS Vessel.** During this quarter, the new COS vessel was delivered, a concrete pad and gas piping were installed to accommodate the vessel, and design work associated with scrubbing COS from utility natural gas was initiated.
- **Operation at Full Power Using Digester Gas.** Following implementation of the new control logic, the fuel cell operated at full power from December 16 through the end of the quarter. This period included eight continuous days of full power generation on digester gas.
- **Treatment Staff Training.** FCE staff started to train treatment plant personnel on operations and maintenance of the fuel cell power plant. (A summary of the maintenance training manual is included in Appendix C, and the operations training manual is included in Appendix D.)

First Quarter 2005—January 2005 Through March 2005

During this quarter, the fuel cell operated on both digester gas and natural gas (either utility natural gas or scrubbed digester gas). The operation focused on maximizing the operating time on digester gas, but several events forced a switch to natural gas. Highlights of the quarter are as follows:

- **Interruptions in Digester Gas Supply.** On two occasions, the power plant digester gas flow element failed. These failures led to natural gas operation from January 15 through January 29 and from March 28 through April 9. Natural gas was also used

[5] In hot standby mode, the fuel cell remained at an operational temperature (approximately 1,200°F) but did not generate power. Fuel was used only to maintain the fuel cell temperature.

from March 30 through April 1 while media (SulfaTreat®) in the digester gas treatment system were being replaced. In addition, diversion of scrubbed digester gas for incineration triggered operation on natural gas on eleven occasions for a total of approximately 200 hours.

- **Power Plant Derating**. On March 3, the rated output of the fuel cell was reduced (derated) by two percent, from the maximum output of 1 MW to 980 kW. The fuel cell output was scheduled to be derated periodically over its life to maximize the life of the stacks. The derating was scheduled to occur every six months based on a linear reduction of 10 percent over an assumed three-year life of continuous operation.
- **Commissioning of the Waste Heat Recovery Unit.** The waste heat recovery unit ran intermittently during this quarter. In January, the commissioning of the unit was officially completed.
- **Transfer of Operations and Maintenance to King County Staff.** King County treatment plant staff completed their training in March. Fifteen staff completed the operator training, and eleven staff completed the preventive maintenance training. During this quarter, operation and maintenance responsibilities were transferred from FCE field service personnel to treatment plant staff. Primary operations duties included performing daily equipment checklists and responding to power plant alarms. Maintenance staff performed preventive maintenance and supported FCE's ongoing corrective maintenance activities.

Second Quarter 2005—April 2005 Through June 2005

During second quarter 2005, the power plant operated on digester gas for about five weeks and on natural gas for about seven weeks. The power plant was shut down during the last week of the quarter because of a fuel system imbalance in one of the fuel cell stacks. Highlights of the quarter are as follows:

- **Problems with Digester Gas Supply—Alternation of Natural Gas and Digester Gas Operation.** From April 1 through May 6, the fuel cell operated on natural gas because of a failed digester gas flow element. The failed coriolis flow element was replaced with a thermal mass flow element. Following flow element testing on May 7, the gas supply was switched to digester gas and the fuel cell operated on digester gas until June 14.

  On June 14, the fuel cell plant tripped offline because of excessive water in the digester gas. The volume of water exceeded the capacity of the existing water separation system (knockout drum) upstream of the gas compressor and filled the compressor with water. The knockout drum located downstream of the gas compressor did not fill completely but did capture a significant amount of water. The fuel cell was restarted on natural gas.

  On June 24, the plant responded to a loss of natural gas supply and tripped offline. It was established that the loss of fuel coincided with King County' commissioning of the new COS vessel in the natural gas supply line. Following this event, the plant was returned to operation and a ramp-up on natural gas was initiated.
- **Emissions Testing.** On June 8, emissions sampling was conducted while the power plant operated at 100 percent power on digester gas.

- **Fuel Supply Imbalance—Power Plant Shutdown.** During the power ramping on June 14 to begin operation on natural gas, conditions that indicated a fuel supply imbalance on one of the four fuel cell stacks were observed. Fuel cell performance demonstrated that an operating value of 350 kW could be sustained while the appropriate corrective actions were investigated.

  During the second power ramping on June 24, alarm conditions for fuel cell temperature and voltage deviations suggested that the suspected fuel supply imbalance on one of the fuel cell stacks had worsened. It was determined that return to power operations may result in damage to the fuel cell stack, and steps were immediately taken to cool down the plant. Following data evaluation, the decision was made to replace the fuel cell module.

Third Quarter 2005—July 2005 Through September 2005

The power plant did not operate during third quarter 2005. The fuel cell module was replaced early in the quarter, and startup was delayed to accommodate installation of a cogeneration facility at the treatment plant. Highlights of the quarter are as follows:

- **Installation of the Replacement Fuel Cell Module.** In July, FCE exchanged the existing fuel cell module with a replacement module. Contractors removed the existing module on July 11 and completed installation of the replacement module on July 25. The replacement module was the original module returned to FCE because water was discovered in the module during commissioning.
- **Treatment Plant Fuel and Power Outages.** Restarting of the fuel cell was suspended because of a planned outage related to King County's installation of a cogeneration facility; the outage affected both the gas supply and electric power to the fuel cell power plant. The outage continued through the end of this quarter and most of the fourth quarter.

Fourth Quarter 2005—October 2005 Through December 2005

The power plant resumed operation on December 10. The plant operated on natural gas because of excessive moisture in the digester gas. Highlights of the quarter are as follows:

- **Natural Gas Operation Because of Excessive Moisture in Digester Gas.** On December 1, staff attempted to start the power plant on digester gas. The digester gas compressor shut down because of a high condensate level in the upstream water separator (knockout drum). Troubleshooting was initiated to identify the source of this excess moisture. From December 10 through the end of the quarter, the power plant operated on natural gas.
- **Power Plant Derating.** At the start of this period of operation, the fuel cell was derated to 850kW. Previous operating time served as justification for the derating.
- **Identification of the Source of Digester Gas Moisture.** Troubleshooting for the cause of excess moisture in the digester gas continued through the end of the quarter. A low-pressure gas retention check was performed on the buried gas piping to confirm its integrity. No test gas pressure decay was identified during a one-hour hold period, which indicated that moisture was not being introduced from an external source such as groundwater. The primary cause of the moisture accumulation was judged to be inadequate draining of collected moisture from the

digester gas. The preferred solution was to install a large moisture trap in the section of the treatment plant gas piping located adjacent to the fuel cell power plant.

First Quarter 2006—January 2006 Through March 2006

The power plant operated on natural gas during first quarter 2006 while the moisture trap for the digester gas piping was being designed. Highlights of the quarter are as follows:

- **Natural Gas Operation.** Power plant operation continued on natural gas. The plant tripped to hot standby mode on three occasions. The first two events totaled less than 24 hours. They were caused by communications troubleshooting and loss of power plant pneumatic supply. The third event, involving a failed programmable logic controller, started on March 16 and lasted through the end of the quarter. FCE troubleshot the failed controller both onsite and remotely and then sent field service staff to replace it.
- **Design Completed on the Moisture Trap.** Design of the digester gas moisture trap was completed. The specifications were forwarded to a contractor, who forwarded them to the piping fabricator.

Second Quarter 2006—April 2006 Through June 2006

The power plant operated on natural gas during second quarter 2006 while the moisture trap was being installed. The two-year demonstration period was completed at the end of the quarter. The power plant was scheduled to remain operational beyond this quarter to accumulate additional run time on digester gas. Highlights of the quarter are as follows:

- **Natural Gas Operation.** The power plant operated on natural gas through the entire quarter. The plant tripped to hot standby mode on two occasions, totaling less than 24 hours.
- **Installation of a Moisture Trap.** The digester gas moisture trap was installed at the end of the quarter. Commissioning of the equipment was scheduled for July 2006.

Third Quarter 2006—July 2006 Through September 2006

During third quarter 2006, the power plant briefly operated on natural gas until failure of internal components of one of the fuel stacks prompted final plant shutdown. Highlights of the quarter are as follows:

- **Natural Gas Operation Until Emergency Shutdown.** The power plant operated on natural gas until July 29, when differences in stack current, which resulted from a short, triggered a trip to hot standby mode. The short was caused by a high stack-to-stack current deviation. Following FCE's failed attempt on July 31 to restart the power plant, the stack assembly was allowed to cool for visual inspection.
- **Final Shutdown of the Power Plant.** In late August, FCE staff conducted two inspections of the fuel cell stacks. A bore scope inspection of the hardware confirmed that failure of internal components of one of the four stack assemblies caused a short circuit. It was concluded that the module could not be operated, and the power plant was completely shutdown.

SECTION 5

Power Plant Performance

The fuel cell power plant was monitored throughout the two-year operating period to demonstrate its ability to meet the various performance goals outlined in the testing plan. This section describes data collection methods, performance goals, and metrics used to evaluate the power plant during the demonstration period and documents how well the power plant met these goals. Appendix E provides a summary of power plant performance.

Data Collection Methods

Members of the project team collected and continually evaluated operating data to optimize the operation and maintenance of the power plant. Data collection methods included automated logging of process data on the plant control system, manual logging of parameters on operator checklists, and grab sampling of process flows with subsequent testing for specific constituents.

All operating process parameters were continuously displayed on both local and remote process screens. The plant control system recorded critical process parameters—including fuel gas flow, fuel gas quality, power generation, power consumption, and stack operating temperatures—needed to evaluate whether performance goals were met. FuelCell Energy (FCE) staff reviewed and summarized the data before distributing them to the project operations and testing team. In addition, power plant alarms were captured in an alarm historian and reviewed by the project team.

The team completed daily checklists to monitor and check the performance of subsystems, such as the water treatment system, instrument air system, and waste heat recovery unit, that were equipped with local instrumentation only.

Periodic samples were collected from both gas and liquid process flows. Gas was sampled at the exhaust stack and several points in the fuel gas treatment systems. An outside laboratory completed the exhaust stack testing; members of the operations and testing team conducted the fuel gas treatment system testing. Liquid samples were taken at several points in the water treatment system. Both King County and contracted laboratories conducted the liquid process testing.

Performance Summary

Seventeen performance goals were defined in the project testing plan (Appendix B). Table 5-1 lists these performance goals and indicates whether the goals were met during the demonstration period. The sections that follow provide data and analysis for each goal.

Table 5-1. Summary of Performance Goal Achievement

Performance Goal	Goal Achievement	
	YES	NO
1 – Deliver high quality and quantity of gas to the fuel cell.		X
2 – Produce energy as designed on natural gas and digester gas.	X	
3 – Produce minimal noise.	X	
4 – Produce energy at a minimal cost.		X
5 – Produce minimal air emissions while operating on natural gas or digester gas.		X
6 – Produce wastewater with no adverse impacts on treatment plant.	X	
7 – Operate the power plant on a continuous basis.	X	
8 – Operate the fuel cell efficiently.		X
9 – Monitor and control the power plant remotely.	X	
10 – Remove hydrogen sulfide effectively from digester gas.	X	
11 – Dispose of power plant solid waste at a reasonable cost.		X
12 – Recover waste heat from the power plant.		X
13 – Demonstrate output turndown on the power plant.	X	
14 – Demonstrate power output design ramp rate.	X	
15 – Meet the design service life of the fuel cell stacks.		X
16 – Confirm ability to restart from a trip condition.	X	
17 – Confirm ability to quickly start the power plant.	X	

Performance Goal 1—Deliver high quality and quantity of gas to the fuel cell

Metric: *Acceptable gas supply >95% of the time with digester gas conditions of: BTU content between 550 and 610 BTU/scf, pressure between 4 to 7 inches of w.c., and temperature between 50 and 100°F.*

Performance goal achieved: *No.*

The fuel cell had to rely on natural gas as a backup to digester gas on numerous occasions because the energy or moisture content of the digester gas was too high for power plant operation. The variability in digester gas was caused by design deficiencies in the interface between the power plant and the treatment plant digester gas system.

When scrubbed gas was diverted to the treatment plant waste gas burner, the BTU content of the fuel cell digester gas supply would increase above the design value of 610 BTU/scf and stop power generation. To ensure a steady supply of fuel to the power plant, FCE made control logic modifications in December 2004 so that the fuel source

would automatically switch from digester gas to natural gas in the event of a gas scrubbing system diversion.

Excessive moisture in the digester gas supply led to a shutdown of the digester gas compressor on two occasions. In both cases, the volume of water exceeded the capacity of the existing water separation system upstream of the gas compressor. It took six months to design and install a large moisture trap in the treatment plant gas piping.

Performance Goal 2— Produce energy as designed on natural gas and digester gas

Metric: *Produce 15,000 MWh gross power for 2-year test period – prorate to later half of test after plant normalized during first 6-9 months. In addition, produce 1 MW net power with parasitic electrical loads measured during testing on natural gas and digester gas.*

Performance goal achieved: *Yes.*

The fuel cell power plant operated on natural gas and digester gas for 9,013 hours and 2,401 hours, respectively. Over the two-year test period, a total of 9,885 MWh of net power was generated.[6] A combination of power plant modifications and treatment plant outages prevented the fuel cell from achieving the total power generation goal. Because the power plant operated mostly on natural gas during the last half of the test period, the total power was not prorated as suggested in the metric.

The generation of 1 MW net power was demonstrated on both natural gas and digester gas.

Methods for Calculating Electrical and Thermal Efficiencies

The fuel cell power plant control system recorded fuel consumption and power generation throughout the two-year operating period. The data acquisition system was programmed for a 10-minute sampling rate. Fuel gas was measured with either a Coriolis flow meter (natural gas) or a thermal mass flow meter (digester gas). The plant was equipped with power meters to measure both fuel cell module output and parasitic loads. FCE transferred the raw data collected by the data acquisition system to the onsite project team. Monthly performance data were collected throughout the demonstration period (Appendix E). In addition, waste heat recovery system temperatures were manually recorded during power plant operation.

Efficiency was calculated in four ways, as shown in Table 5-2 and Figure 5-1. Measurements 1 and 2 represent electrical efficiency, which takes into account how much electricity was produced as a function of inlet gas supply; Measurements 3 and 4 represent thermal efficiency, which takes into account the electricity produced and the waste heat recovered.

All efficiency calculations were based on a lower heating value (LHV) of 900 BTU/scf for natural gas and 548 BTU/ft^3 for digester gas. The efficiency calculations were done at full load under standard conditions and include the parasitic loads shown in Table 5-3.

[6] Total gross power produced is unknown. FCE reported total power as net power.

Because variations in ambient temperature impact fuel cell performance and efficiency, the efficiency calculations have an estimated ± 3 percent variance.

Table 5-2. Efficiency Measurement

Efficiency Measurement	Components	Where Calculated on Figure 5-1	How Calculated
1	Power plant operating on natural gas (scrubbed or utility gas)	C/A	electricity out *divided by* natural gas in
2	Power plant operating on digester gas (with digester gas skid losses)	C/(B+E)	electricity out *divided by* digester gas in + compressor power in
3	Heat recovery with power plant operating on natural gas (scrubbed or utility gas)	(C+D)/A	electricity out + heat recovered *divided by* natural gas in
4	Heat recovery with power plant operating on digester gas (with digester gas skid losses)	(C+D)/(B+E)	electricity out + heat energy recovered *divided by* digester gas in + compressor power in

Figure 5-1. Efficiency Measurement

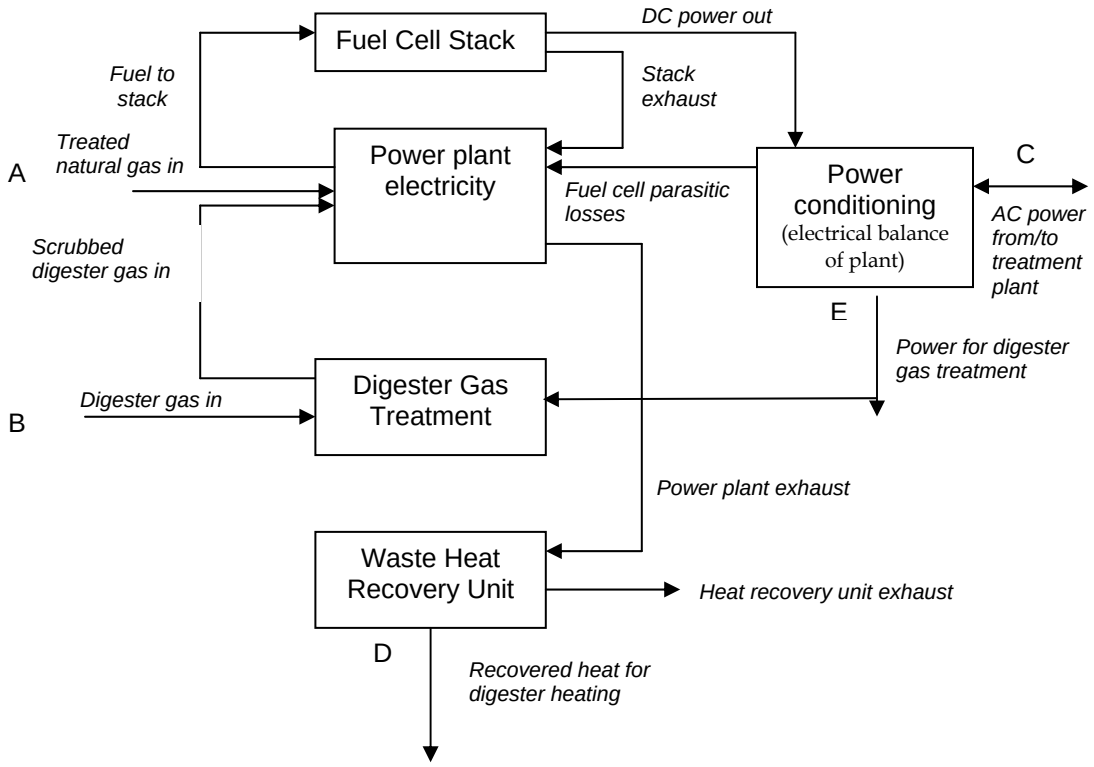


Table 5-3. Parasitic Loads

Fuel Supply	Balance of Plant Loads (kW)	Inverter Losses (kW)	Total Parasitic Losses (kW)
Natural gas	48–53	~37	85–90
Digester gas	55–75	~37	92–112

Electrical Efficiencies for Natural Gas and Digester Gas

Table 5-4 and Table 5-5 show run time, power generated, and electrical efficiency by quarter for natural gas and digester gas. The efficiency was slightly higher for digester gas than for natural gas, because the fuel cell ran at a slightly lower temperature on digester gas and therefore needed less air for cooling. All efficiency numbers reflect operation at full power and include the total parasitic losses shown in Table 5-3.

Table 5-4. Natural Gas Performance Summary

Year	Total	2004			2005				2006	
Parameter		**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**
Run time (hours)	**9,013**	398	1,330	659	903	1,142	0	609	1,800	2,172
kWh generated (million)	**7.75**	0.30	1.20	0.61	0.87	0.96	0	0.48	1.50	1.83
Electrical Efficiency	**43%**	43%	43%	43%	42%	43%	NA[a]	42%	43%	43%

[a] Not operating.

Table 5-5. Digester Gas Performance Summary

Year	Total	2004			2005				2006	
Parameter		**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**
Run time (hours)	**2,401**	_	147	499	1,120	635	_	_	_	_
kWh generated (million)	**2.14**	_	0.10	0.39	1.08	0.57	_	_	_	_
Electrical Efficiency	**44%**	_	44%	44%	43%	44%	_	_	_	_

Note: Fuel cell did not operate on digester gas in Year 2; see Section 4.

Thermal Efficiencies for Natural Gas and Digester Gas

The ranges for thermal efficiencies were 59–64 percent while the plant was operating on digester gas and 58–62 percent while on natural gas. See the discussion for Performance Goal 12 for more information.

Performance Goal 3— Produce minimal noise

Metric: *Noise limits set at (i) 60 dBA at a distance of 100 feet from the fuel cell equipment pads and (ii) 70 dBA at a distance of 10 feet from the fuel cell equipment pads.*

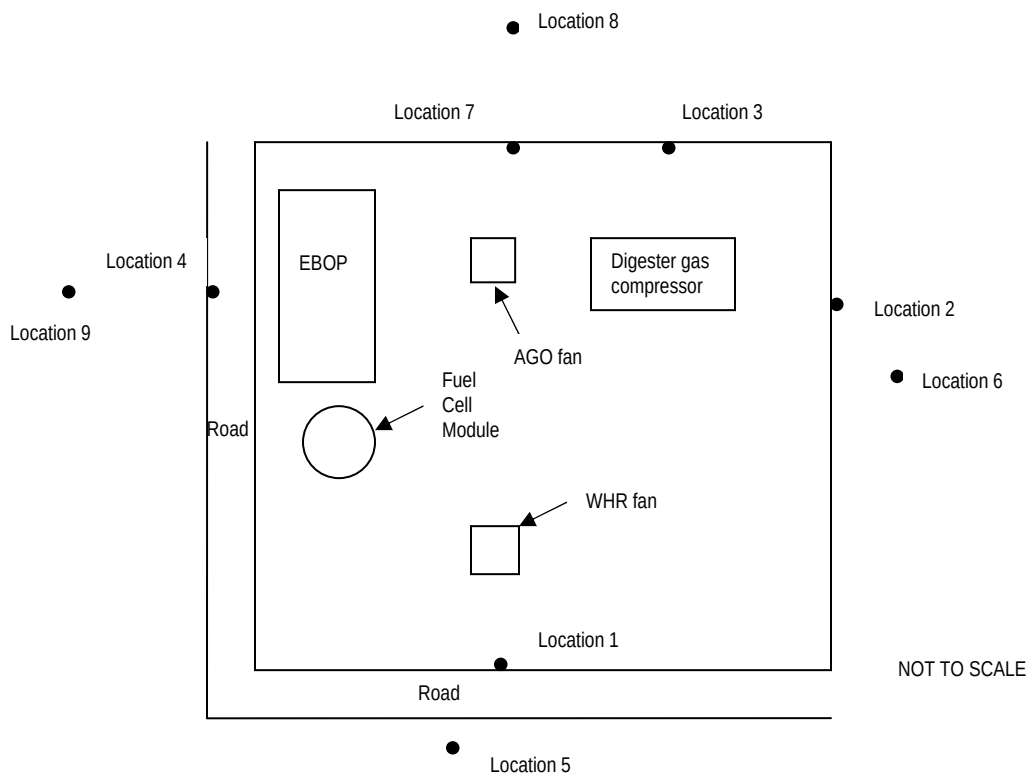
Performance goal achieved: *Yes.*

This performance goal was achieved in a majority of sampling locations when the waste heat recovery fan was off and was exceeded when the fan was on.

Methods

Noise measurements were collected on June 14, 2005. The measurements were taken in the vicinity of the fuel cell at distances of 10 and 100 feet from equipment while the plant was operating on digester gas. Measurements were taken at each location with the waste heat recovery fan (WHR fan) on and off. Figure 5-2 shows measurement locations.

Figure 5-2. Noise Measurement Locations



Noise Levels

Table 5-6 shows the measured noise levels. The noise limits were exceeded at Location 2 (near the digester gas compressor) and Locations 7 and 8 (near the anode gas oxidizer fan) with the WHR fan off, and at all locations except Location 4 (near the electrical balance of plant) with the fan on.

Table 5-6. Measured Noise Levels (power plant operating on digester gas)

Location	Distance to Noise Source (feet)[a]	Noise Level		Dominant Source with WHR Fan On	Dominant Source with WHR Fan Off
		WHR Fan On (dBA)	WHR Fan Off (dBA)		
1	10	76.5	61.5	WHR fan	Remaining sources
2	10	73.5	70.8	Digester gas compressor	Digester gas compressor
3	10	74.5	69.9	Digester gas compressor	Digester gas compressor
4	10	63.5	60.6	Electrical balance of plant	Electrical balance of plant
5	100	62.5	57.8	WHR fan	Remaining sources
6	100	66.4	59.6	Digester gas compressor	Digester gas compressor
7	10	76.9	74.4	Anode gas oxidizer (AGO) fan	Anode gas oxidizer fan
8	100	60.5	60.4	Anode gas oxidizer fan, digester gas compressor	Anode gas oxidizer fan, digester gas compressor
9	100	60.9	58.5	Electrical balance of plant	Electrical balance of plant

[a] The metric sets a 70 dBA noise limit for 10 feet from the source and a 60 dBA noise limit for 100 feet from the source.

Performance Goal 4—Produce energy at a minimal cost

Metric: *Minimal cost is defined, in terms of full time equivalents (FTEs) as (i) 0.2 FTE for operations, (ii) 0.2 FTE for maintenance, and (iii) 0.1 FTE for miscellaneous expenditures. In addition, the cost to produce 1 kWh of power is less than $0.10 (assuming a premium is paid for green power since energy from local utility is approximately $0.05).*

Performance goal achieved: *No.*

Metrics in this performance goal were not met. Although the cost of producing energy while operating on digester gas was lower than the metric, the power plant operated on digester gas for only 2,401 hours (100 days). This operating period may be too short to yield a representative operating cost with digester gas as a fuel source. The cost of producing energy while operating on natural gas was above the metric. The plant operated on natural gas for a total of 9,013 hours (375 days).

Labor Costs

Labor costs incurred by King County during the demonstration period were categorized as oversight, operations support, and maintenance support (preventive and corrective). They include costs associated with both steady-state power plant operation and process equipment modifications.

King County staff assigned to project oversight included a project manager, project engineer, senior day shift operator, and plant process analyst. Oversight consisted of coordination between treatment plant staff, FCE field staff, and engineering consultant staff. Recurring tasks ranged from collecting process information for confirmation of performance goals to coordinating the consultant's reporting activities.

King County staff assigned to operations support included treatment plant shift crew operators, a senior day shift operator, and a plant process analyst. Operations support included daily visual inspection of power plant systems, response to process alarms, and training on operation of the fuel cell power plant. (FCE field service staff provided support in troubleshooting power plant alarms.)

King County staff assigned to preventive maintenance included mechanical, instrumentation, and electrical personnel from the treatment plant maintenance staff. Maintenance was conducted in accordance with FCE maintenance manuals. Several subsystems of the power plant were serviced by outside vendors.

King County staff assigned to corrective maintenance included mechanical, instrumentation, and electrical personnel from the treatment plant maintenance staff. Corrective maintenance of power plant equipment was performed either under the direction of FCE staff or with guidance from equipment manufacturers.

Table 5-7 shows King County's labor expenditures for the power plant two-year demonstration. The data were collected from King County project control reports.

Table 5-7. King County Labor Hours

	Year 1		Year 2	
Category	**Hours**	**FTEs**	**Hours**	**FTEs**
Project oversight	2,218	1.3	743	0.4
Operations support	2,233	1.3	1,613	0.9
Maintenance support	515	0.3	482	0.3
Total	**4,966**	**2.9**	**2,838**	**1.6**

FTE = 1,720 hours.

Materials and Consumables

Table 5-8 shows materials costs, such as parts, associated for each labor category and consumables costs, such as gas scrubbing media, water treatment system media, and nitrogen.

Table 5-8. Materials and Consumables Costs

	Cost ($)	
Category	**Year 1**	**Year 2**
Project oversight materials	373,940	196,540
Operations support materials	2,125	1,500
Maintenance support materials	1,015	12,520
Consumables	43,875	31,505
Total	**420,955**	**242,065**

Cost to Produce Energy

Production costs were calculated for each of the available fuel sources—natural gas (either local utility or treatment plant scrubbed gas) and raw digester gas. Operation and maintenance labor costs, materials costs, consumables, and amount of generated power were used to calculate an overall energy production cost for the entire demonstration period. The cost of energy also included the site-specific fuel value associated with South Treatment Plant operation. The digester gas at the plant has a defined value because it can be scrubbed and sold to a local utility. Natural gas was priced at $1.30 per therm; digester gas was priced at $0.60 per therm. Capital costs for power plant equipment were not included in the calculation.

The following formula was used to calculate the cost of energy:

Cost of energy ($/kWh) = (fuel gas cost + labor cost + materials cost)/energy generated

The labor rate for operation and maintenance was $45 per hour. Project costs associated with demonstration aspects of the project and FCE field staff support were not included in the calculation. Examples of demonstration-specific expenditures include analytical support defined in the testing plan and project oversight. The calculated power plant energy production costs and labor equivalents are shown in Table 5-9.

Table 5-9. Energy Production Costs and King County Labor Full-Time Equivalents

	Year 1		Year 2	
Performance Metric	**Natural Gas**	**Digester Gas**	**Natural Gas**	**Digester Gas**
Cost of Energy ($/kWh)	0.15	0.09	0.16	NA[a]
Operations Labor (FTE)	1.3		0.9	
Maintenance Labor (FTE)	0.3		0.3	

[a] Power plant did not operate on digester gas in second year.

Performance Goal 5— Produce minimal air emissions while operating on either natural gas or digester gas

Metric: *Air emissions limits include (i) carbon monoxide (CO) less than 10 ppmv, (ii) nitrous oxides (NOx) less than 2 ppmv, and (iii) non-methane hydrocarbons (NMHC) less than 1 ppmv.*

Performance goal achieved: *No.*

Stack emissions testing was conducted during fuel cell operation on both natural gas and digester gas.

The results from air emission sampling in July 2004 during operation on natural gas (scrubbed digester gas) were below the metric limits for all three constituents—nitrogen oxides (NOx), carbon monoxide (CO), and non-methane hydrocarbons (NMHC). The fuel cell power output during the sampling event was less than the 1 MW nominal. The results from air emission sampling in June 2005 during operation on digester gas show that NOx was below the metric limit and that CO and NMHC exceeded the limits.

These results are described in the following sections.

Natural Gas (Scrubbed Digester Gas)

California Air Resources Board (CARB) emission testing occurred on July 27 and July 28, 2004 while the fuel cell was operating on natural gas. The CARB 07 limits were set at 0.07 lb NOx/MWh, 0.1 lb CO/MWh, and 0.02 lb NMHC/MWh.

Exhaust gas was measured during three 1-hour operating periods at 50, 75, and 100 percent power. The measured values were averaged for each power condition and reported on a dry basis (Table 5-10). Overall emission results were calculated using the following weighting of measured values: (0.2 x 50% power level) + (0.5 x 75% power level) + (0.3 x 100% power level). The weighted results were 0.017 lb NOx/MWh, 0.094 lb CO/MWh, and 0.003 lb NMHC/MWh. All three pollutants were below the CARB 07 limits.

Table 5-10. Fuel Cell Power Plant Stack Emission Results While Operating on Natural Gas (Scrubbed Digester Gas) – July 2004

Power level	50%	75%	100%	Overall[a]
Net AC (kW)	511	757	1,005	
Stack temperature (^{o}F)	692	627	676	
NOx (ppbv)	1,643	216	224	
NOx - as NO_2 (lb/MWh)	0.064	0.0059	0.0057	0.017
CO (ppmv)	6.7	4.5	5.3	
CO (lb/MWh)	0.126	0.075	0.104	0.094
NMHC (ppmv)	0.6	0.2	0.5	
NMHC – as C (lb/MWh)	0.0048	0.0014	0.0038	0.003

[a] Overall results were calculated as follows: (0.2 x 50% power level) + (0.5 x 75% power level) + (0.3 x 100% power level).

Digester Gas

Power plant stack emissions testing was conducted on June 8, 2005, during operation with digester gas. Three samples were collected while the fuel cell operated at 100 percent power. The NOx, CO, and NMHC results (averaged) were 0.20 ppmv, 13 ppmv, and 42 ppmv, respectively. The results exceeded the metric limits for both CO and NMHC. The elevated levels were caused by gasket leakage inside the fuel cell stack.

Stack emissions testing was not repeated after the fuel cell module was replaced in July 2005.

Performance Goal 6—Produce wastewater with no adverse impacts on treatment plant

Metric: *Water treatment system brine, compressor cooling water, and scrubber condensate characteristics are less than typical industrial pretreatment pollutant levels.*

Performance goal achieved: *Yes.*

The results of the limited process water sampling that was conducted show that all of the measured constituents were below concentrations typically found in raw wastewater entering the treatment plant, suggesting that fuel cell process water discharged to the treatment plant posed no greater impact than raw wastewater.

Water Treatment System

The water treatment system flow that was routed to the process drain was sampled on May 13, 2005. The sample was analyzed for metals and hydrocarbons. Concentrations were less than method detection limits for all metal species (< 1 µg/L) and hydrocarbon ranges (< 1 mg/L).

Cooling Water

Cooling water for the digester gas compressor water jacket that was routed to a process drain was sampled May 12, 2005. The cooling water source was filtered, disinfected secondary effluent from the treatment plant. The sample was analyzed for metals and hydrocarbons. The results were less than method detection limits for most metal species (< 1 µg/L) and hydrocarbon ranges (< 1 mg/L). The metals with the highest, measured concentrations were copper and zinc at 20 µg/L and 16 µg/L, respectively.

Media Scrubber Condensate

The condensate from the digester gas polishing media was routed to a process drain. The condensate was sampled on May 13, 2005. The sample was analyzed for total sulfide. The concentration was less than the method detection limit of 0.2 mg/L.

Performance Goal 7—Operate the power plant on a continuous basis

Metric: *Limit down-time for maintenance and troubleshooting to 20 hours/week and maintain fuel cell in hot standby condition during these periods – record frequency and duration when fuel cell is out-of-service. During operation, run the fuel cell at full power 85% of the time for the 2-year demonstration period and provide greater than 80% availability. Availability is defined as "the percentage of time the power plant is producing power when the plant has the opportunity to perform."*

Performance goal achieved: *Yes.*

Over the two-year demonstration period (17,520 hours), the power plant produced power at greater than 800 kW for a total of 9,837 hours. The power plant was secured for an extended period on two occasions:

- From mid-September through mid-December 2004—a total downtime of 1,344 hours, for a planned treatment plant electrical outage.
- From late June 2005 through early December 2005—a total downtime of 3,960 hours, initially for installation of a new module because of a stack replacement and then for a planned treatment plant mechanical and electrical outage.

The difference between the sum of these two extended outages (5,304 hours) and the 17,520 hours in the demonstration period is 12,216 hours, which represents the amount

of time the power plant had the opportunity to perform. The plant produced power for a total of 11,414 hours. The resulting availability was 93 percent, and the performance goal was achieved.

During power plant operation, the fuel cell performed at full power (greater than 800 kW) 89 percent of the time. The exceptions were limited to planned power ramping, transitioning between fuel sources, or hardware troubleshooting.

Performance Goal 8—Operate the fuel cell efficiently

Metric: *Maintain electrical efficiency of 45.0% on both natural gas and digester gas fuel sources.*

Performance goal achieved: *No.*

The fuel cell operated with an electrical efficiency of 43 (± 1) percent when operating on both natural gas and digester gas. The efficiency calculations and quarterly performances are reported under Performance Goal 2.

Performance Goal 9—Monitor and control the power plant remotely

Metric: *Monitor and control the fuel cell through supervisory control and data acquisition (SCADA) system from operations building at FuelCell Energy's office in Danbury, Connecticut.*

Performance goal achieved: *Yes.*

Remote monitoring and control capability was consistently demonstrated over the two-year demonstration period. Staff in FCE's Connecticut office performed control logic modifications, troubleshot power plant processes, and extracted all power plant process data for data reduction prior to distribution to the project team.

Performance Goal 10—Remove hydrogen sulfide effectively from digester gas

Metric: *Remove hydrogen sulfide to less than 10 ppmv in inlet gas to fuel cell.*

Performance goal achieved: *Yes.*

Digester Gas

Analysis of digester gas samples indicated that the installed gas treatment system was operating well. All six grab samples showed that the hydrogen sulfide concentration in the third stage of the gas treatment system (the outlet of Polisher B) was less than 0.1 ppmv. Using these results and assuming that the hydrogen sulfide concentration in the digester gas entering the system ranged from 40 to 200 ppmv, the removal efficiency of the digester gas treatment system was in excess of 90 percent.

A total of approximately 30 million cubic feet of gas flowed through the digester gas treatment system over the two-year demonstration period. Digester gas sampling was conducted to verify performance of the digester gas treatment system. Six grab samples

were collected from February 2004 through June 2005 from the outlet for each stage of the process: the SulfaTreat® media vessel, first-stage Polisher A, and second-stage Polisher B. Table 5-11 shows the sampling results. The hydrogen sulfide concentration in the outlet gas from Polishers A and B ranged from less than 0.002 to 0.011 ppmv. The hydrogen sulfide concentration in the gas from the SulfaTreat®outlet ranged from less than 0.010 to 11 ppmv of hydrogen sulfide. The SulfaTreat® media were removed and replaced after the higher hydrogen sulfide concentrations were detected in March 2005. As of this date, the media had been exposed to 24.6 million cubic feet of gas.

Table 5-11. Hydrogen Sulfide Sampling Results for Digester Gas Treatment System

Test Date	SulfaTreat® Outlet (ppmv)	Polisher A Outlet (ppmv)	Polisher B Outlet (ppmv)
Feb. 12, 2004[a]	0.076	0.011	0.004
Feb. 14, 2005[b]	<0.010	<0.010	<0.010
March 18, 2005[a]	11	0.006	<0.002
March 21, 2005[a]	0.600	0.003	0.002
May 15, 2005[c]	<0.100	<0.100	<0.100
June 7, 2005[c]	<0.100	<0.100	<0.100

Notes:
(1) The SulfaTreat® media were replaced in late March 2005 because of the high hydrogen sulfide levels measured on March 18 and 21.
(2) Values shown are a function of equipment detection limits
[a] Measured using a Jerome meter.
[b] Lab analysis.
[c] Measured using a colorimetric tube.

Natural Gas

Natural gas sampling was conducted to verify performance of the fuel cell power plant cold gas desulfurizer media beds. Fourteen grab samples were collected on May 19, 2004, April 28, 2005, and June, 21, 2005. Samples were collected from the desulfurizer system inlet, Outlet A, and Outlet B. The samples were analyzed for volatile sulfur compounds.

Eleven of the fourteen grab samples were analyzed in the field using either a Jerome meter or colorimetric tubes. The hydrogen sulfide results from Outlet B were all less than the 0.100 ppmv instrument detection limit. Three of the fourteen grab samples were shipped to a laboratory for testing. Laboratory gas chromatography methods provided an instrument detection limit ranging from 0.005 to 0.010 ppmv. With the reduced detection limits, several volatile sulfur compounds were measured in the gas samples. The results from Outlet B samples are included in Table 5-12.

A total of approximately 71.5 million cubic feet of gas flowed through the gas desulfurizer beds over the two-year demonstration period. The type of desulfurizer media was changed following the May 2004 sampling event. In addition, the upstream carbonyl sulfide (COS) scrubber was added to the gas treatment system in May 2005.

Table 5-12. Results of Gas Chromatography Analysis for Sulfur Compounds in Natural Gas Samples from Desulfurizer Outlet B

Volatile Sulfur Compounds (ppbv)	May 19, 2004	April 28, 2005	June 21, 2006
Hydrogen sulfide	<0.010	<0.010	<0.010
Carbonyl sulfide	0.150	<0.005	<0.005
Carbon disulfide	0.016	<0.005	<0.005
Dimethyl sulfide	<0.010	0.004	<0.005
Ethyl methyl sulfide	<0.010	0.445	<0.005
Unknown compounds	0.090	NR	NR

NR = not reported.

Performance Goal 11—Dispose of power plant solid waste at a reasonable cost

Metric: *The reasonable costs are defined in terms of replacement intervals. The intervals are as follows (i) 0.6 years for SulfaTreat scrubber media, (ii) 0.3 years for scrubber carbon media – both natural gas and digester gas systems, (iii) 3 years for fuel cell stack, (iv) 5 years for preconverter, oxidizer, and deoxidizer catalysts. In addition, evaluate the recovery of precious metals from deactivate catalysts and confirm fuel cell stacks are not negatively affected by digester gas fuel source.*

Performance goal achieved: *No.*

During the two-year demonstration period, the SulfaTreat® media were replaced in the digester gas scrubbing system. The removed media were subjected to a series of tests to confirm their classification as a non-hazardous material for disposal. Samples were collected from both the media and leachate from the media and were analyzed on March 29, 2005. Analytical parameters included total solids, metals, and organics. Test results confirmed the classification, and the media were disposed of onsite at the treatment plant.

The metals results from the media testing included the following concentrations (in mg/kg) listed from highest to lowest: copper (4,235), chromium (100), nickel (52), barium (53), zinc (41), arsenic (39), and lead (20). Media were measured at 90 percent total solids. Organics in the media testing were generally below method detection limits (typically 100 to 2,700 µg/kg) except for acetone (1,075 µg/kg).

The list of organics tested in the media leachate included trichloroethylene, dichloroethylene, dichloroethane, methyl ethyl ketone (MEK), benzene, carbon tetrachloride, chlorobenzene, chloroform, tetrachloroethylene, and vinyl chloride. All results from the leachate testing were below a method detection limit of 1 µg/L except for MEK (11 µg/L).

Based on a digester gas flow of 225 cubic feet per minute and totalized flow through the media of 24.6 million cubic feet of gas, the SulfaTreat® media life is estimated at 76 days (0.2 year). This media replacement interval is considerably shorter than the metric value of 0.6 year. As the first stage in the three-stage digester gas treatment system, the SulfaTreat® scrubber media were performing the majority of the hydrogen sulfide removal, as shown earlier in Table 5-11. This configuration may extend the replacement interval of the second- and third-stage carbon media scrubbers (polishers) but may not be the most cost-effective approach.

The other replacement intervals in the metric could not be evaluated because there was not enough flow of gas through the media during the two-year demonstration period.

Performance Goal 12—Recover waste heat from the power plant

Metric: *Recover 1.4 MMBH of heat from external waste heat recovery system operating with stack exhaust temperature of 650°F.*

Performance goal achieved: *No.*

The power plant was equipped with an external waste heat recovery unit (WHRU) installed on the exhaust stack. The unit operated only when the fuel cell was generating power and the exhaust stack temperature was above 650°F. Temperature readings across the WHRU low-temperature loop heat exchanger were manually recorded. The temperature and corresponding flow were used to calculate the recovered heat in million BTU/hour (MBTU/hr).

Table 5-13 summarizes WHRU performance. Following commissioning in January 2005, the WHRU recovered 1.3 million BTU/hour when the power plant was operating at full power. The efficiency of the WHRU was not optimized while it operated; the unit served only to demonstrate the ability to recover heat from the power plant.

Table 5-13. Power Plant Waste Heat Recovery Unit Performance

		2005				2006	
Parameter	**Unit**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**
Mean heat recovery	MBTU/hr	-	1.31	-	0.96	1.00	1.22
Data collection	No. of days	-	18	-	2	6	11

Performance Goal 13—Demonstrate output turndown on power plant (operation at less than 100 percent capacity)

Metric: *Confirm stable operation of fuel cell at power levels ranging from 25% to 100% and with either digester gas or natural gas fuel source.*

Performance goal achieved: *Yes.*

The power plant was operated at several power levels during emissions testing conducted in July 2004. With the plant operating on a natural gas fuel source, the power was varied from 25 to 100 percent in 1-hour increments. No extended operation at reduced power level was documented during the two-year demonstration period.

Extended operation of the fuel cell power plant at reduced power level with digester gas fuel source was not performed.

Performance Goal 14—Demonstrate power output design ramp rate

Metric: *Confirm power ramp of 0.5 kW per minute from cold start.*

Performance goal achieved: *Yes.*

During the two-year demonstration period, various power plant alarm conditions prompted transition from power generation to a hot standby condition. The fuel cell's subsequent return to power generation occurred with a power ramp. This power ramp consistently exceeded 1.0-kW per minute.

A power plant cold start required an external startup heater to slowly heat the fuel cell cathodes. The heating sequence proceeded through four stages and was based on the temperature of the oxidant gas entering (cathode inlet) or leaving (cathode outlet) the stack. It took up to three days to bring the stack assembly to operating temperatures while minimizing the risk of thermal imbalances. During the time it took to bring the plant up to operating temperature, the plant was not generating power and therefore the metric did not apply.

Performance Goal 15—Meet the design service life of the fuel cell stacks

Metric: *Fuel cell stack design service life of 10,000 hours (1.15 years).*

Performance goal achieved: *No.*

Neither of the two fuel cell modules used during the demonstration project achieved the stack design service life of 10,000 hours.

The first fuel cell module operated for 7,860 hours from the start of the two-year demonstration period (June 2004) until it was replaced in July 2005.[7] A detailed inspection of the removed module stacks by FCE staff indicated that the cause was failed manifold gaskets, resulting from pressure and temperature transients generated by the high frequency of power trips and operational upsets.

The replacement module operated through the end of the two-year demonstration period (June 2006). The power plant continued to operate until it experienced an unusual electrical event in July 2006. The event triggered a plant shutdown because of a

[7] The number of hours of operation given for this performance goal are the hours that the fuel cell module was at operating temperature, which will be greater than the number of hours that the module was generating energy.

fuel stack current deviation. The replacement module operated for 5,470 hours. Subsequent inspections conducted by FCE staff identified the cause as a structural failure of internal components of the stack assembly arising from poor weld quality.

Performance Goal 16—Confirm ability to restart from a trip condition

Metric: *Trip recovery to back online in approximately 10 hours.*

Performance goal achieved: *Yes.*

The recovery time from a power plant trip caused by an alarm condition was highly variable and a function of the cause of the condition, but all recovery times were above the metric of 10 hours. Control system alarm responses ranged from plant hot standby (short recovery period) to plant complete shutdown (long recovery period). The recovery period from a hot standby trip was typically greater than 10 hours but less than 24 hours. The recovery period from a complete shutdown was from one to three days.

FCE staff performed several planned trip conditions early in the demonstration period to confirm the ability to restart. Under these controlled conditions, shorter restart times than the metric were realized.

Several examples of power plant restart conditions are included in Appendix E.

Performance Goal 17—Confirm ability to quickly start the power plant

Metric: *Quick start defined as 10 hours from standby to rated output with the assumption that power plant start was initiated from hot standby.*

Performance goal achieved: *Yes.*

This metric was consistently met while operating on natural gas. The average time required to achieve rated output from hot standby was 9 hours.

A total of fifteen power plant starts on natural gas were evaluated over the two-year operating period. In the second year of demonstration testing, the power plant start time was consistently at 8 hours.

The five power plant starts on digester gas required an average of 14 hours to achieve rated output from hot standby. The power plant operating time on digester gas was a contributing factor in limiting the optimization of ramping from hot standby to full power.

SECTION 6

Operational Challenges and Design Improvements

This section highlights demonstration period experiences and operational challenges. It is organized by topic and concludes with a summary of power plant design improvements either implemented during the testing or planned for future plant configurations.

Integration with Wastewater Treatment Plant Utilities

The operation of the power plant was affected both by where the digester gas was tapped in the wastewater treatment plant and by the availability of scrubbed digester gas. In addition, treatment plant utility connections to the fuel cell power plant were disrupted by treatment plant construction activities that occurred after commissioning of the fuel cell power plant.

The following sections describe these challenges.

Digester Gas Quality

Digester gas moisture and methane content adversely affected the power plant operation:

- Digester gas was collected from a 30-inch gas header located at the treatment plant waste gas burner facility and routed approximately 560 feet to the fuel cell site through 12-inch-diameter buried piping. The piping was designed to slope 0.5 foot to allow gravity draining of water condensed from the digester gas. Accumulated moisture in the digester gas supply piping led to multiple gas compressor shutdowns. A large moisture trap was installed on the upstream side of the digester gas compressor skid. Unfortunately, the trap was not completed until the end of the two-year demonstration period.
- When scrubbed digester gas did not meet natural gas utility standards and was diverted to the waste gas burner facility, the methane content of the digester gas rapidly increased. The observed changes in fuel composition exceeded acceptable limits for reliable fuel cell operation. The power plant control logic was modified in fourth quarter 2004 to automatically switch from digester gas to natural gas when scrubbed digester gas was being diverted to the burners. This new logic proved to be invaluable for the remainder of the demonstration period.

Scrubbed Digester Gas Availability

Because of interruptions of the treatment plant digester gas scrubbing system, primarily for maintenance, the power plant fuel supply system was modified in the first year of operation to provide utility natural gas as a backup. Modifications were made to the

piping configuration, and gas scrubbing media were added to remove the carbonyl sulfide present in the natural gas.

Utility Isolation from Construction Activity

The fuel cell power plant did not have a dedicated electrical supply. The power plant was secured for three weeks in third quarter 2004 and three months in third and fourth quarters 2005 because of scheduled power outages associated with treatment plant construction activities.

Power Plant Module Malfunctions

The power plant module was replaced three times during the project:

- During power plant commissioning in early 2004, moisture was discovered in the stack module. Module inspection after delivery found no compromise of module assembly. It was assumed that water had entered the module sometime between delivery and plant commissioning. The module was replaced with a second module shipped from the FCE manufacturing facility.
- In June 2005, alarm conditions for fuel cell temperature and voltage deviations indicated that the fuel imbalance condition suspected earlier had worsened. Steps were taken immediately to cool down the plant to prevent further damage to the fuel cell stack. The original fuel cell module that was returned to FCE because of moisture was reinstalled on July 25. Detailed internal inspection of the replaced module and manifold showed breaches in the gaskets caused by the high frequency of trips and operational upsets.
- On July 29, 2006, the power plant experienced a high stack-to-stack current deviation followed by an emergency shutdown triggered by Stack D voltage. FCE performed an extensive root cause analysis. Additional inspections found that the cathode-out manifold on Stack D was damaged. The internal structure of the manifold had failed, touching the stack. It appeared that when the cathode-out manifold supports touched the live cells, an internal current loop was created that dropped the voltage of Stack D. The other three stacks tried to pick up the current being drawn by the inverter. The plant finally tripped on a voltage signal and could not be recovered. The problem posed no danger to personnel. The short occurred inside the module via a manifold isolated from ground. The entire exterior of the module was hard grounded at the site.

The module will be returned to FCE for a detailed visual inspection to determine the extent of internal damage. The manifold design is used on both the megawatt and sub-megawatt designs. FCE has seen only one other instance of this type of failure throughout the fleet, which was traced to a vendor quality problem. FCE has implemented quality plans with the vendor and made design changes to prevent similar failures.

Fuel Gas Treatment Systems

The following operation and maintenance challenges in the fuel gas treatment systems were encountered during the demonstration period:

- The power plant's scrubbed digester gas treatment system was modified to accommodate utility natural gas as a backup to scrubbed digester gas. Because the utility natural gas contained high levels of carbonyl sulfide (COS), which could damage the fuel cell, special copper and aluminum oxide media were temporarily installed in the two existing cold gas desulfurizer vessels and then a new COS removal vessel was installed in second quarter 2005 to treat both scrubbed digester gas and utility natural gas upstream and in series with the existing gas desulfurizers.
- The digester gas compressor cooling water was originally plumbed with potable water and operated at a flow of 10 gpm. After the cooling water was switched from potable water to treatment plant reclaimed water to reduce operating costs, biofouling occurred in the water jacket. To minimize the risk of fouling, an automated strainer was installed on the reclaimed water supply.
- Space constraints in the gas compressor skid proved challenging for maintenance activities.
- There was no redundant SulfaTreat® tower in the first-stage treatment of digester gas. The fuel source had to be switched during media replacement.
- The gas scrubber media required testing prior to disposal of spent material. Treatment plant staff were concerned that failed media bioassays would change the plant's hazardous waster generator status and lead to increased labor and disposal costs.

Ancillary Systems

Configuration of ancillary systems created some maintenance challenges, as described below.

Nitrogen Purge System

When the power plant was placed in shutdown mode, a nitrogen gas system purged the anode gas treatment equipment and the fuel cell anodes to avoid nickel carbonyl formation and condensation. Another (slow) nitrogen purge system was used to protect the fuel cell module from air intrusion after a plant shutdown. Frequent replacement of the nitrogen bottles required two operators and a forklift. The process was both time consuming and a safety concern. A design modification was approved to install an external connection for the nitrogen bottles. The demonstration period expired before the design could be implemented.

Long-term shutdown of the power plant required installation and permitting of a liquid nitrogen system with vaporizer for purging of fuel cell stack module.

Water Treatment System

Components of the water treatment system were housed in a heated enclosure. Space constraints in the enclosure provided challenges for both process water sampling and

maintenance activities. Maintenance was conducted by an outside vendor under service contract.

Instrument Air System

All equipment in the instrument air system was housed outdoors next to the anode gas oxidizer. The following challenges were encountered in operating and maintaining the instrument air system:

- The programmable logic controllers for the air compressors were adversely affected by the outdoor environment. Two controllers were replaced because of moisture damage.
- The air dryers were difficult to access for maintenance.
- The air compressors required considerable maintenance. Maintenance was done by King County staff and an outside vendor.

Power Plant Distributed Control System

The distributed control system (DCS) provided data acquisition, monitoring, and control functions for the power plant. The DCS used a human-machine interface to monitor the operation and performance of the plant, either locally or remotely.

Remote access to the power plant was available either via phone modem using PC Anywhere or via the Web using a standard Internet browser. The modem connection provided remote monitoring and control capabilities. The remote control and monitoring capabilities were limited to FCE staff. The Web-based access provided to treatment plant staff included partial monitoring capability only.

A process screen located in the wastewater treatment plant required transfer of information from the power plant. The transfer of analog and discrete process signals from the power plant DCS to the wastewater treatment plant control system proved to be unreliable for a large portion of the demonstration period. As a partial solution, the power plant DCS system was equipped with an alarm modem that alerted treatment plant operations staff via pager in the event of a process alarm.

Power Plant Modifications

Table 6-1 describes features of the demonstration plant design and how these features will be improved in next-generation designs.

Table 6-1. Power Plant Design Improvements Resulting from Demonstration Project

Power Plant Component	Demonstration Plant Design	Next-Generation Design Improvement
AC power distribution	Electrical Balance of Plant power distribution panels have individual power circuits to skids.	Each skid equipped with its own power distribution panel with a single 480-V feed to reduce field installation time
Anode gas oxidizer	Oxidizer is external, gas-fired, and expensive; it increases heat loss and pressure drop.	An internal oxidizer integrated with the fuel cell to reduce cost and improve efficiency
Control system	Central processor restricts plant modification without substantial cost.	Distributed system to facilitate installation and customization
Control system	F60 relay (utility grade protection) has no remote monitoring/operational capabilities.	New CPU card with Ethernet capability to allow remote communication and troubleshooting
DC power distribution	Common DC bus requires isolation diode between four stacks.	Eliminate common DC bus; design each stack with a dedicated inverter to improve reliability
Instrument air system	Air is required for burner pilot and pneumatic valves, which increases parasitic load.	Remove instrument air system; replace with motor actuated valves and spark-igniter pilot to reduce costs and improve operation and reliability
Instrument air system	Compressors and dryers require frequent local operations to swap lead and follow status and balance run time.	A design concept involving control software and equipment modifications will be developed
Maintenance	Some components are expensive to maintain and difficult to access.	Several design improvements to address number of components, access, and cost
Periodic maintenance (PM) requirements	PM frequencies were based on the calendar, with limited references to accumulated operating time of the power plant.	Improve PM schedule to differentiate component checks based on either calendar or operating time
Shipping cost	Large size of skids requires special road permits; high shipping cost.	Reduced skid sizes
Stack module	Four stacks use common gas intake; cannot operate unit if one stack is damaged.	Stacks with individual gas intakes
Superheater	The superheater is external, which increases heat loss, consumes instrument air, and raises costs.	An internal superheater integrated with the fuel cell to reduce cost and improve efficiency
Waste heat recovery	Waste heat recovery boiler is located at grade, adjacent to skids and connected via ductwork. This non-traditional design addressed concerns about backpressure on fuel cell stacks.	Place the boiler directly in the stack to improve heat recovery efficiency
Water treatment system	The water treatment package is complex, consisting of several media types and reverse osmosis membranes, and provides only limited access for maintenance.	Simplified water treatment package with improved accessibility

SECTION 7

Conclusions and Recommendations

The fuel cell power plant completed two years of operation at the King County South Treatment Plant in Renton, Washington. During this period, the plant operated on both natural gas (375 days) and digester gas (100 days). The project accomplished many of the defined performance goals. The results of the project will serve as a valuable resource to any agency considering fuel cell stationary power plants as a means to beneficially use digester gas.

Testing the first digester gas application for a molten carbonate fuel cell gave FuelCell Energy (FCE) and King County many opportunities to learn about what is needed to make such applications work well. Power plant shutdowns and their causes provided an environment for highly accelerated life and stress testing at the total system level that will benefit next generation fuel cell applications, designs, and operations.

Challenges centered on mechanical and fuel quality issues. No issues were identified that would indicate problems with operating the fuel cell's molten carbonate technology on gas produced from digesting waste products, which was of the highest concern and the fundamental purpose of the program. The failure of the fuel cell module that occurred just after completion of the program was related to deficient welds on the stack manifolds and has been addressed in the vendor manufacturing process, quality inspections, and design specifications.

In general, power plant preventive maintenance activities were successfully performed by King County staff after transfer of these responsibilities from FCE field staff during first quarter 2005. County staff completed training and were provided with power plant maintenance documentation. The documentation for the power plant, with the exception of the digester gas treatment system, provided adequate detail. The documentation for the gas treatment system was not completed during the demonstration period.

It was thought at the start of the fuel cell demonstration project that if the technology proved successful, King County would consider continuing its operation. From experience gained during the project, the county decided not to continue operating the current configuration. A stack replacement and additional modifications would be required to integrate the power plant into the operation of the treatment plant. The costs for repair and upgrades, coupled with the fact that FCE has substantially improved its newest power plant designs, make total plant replacement a more viable option.

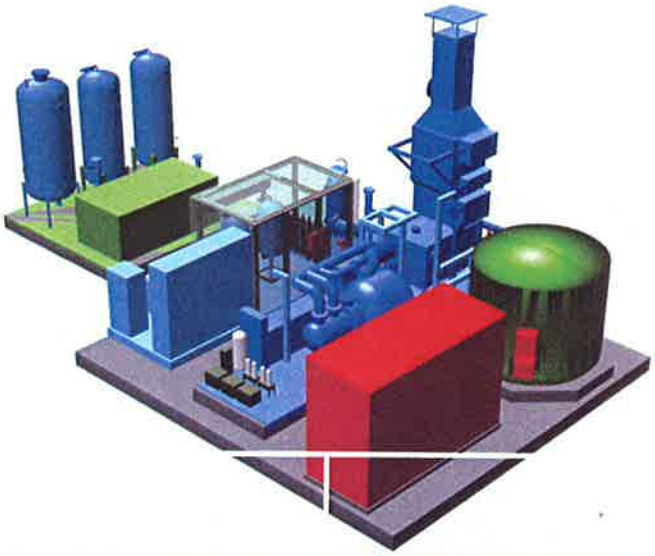
The alternative under consideration is to replace the existing 1-MW power plant with a 300-kW fuel cell. This smaller plant will scale better with available digester gas at the treatment plant. In addition, a smaller fuel cell power plant would be more portable and allow for moves to other King County treatment plants.

For more information on the project, see Appendix F.

Appendix A
Fuel Cell Power Plant Process Design Basis

King County Project

Fuel Cell Power Plant



Project Review
November 2001

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FuelCell Energy

PROCESS DESIGN BASIS

SP-437000-PDB-01

This Process Design Basis has been revised as indicated below. If this is a later revision than now in your possession, please destroy the previous issue.

Rev. No.	Rev. Date	Prepared By Name / Initial	Checked By Name / Initial	Description
A	11/08/00	D. Lamprecht	A. Rao	Preliminary Copy
B	02/01/01	D. Lamprecht	A. Rao	Incorporated Client Comments
0	07/11/01	D. Lamprecht	A. Rao	Approved for Design
1	11/12/01	H. Sandler HS	A. Rao ADR	Update for Plot Configuration Changes & Continued Design Development

PROCESS DESIGN BASIS

This document presents the Process Design Basis for the King County Power Plant (KCPP) Demonstration Project. This plant will be a single module molten carbonate fuel cell power plant facility located at King County's East Section Reclamation Plant in Renton, Washington. It will be fueled with anaerobic digester gas from the local sewage treatment plant, along with the natural gas-like "pipeline quality" scrubbed digester gas produced by the Reclamation Plant for sale to the local natural gas distribution system.

The purpose of this Project is to demonstrate that (1) FuelCell Energy's (FCE) molten carbonate fuel cell technology can be adapted to use anaerobic digester gas from a sewage treatment plant as a fuel gas; and (2) a nominal plant power output target of 1 MW (net ac) can be achieved (using a Fuel Cell Stack Module containing FCE's "Field Trial" generation of fuel cell stacks) on either digester gas or natural gas/scrubbed digester gas. The plant will be adapted from FCE's standard natural gas-fueled single module Direct Fuel Cell (DFC®) power plant design, modified only by the addition of supplemental equipment and controls necessary to pretreat and handle the digester gas. The balance of plant (BOP) components will be sized to enable plant power generation of up to 1.5 MW (net ac) using future technology replacement Fuel Cell Stack Modules containing FCE's "Mature" generation of fuel cell stacks. The plant will be highly modularized, and will feature high efficiency, quiet operation, low emissions, and a small footprint.

The Project's operating characteristics and performance presented in this document reflect fuel cell technology advances that FCE expects to achieve in the near future. The majority of the BOP equipment (including the inverter system) is based on proven and commercially available technology.

1.0 General Design Considerations

The plant design will meet the following requirements:

- Location: Renton, Washington
- Plant Fuel Capability:

  Anode Fuel Gas Makeup: Digester gas or natural gas/scrubbed digester gas (one at a time)

  Oxidizer Burner Fuel: Natural gas/scrubbed digester gas
- Overall Plant Performance Targets with "Field Trial" generation stacks (Nominal Values)

  Rated Output (net ac): 1 MW on natural gas/scrubbed digester gas
  1 MW on digester gas (expected)

Efficiency [LHV]: (At Rated Output / BOL)	48.5% on natural gas/scrubbed digester gas 47% on digester gas
Power Output Turndown:	25% to 100% of Rated Sustainable Output (with stable operation below 25% and when islanding)
Power Output Ramp Rate:	10 percent of Rated Output per minute between 25% and 100% of Rated Output
Time for Hot Start: (Standby to Rated Output)	10 minutes
Time for Cold Start: (Out-of-Service to Rated Output)	<70 hrs (20 hrs with "Mature" generation stacks)

- Electrical Characteristics

Output Voltage:	460 Volt per sewage treatment plant internal grid (IEEE Standard 519)
Power Factor Range:	0.90 Lag to 0.90 Lead at Rated Output
Power Output Phase:	3 Phase, Wye, 4 Wire
Frequency, Hz:	60
DC to AC conversion efficiency:	95% or greater
Black Start Capability:	Not included; connection to grid will be required or stand alone 480 Vac generator provided

- Plant Controls: Designed for unattended operation with local and remote dispatching / control.

- Height: 32 feet (specific to King County Power Plant)

- Plant Constructability Basis: Modular (skidded) design. Truck transportable skids, complete with preinstalled piping, valves, insulation, instrumentation, and electrical wiring. The plant will be configured to minimize number of skids to limit footprint requirements and to limit interconnectivities during installation.

- Plant Design Life Expectancy: 35 years

- Equivalent Availability: 95%

- Fuel Cell Stack Module

  Number Required in Plant: One

Stack Module Design:	"Hot Box" (Internally Insulated Nearly-Cylindrical Vessel), truck transportable modules, each containing four fuel cell stacks
Fuel Cell Type / Configuration:	Carbonate / DFC® (Direct Internal Reforming / Indirect Internal Reforming (DIR / IIR))
Power Output (Maximum): (net ac at inverter terminals)	1.0 MW on natural gas/scrubbed digester gas 1.0 MW on digester gas (expected) (1.5 MW on natural gas/scrubbed digester gas with "Mature" generation stacks)
Des. Service Life Expectancy:	10,000 hours (40,000 hours with "Mature" generation stacks).
Replacement Philosophy:	Replacement Fuel Cell Stack Modules will be available to meet the 35 year design operating life of the plant, and will be designed to fit into the plant without requiring modifications to the balance of plant components.

- Noise: 60 dB(A) or less at 100 feet from the plant boundary (fence).

Fuel Cell Stack Conditioning Requirements

All Fuel Cell Stack Modules will be preconditioned before being installed at the power plant site.

Plant Configuration Requirements

The plant will be a prototype of FCE's commercial, natural gas-fueled single module DFC® Power Plant, and will have a similar configuration. The only difference will be the addition of a Digester Gas Conditioning system to compress the digester gas and remove sulfur and other contaminants.

Plant Control Requirements

The plant will be designed for unattended operation with local and remote dispatching/ control, although personnel will be required onsite to start or restart the plant. The control system will be able to communicate with a remote monitoring station located at FCE's facilities in Danbury, CT for diagnostic purposes.

Control of the plant will be accomplished using a Scaleable Process Control System (SPCS) type DCS. The majority of control and monitoring interfaces to the process will be via "Smart Type Transducers" communicating over Foundation Fieldbus segments, and Modbus Links to PLC controllers with classic I/O providing motor control and mutiplexor interfaces to the non-smart/indication only instruments.

The DCS controllers, power supplies, bus interface modules, I/O racks, data historian/WEB server and an Engineering/Operator Work Station with a laser printer (for maintenance) will be housed inside the Electrical Equipment enclosure located inside the plant Inside Boundary Limit (IBL). The WEB server will interface via a telephone modem for remote communications and a telephone pager for annunciating alarms.

Plant Startup Requirements

Operator attendance will be required during all plant startups (from a cold condition with fuel cell stacks at ambient temperature) and plant restarts (from a warm condition with the fuel cell stacks at elevated temperature). All nitrogen bottles must be replaced prior to starting up or restarting the plant, and the operator must witness light-off of the Oxidizer burner.

In addition, the plant's permanently installed facilities are not equipped to start up the plant from a cold condition. A Startup System skid containing additional equipment must be temporarily installed at the site for initial warming of the Fuel Cell Stack Module. After completion of the initial warming process, an operator must physically disconnect the Startup System skid from the plant, which can then be removed from the site.

Plant Winterization Requirements

The Cold Gas Desulfurizers will be maintained in a heated enclosure at 60°F or above to enhance bed absorption. The Water Treatment System equipment will be maintained in a heated enclosure at 40°F or above to prevent freezing. The Digester Gas Compressor and associated equipment will be maintained in a heated enclosure to prevent freezing and for sound attenuation. All piping, instruments, and equipment that contain water or digester gas and are exposed to the ambient will be heat traced and insulated to protect them from freezing.

Materials Selection Requirements

The metallurgy of piping and equipment will be selected to ensure the purity and freedom from particulates (including pipe slag, rust, etc.) of the anode fuel gas and cathode oxidant gas supplied to the Fuel Cell Stack Module.

Electrical Classification (Preliminary, based on DFC® Process Design Guide)

On-site equipment and controls will be designed for electrical classification per code (e.g. Class 1, Division 2, Groups B & D).

FCE Provided Equipment

FCE will provide the Fuel Cell Stack Module.

Purchaser Provided Process Gases and Utilities

The purchaser is responsible for providing the following gases and utilities at a regulated pressure to a tie-in location adjacent to the plant site: digester gas, "pipeline quality"

scrubbed digester gas, electricity, cooling water, municipal water and sewer connection for process waste water.

Process Safety Considerations

Special process safety considerations are listed below:

- It is assumed that the Fuel Cell Stack Module will be designed to withstand pressure spikes induced by internal deflagrations, through adequate structural design. The balance of plant (BOP) will not include provisions to protect the stack modules from these deflagration induced pressure spikes, but will be capable of withstanding them.

Special process safety hazards include the following:

- Leaks of treated digester gas downstream from the SulfaTreat Vessel and natural gas/scrubbed digester gas downstream from the Cold Gas Desulfurizers will not be detectable by smell. Strategically located combustible gas detectors will be provided to detect methane gas and fuel gas leaks in the Fuel Gas Preparation System and Digester Gas Conditioning System.

- Carbon monoxide, present in significant concentrations in the anode exhaust gas, is highly poisonous. Strategically located combustible gas detectors may be required to detect CO leaks in the anode exhaust gas piping.

Overall plant safety systems for gas monitoring will be designed to meet all applicable codes.

2.0 Site Data

Site and climatic design conditions for the King County Power Plant are listed in Table 1. Access to the site is via secondary roads.

TABLE 1
SITE DATA

CONDITION	DESIGN POINT (1) (DFC® BASIS)	SITE SPECIFIC DATA
Elevation	0 ft. above sea level	130 ft. above sea level
Avg Ambient Temperature, °F	60	
Min Ambient Temperature, °F	-20	15
Max Ambient Temperature, °F	104	100
Avg. Ambient Pressure, in Hg	29.9	29.5
Avg. Relative Humidity, % RH	60	80
Wind Loading @ 33 ft, PSF	30 (2)	
Precipitation, in/hr	2.5	
Annual Precipitation, in		37.2
Peak Rainfall (One Day), in		3.75
Annual Snow Fall, in		10.4
Maximum One Day Snow Fall, in.		21.4
Snow Load, PSF	30 (3)	25
Seismic Zone	4	3
Ambient Dust Loading, Ave/yr	27 $\mu gm/m^3$	
Ambient Gaseous Halide Conc, Ave/yr	20 ppbw	
Ambient Gaseous SOx Conc, Ave/yr	<10 ppb	
Height Limit, ft	25	32
Noise Limits, db(A) @ 100 ft	60	"Normal OSHA Work Place"

Notes:
1) DFC® Basis used for plant performance projections and design of equipment.
2) Wind load is based on a wind speed of < 90 mph and Exposure C. Exposure C is defined as "open terrain with scattered obstructions having height generally < 30 feet" (American Society of Civil Engineers (ASCE), Standard 7-88)
3) Snow load is equivalent to a ground snow load of 40 PSF and a snow exposure factor of 0.7 (Uniform Building Code UBC-97).

3.0 Fuel Basis

The King County Power Plant will be supplied with two fuel gases: (1) Digester gas from the sewage treatment plant, and (2) a natural gas-like "pipeline quality" scrubbed digester gas produced by the Reclamation Plant for sale to the local natural gas distribution system. Either fuel gas (but only one at a time) can be used for anode fuel gas makeup. Scrubbed digester gas must be used in the Oxidizer's burner and its pilot, as these are designed for natural gas fuel.

The digester gas analysis shown in Table 2 is representative of the range of compositions estimated for the sewage treatment plant. The "typical" digester fuel gas listed in Table 2 is the basis for the plant heat and material balances and performance estimates, and is based on the following sources of data and assumptions:

1. The concentration ranges for the major components, such as CH_4, CO_2, O_2 and N_2, and the gas temperature and pressure are obtained from the King County RFQ. Note: Raw data provided by King County shows that the CO_2 concentration in the raw gas coming off each of their digesters has a significantly wider variation than is listed in this RFQ and reflected in Table 2.
2. The moisture content of the gas is calculated assuming the gas is saturated at the reported temperature and pressure.
3. Trace components in the gas, such as aromatics, sulfur compounds and organic compounds, are estimated from the ACC laboratory data attached to a FAX dated 6/2/99 from Katherine B. of King County Dept. of Natural Resources to Carol Nelson of ESRP.
   - The samples analyzed are all assumed to be those of the raw digester gas as supplied to the fuel cell plant boundary limits.
4. The siloxane concentrations in the gas are assumed to be the same as those reported for the Columbia WWTP as provided by CH2M HILL (sample date 2/27/01, Lab ID: 522304 and 05).
5. The gas is assumed to be free of inorganic chlorine compounds.
6. Molecular weight and heating value of the gas are calculated values.

The reference natural gas composition and range/limit data shown in Table 3 are the basis of design for FCE's standard natural gas-fueled DFC® power plant. This reference natural gas is the basis for the plant performance estimates on natural gas.

Table 4 shows a typical analysis of the "pipeline quality" scrubbed digester gas, along with range/limit data. Plant performance with this fuel (for anode gas makeup) is expected to be comparable to that with natural gas.

TABLE 2
KCPP DIGESTER GAS ANALYSIS

	RANGE / LIMITS [1]	TYPICAL
Composition, Digester Gas		
Methane, vol %	57 – 61	60.5
Carbon Dioxide, vol %	36 – 38	37.5
Nitrogen, vol %	0.6 – 1.1	1.0
Oxygen, vol %	0.2 – 1.4	1.0
Ethane, ppmv	34 – 51	40
Propane, ppmv	<2	1
Butanes, ppmv	<1.3	0.7
Pentanes, ppmv	2.9 – 15	7
Hexanes+, ppmv	4.5 – 108	50
Benzene, ppbv	20 – 40	30
Toluene, ppbv	20 – 800	400
Xylenes, ppbv	800 – 900	850
Water, vol %	Saturated	Saturat ed
Molecular Weight	---	26.78
Sulfur Compounds		
H_2S, ppmv	39 – 200	150
CS_2+SO_2, ppbv	<50	25
Mercaptans, ppbv	<50	25
Organic sulfides/disulfides, ppbv	<50	25
Thiophenes, ppbv	<50	25
Chlorine Compounds		
Methyl Chloride, ppbv	<33	16
Cis-1,2-Dichloroethane, ppbv	40 – 64	52
Chlorobenzene, ppbv	26 – 48	37
1,4 Dichlorobenzene, ppbv	<53	26
Siloxanes		
Tetramethylsiloxane, $\mu g/m^3$	--	794
Hexamethyldisiloxane, $\mu g/m^3$	--	794
Octamethyltrisiloxane, $\mu g/m^3$	--	3030
Octamethylcyclotetrasiloxane, $\mu g/m^3$	--	49600
Decamethylcyclopentasiloxane, $\mu g/m^3$	--	59500
Physical Properties		
Heating Value, Range		
- LHV, Btu/scf	--	552
- HHV, Btu/scf	--	613
Pressure, inches water column	4 – 7	5.5
Temperature, °F	50 – 100	80

Notes: 1) During normal operation of the Reclamation Plant. Digester gas composition will be outside these ranges during Reclamation Plant upsets, approaching that of the scrubbed digester gas because off-spec scrubbed digester gas will be dumped to the digester gas header.

TABLE 3
NATURAL GAS ANALYSIS

	RANGE / LIMITS (DFC® BASIS)	REFERENCE NATURAL GAS (DFC® BASIS)
Composition		
Methane, vol %	80 – 100	93.9
Ethane, vol %	0 – 10	1.9
Propane, vol %	0 – 3	0.6
Butanes, vol %	0 – 1.25	0.5
Pentanes+, vol %	0 – 0.5	0.0
Unsaturated Hydrocarbons	None	None
Inert Gases		
Nitrogen, vol %	0 – 3	1.1
Carbon Dioxide, vol %	0 – 3	1.1
Total Inerts, vol %	0 – 5	2.2
Oxygen, vol %	0 – 0.2	0.0
Impurities		
Total Sulfur, ppmv	0 – 12	6
Grains/100 SCF	0 – 0.7	0.36
H_2S, ppmv	0 – 0.8	0
COS, ppmv	0 – 2	0
Odorants, ppmv	0 – 12	6
Halogens (Cl, etc)	None	None
Dust, Gum, Solid Matter	None	None
Water, lb/MMscf	0 - 7	Dry
Physical Properties		
Heating Value, Range		
- LHV, Btu/scf	870 – 1000	933
- HHV, Btu/scf	970 – 1100	1035
Pressure, psig	15 – 50	15
Temperature, °F	40 – 75	60

TABLE 4
KCPP "PIPELINE QUALITY" SCRUBBED DIGESTER GAS

	RANGE / LIMITS	TYPICAL
Composition		
Methane, vol %	97.6 – 99.1	98.6
Nitrogen, vol %	0.5 – 0.8	0.7
Carbon Dioxide, vol %	0.2 – 1.7	0.7
Oxygen, vol %	0.0	0.0
Impurities		
Sulfur, ppmv	--	6
Halogens (Cl, etc)	--	None
Dust, Gum, Solid Matter	--	None
Water, lb/MMscf	--	Dry
Physical Properties		
Heating Value, Range		
- LHV, Btu/scf	890 – 903	897
- HHV, Btu/scf	988 – 1003	996
Pressure, psig	--	250
Temperature, °F	--	80

4.0 Water Basis

Municipal potable water will be supplied to the King County Power Plant to meet its process water requirements. The KCPP water listed in Table 5 is representative of the municipal water supply at the King County sewage treatment plant site, and is the basis for the plant's water treatment and makeup requirements. The reference water composition and range/limit data for FCE's standard natural gas-fueled DFC® power plant is also shown in Table 5.

TABLE 5
WATER ANALYSIS

	RANGE / LIMITS (DFC® BASIS)	REFERENCE WATER (DFC® BASIS)	KCPP WATER RANGE / LIMITS
Quality			
Calcium (Ca), mg/l as $CaCO_3$	0 – 120	44	34 – 54
Magnesium (Mg), mg/l as $CaCO_3$	0 – 30	16	4 – 46
Sodium (Na), mg/l	N/A	16	11 – 17
Bicarbonate (HCO_3), mg/l as $CaCO_3$	0 – 90	50	
Chloride (Cl), mg/l	0 – 50	17	ND – 7
Sulfate (SO_4), mg/l	0 – 90	20	ND – 16
S Cations, mg/l as $CaCO_3$			49 – 117
S Anions, mg/l as $CaCO_3$			50 – 123
Alkalinity, mg/l as $CaCO_3$			50 – 100
Nitrate, mg/l as $CaCO_3$			0.4 – 2.9
Total Dissolved Solids, mg/l	0 – 350	135	53 – 145
Total Hardness as $CaCO_3$, mg/l	0 – 150	60	38 – 100
Silica (SiO_2), mg/l	0 – 10	3	26 – 57
Iron (Fe), mg/l	0 - 0.1	0.03	0.06 – 0.17
Copper (Cu), mg/l	0 - 0.05	0.01	0.41 max.
Manganese (Mn), mg/l			0.07 – 0.086
Zinc (Zn), mg/l			0.01 max.
Barium (Ba), mg/l			0.004 max.
Total Organic Carbon (TOC), mg/l			1 – 2.2
Chlorine, mg/l			0.01 max.
Silt Density Index	0 – 5	2	
Color, Standard Units			0 – 5
Turbidity (NTU)			0.05 – 0.5
Suspended Solids (SS), mg/l			0.04 – 0.24
Specific Conductance, micromho/cm	0 – 580	205	81 – 230
pH	7 – 8.5	7.6	7.2-7.5
Conditions			
Temperature, °F	40 – 90	59	
Pressure, psig	50 – 65	60	

Notes: ND - Non-detectable; NTU - Nepthelmeter turbidity unit.

5.0 Plant Interfaces

The process gases, utility services, and control interfaces listed in Table 6 will be required for the King County Power Plant. The plant buyer is responsible for line sizing, pressure relief, and pressure regulation up to the plant interface location.

TABLE 6
PLANT INTERFACES

PLANT INTERFACE REQUIREMENTS
Process Gases Digester Gas (raw) Scrubbed Digester Gas/Natural Gas
Utility Services Municipal Water Cooling Water Electricity @ 480 Vac Sewer
Control Interfaces Data communications link(s) to Plant Buyer's control center / dispatch facility & FCE monitoring Station

Note: 1) Whenever the plant is not producing power (such as during startup, shutdown, and standby), electric power for plant auxiliaries must be back-fed from the electric grid.

6.0 Plant Operating Requirements

The plant will be designed to enable operation in the following modes:

1. Heatup and Cooldown of the Plant.
2. Hot Standby operation of the Plant (no power generation).
3. Power generation operation with a Fuel Cell Stack Module containing "Field Trial" generation stacks at up to 1 MW plant power output. Major design criteria that define the plant's operation at rated power output are listed in Table 7.

TABLE 7
POWER GENERATION OPERATION
NATURAL GAS / SCRUBBED DIGESTER GAS
OR DIGESTER GAS FUEL
"FIELD TRIAL" GENERATION STACKS

Design Case:	Rated Output At BOL	Maximum Power Output at EOL
Stack Module Power Output (net ac at inverter terminals)	1 MW	1 MW
Fuel Gas Steam/Carbon Ratio (Not including carbon in CO_2)	2:1	2:1
Fuel Utilization	74 %	--

Notes: BOL = Beginning of life, EOL = End of life

Additionally, the plant will be designed to accommodate operation with future technology replacement Fuel Cell Stack Modules as follows:

1. Power generation operation with a Fuel Cell Stack Module containing "Early Production Unit" generation stacks at up to 1.2 MW plant power output.
2. Power generation operation with a Fuel Cell Stack Module containing "Mature" generation stacks at up to 1.5 MW plant power output.

7.0 Process Systems Design

The functionality of each of the major process systems is described below.

Fuel Gas Preparation System

The Fuel Gas Preparation System will:

1. Receive "pipeline quality" scrubbed digester gas and remove sulfur compounds/ odorants and other contaminants from it at ambient temperature in the Cold Gas Desulfurizers. The desulfurized scrubbed digester gas is used for anode fuel gas makeup (when the plant is in "natural gas" operating mode) and as the fuel gas for the Oxidant Supply System.
2. Control the flow of desulfurized fuel gas used for anode fuel gas makeup (either digester gas from the Digester Gas Conditioning System or scrubbed digester gas from the Cold Gas Desulfurizers), and continuously monitor its methane and oxygen concentrations to determine its fuel-based "carbon content".
3. Simultaneously humidify (using purified water from the Water Treatment System) and preheat the desulfurized fuel gas in the Fuel Humidifier (part of the Heat Recovery Unit [HRU]). The water injection rate is controlled to maintain the required steam-to-carbon ratio, which is set by the fuel cell stack and/or Preconverter operating requirements.
4. Prepare the resultant fuel gas mixture for use as anode fuel gas by:
   - Passing it through a Fuel Deoxidizer to remove oxygen (normally present in peak shave gas and digester gas).
   - Partially reforming it in a Preconverter to eliminate C_2+ hydrocarbons and generate an initial hydrogen gas concentration.
   - Superheating it in a Fuel Superheater (part of the HRU).
5. Deliver the anode fuel gas to the Fuel Cell Stack Module.

Note that operation of the Fuel Gas Preparation System is modified when desulfurized/treated digester gas is used for fuel gas makeup:

- The steam-to-carbon ratio required with treated digester gas ignores the carbon atoms present as CO_2 in the gas (per the catalyst supplier's guideline, since CO_2 also introduces oxygen atoms into the system).
- The Deoxidizer must be operated at a higher exit temperature (1000°F) with treated digester gas than during peak shave gas operation (875-900°F) to ensure that O_2 is completely consumed by reaction with methane (because methane is less reactive than the propane present in peak shave gas).

The metallurgy of the piping and equipment will be selected to ensure the purity of the anode fuel gas.

Nitrogen Gas Supply System

The Nitrogen Gas Supply System will provide low-pressure nitrogen gas for purging

operations and protecting the Fuel Cell Stack Module during Plant Shutdown/Trip modes. The nitrogen is stored in several pressurized gas bottles, and will be used for:

1. Providing an inert gas curtain in the fuel cell cathode exit piping when the plant is placed in Shutdown mode to avoid a vacuum condition in the stack module as the module cools down,
2. Purging of the fuel gas piping and fuel cell anodes when the plant is placed in Shutdown mode to avoid nickel carbonyl formation (within the Prereformer and the fuel cell reforming units (RU)) and condensation of the moisture.

Additional nitrogen gas will be required for use in certain maintenance activities, and will have to be supplied separately. These maintenance activities include:

1. Purging of the fuel gas piping and fuel cell anodes prior to the first start-up.
2. Purging of the fuel gas piping prior to and following maintenance activities.
3. Purging of the Cold Gas Desulfurizers, SulfaTreat Vessel, and Digester Gas Polishers before change-out.

The metallurgy of the piping and equipment will be selected to ensure the purity of the anode fuel gas.

Heat Recovery System

The Heat Recovery System will:

1. Collect the cathode exhaust gas exiting the Fuel Cell Stack Module.
2. Polish the cathode exhaust gas to remove residual methane and carbon monoxide emissions and thereby maximize the temperature of the flue gas upstream of the Fuel Superheater.
3. Utilize waste heat from the cathode exhaust gas to:
   - Humidify and preheat the digester gas or natural gas/scrubbed digester gas feed
   - Superheat the anode fuel gas
4. Vent the cooled cathode exhaust gas to the atmosphere.

The system includes a portion of the cathode exhaust gas piping to the Heat Recovery Unit (HRU). The HRU includes an internal bypass around the Fuel Humidifier to limit heat addition in the humidifier; it will be used to prevent the exit temperature of the humidified fuel gas from exceeding the operating temperature limit of the downstream Preconverter. The HRU also includes a nozzle for extracting flue gas from the exit of the HRU to a King County waste heat recovery system (being designed by others), and a second nozzle to return the cooled flue gas to the HRU exhaust stack.

Oxidant Supply System

The Oxidant Supply System will:

1. Compress ambient air for cathode oxidant makeup.

2. Collect, mix with the pressurized air stream, and catalytically oxidize the anode exhaust gas from the Fuel Cell Stack Module System.
3. Generate cathode oxidant gas at the flow rate, composition, and temperature required for fuel cell power generation.
4. Deliver the oxidant gas to the Fuel Cell Stack Module System.

The Oxidant Supply System will also burn desulfurized natural gas/scrubbed digester gas from the Fuel Gas Preparation System in the pressurized air stream to generate a hot effluent gas at the temperatures and flow rates required for controlled heating and cooling of the fuel cell stacks during plant startup, shutdown, and standby operation. Treated digester gas from the Digester Gas Conditioning System cannot be used because the heating value of this gas is too low for the Oxidizer's standard natural gas burner.

The Oxidant Supply System is designed to integrate the operation of the fuel cell anodes and cathodes during power generation by:

1. Utilizing the residual fuel energy and sensible heat in the anode exhaust gas to heat air to the required oxidant gas temperature, and
2. Recirculating the carbon dioxide generated in the fuel cell anodes back to the fuel cell cathodes to support the cathode reactions.

The metallurgy of the piping and equipment will be selected to ensure the purity of the oxidant gas.

Fuel Cell Stack Module System

The Fuel Cell Stack Module System will:

1. Receive superheated anode fuel gas from the Fuel Gas Preparation System and hot cathode oxidant gas from the Oxidant Supply System,
2. Generate dc electric power for the Inverters by converting the fuel energy in the anode fuel gas to electrical energy, and
3. Discharge anode exhaust gas to the Oxidant Supply System and cathode exhaust gas to the Heat Recovery System.

The Fuel Cell Stack Module System will include one Fuel Cell Stack Module (containing four fuel cell stacks). Inside the fuel cell stacks, anode fuel gas will be reformed and electrochemically reacted with the cathode oxidant gas to generate dc power according to the following reactions:

$CH_4 + H_2O \leftrightarrow CO + 3\,H_2$	(Methane Reforming Reaction)
$H_2O + CO \leftrightarrow H_2 + CO_2$	(Shift Reaction)
$H_2 + CO_3^{=} \rightarrow H_2O + CO_2 + 2e^-$	(Anode Half-Cell Reaction)
$CO_2 + \frac{1}{2}\,O_2 + 2e^- \rightarrow CO_3^{=}$	(Cathode Half-Cell Reaction)

The Fuel Cell Stack Module interfaces with the BOP process piping will be designed to facilitate changeout of the Fuel Cell Stack Module.

The Fuel Cell Stack Module will be gas-tight to provide environment containment at operating pressures up to 2 psig. A summary of operating parameters for Fuel Cell Stack Modules containing "Field Trial" generation stacks is listed in Table 8.

TABLE 8

FUEL CELL STACK MODULE OPERATING PARAMETERS
"FIELD TRIAL" GENERATION STACKS

Proprietary Information –
Not Available for Publication

Water Treatment System

The Water Treatment System will:

(1) Purify chlorinated municipal water for use as makeup to the HRU's Fuel Humidifier.

(2) Provide a 12-hour reserve capacity of treated water for use during water purification equipment outages.

The system will be designed for operation with makeup water that meets the KCPP site-specific and reference water criteria in Table 5, and will be easily amenable to upgrades to accommodate makeup water qualities outside these design limits.

The Water Treatment system will be designed for continuous, reliable, and automatic operation.

Instrument Air System

The Instrument Air System will produce dry, compressed air and distribute it to pneumatically operated control valves and panel purges on the balance of plant (BOP) equipment. Oil free, rotary type Air Compressors will be used.

Electrical Balance of Plant

The Electrical Balance of Plant will convert the dc electric power generated by the Fuel Cell Stack Module System to ac electric power. It will contain all electrical system protective devices and the distribution and control devices for auxiliary loads.

Digester Gas Conditioning System

The Digester Gas Conditioning System will treat and condition the raw digester gas for use as fuel to the anode side of the fuel cells. Figure 1 depicts the schematic for processing the digester gas upstream of the Fuel Cell Stack Module. Raw digester gas will be passed through a knockout drum to remove entrained liquids and then fed to a compressor. The compressed gas will be cooled against cooling water and passed through a second knockout drum, where condensed liquids will be removed. The cooling water and condensed liquids will be returned to the sewage treatment plant.

The cooled compressed digester gas will be fed through a SulfaTreat bed for bulk sulfur removal. The bed material consists of ferric and triferric oxides supported on the surface of an inorganic substrate. The spent bed material is considered environmentally benign and should not pose any disposal problems.

Effluent digester gas from the SulfaTreat bed will be passed through KOH impregnated activated carbon beds (two in series) to remove trace sulfur compounds. The impregnated KOH assists in the removal of COS and SO_2. Trace quantities of siloxanes and organic chlorine compounds that have been reported as present in the digester gas are also expected to be removed by the KOH impregnated activated carbon beds, based on a discussion of theoretical considerations with David Ainsworth of Cameron Carbon Inc. Cameron Carbon has experience with carbon beds used in the semiconductor

industry for siloxane capture; the bed sizing was based on theoretical estimates. Treated digester gas will be supplied to the Fuel Gas Preparation System upstream of the HRU's Fuel Humidifier.

Metallurgy selection for piping and equipment will be based on corrosion resistance to digester gas and the anode fuel gas purity requirement.

8.0 Environmental Emissions and Effluents

Continuous effluent streams from the plant during normal operation are as follows:

- The major continuous gaseous effluent from the plant is the fuel cell's cathode exhaust gas that passes through the Heat Recovery Unit and exits to the atmosphere. Air pollutant emissions in this exhaust gas are nearly negligible. SO_x emissions are essentially zero because the fuel gas feed to the fuel cells contains less than 0.1 ppmv sulfur, and NO_x emissions are low due to the low operating temperatures in the Oxidizer and fuel cells. Methane and carbon monoxide emissions are reduced to nearly zero by the Polisher in the Heat Recovery Unit.
- The major continuous liquid effluent from the plant during normal operation is the reject/regeneration/backwash water from the Water Treatment system. The quality and temperature of the effluent water stream are expected to be satisfactory for its disposal into a municipal sewer. The plant will have two additional liquid effluents whenever it is fueled with digester gas. The cooling water used to cool the digester gas in the Digester Gas Aftercooler will be dumped to an open sewer, and process condensate generated in the Digester Gas Conditioning System will drain into a closed sewer. This water will contain oil from the Digester Gas Compressor and trace sulfur from the digester gas. Both sewers will return the liquid effluent to the sewage treatment plant's water treatment facilities.

Solid wastes generated in the plant require disposal intermittently. These include spent sulfur absorbents and deactivated catalysts. The spent waste material is collected in waste bins prior to being shipped off-site. The Preconverter catalyst and oxidation catalysts (from the Deoxidizer, Oxidizer, and HRU Exhaust Gas Polisher) are suitable for recycle/sale to catalyst reclaimers. The spent sulfur absorbent (from the Cold Gas Desulfurizers and Digester Gas Polishers) are assumed to be returned to the supplier for regeneration or disposal, and the SulfaTreat absorbent is disposed of as a non-hazardous waste.

Other intermittent wastes will occasionally be generated, such as used lube oil that must be replaced per equipment vendor specifications.

Rainwater or washdown water from the site can be directed to a stormwater drain. Oil leakage beneath rotary equipment is contained to allow clean up during regular maintenance.

9.0 Layout

Most of the plant equipment is packaged in modules or skids and placed on concrete foundations. The skidding philosophy consists of combining skids to minimize the plant footprint and reduce interconnection activities in the field. The plant requires a rectangular footprint. The plant height will not exceed 32 feet.

The plant's piping and structural interfaces with the Fuel Cell Stack Module will be designed to be identical to those planned for FCE's standard natural gas-fueled single module DFC® Power Plants.

An access zone capable of supporting the module transporter and the crane used to install and remove the Fuel Cell Stack Module and other equipment skids, and which will enable access for catalyst/adsorbent/brine salt removal and replacement, will be provided adjacent to the physical plant boundary. A laydown area will be provided adjacent to the plant during construction.

Appendix B
Demonstration Project Test Plan
(July 2004)

Testing Plan

King County South Treatment Plant

Fuel Cell Demonstration Project

July 2004

CH2MHILL

Table of Contents

TABLE OF CONTENTS ..... **III**

INTRODUCTION **1**

BACKGROUND **3**

PROJECT DESCRIPTION 3
FUEL CELL SYSTEM 5
Fuel Cell Stack Module *6*
Electrical Balance of Plant (EBOP) *7*
Natural Gas Treatment System *7*
Digester Gas Conditioning System *8*
Anode Fuel Gas Treatment Controls *8*
Anode Exhaust Gas *10*
Oxidant Supply System *10*
Cathode Exhaust Gas *11*

STAFFING ORGANIZATION **13**

OPERATIONS AND TESTING STAFF 13
PEER REVIEW TEAM 14
Peer Review Team Meeting Schedule *16*

OPERATIONS AND TESTING PERIOD **17**

SCHEDULE 17
FUEL CELL EMISSION TESTING 17
List of Test Methods and Locations *18*
Exhaust Gas Test Methods *18*
Description of Test Methods *19*
Additional Testing Requirements *21*
Sampling Locations and Types of Samples *21*
PERFORMANCE GOALS AND METRICS 26
DATA RECORDING FOR PERFORMANCE GOALS 28

Introduction

The Operations and Testing Plan for the South Treatment Plant (STP) Fuel Cell is intended to provide guidance to King County Operations and Maintenance (O & M) staff. The two-year operations and testing phase has two objectives:

(1) That molten carbonate fuel cell technology can be adapted to use anaerobic digester gas as a fuel gas; and

(2) That a nominal plant power output target of 1 MW (net ac) can be achieved using either digester gas or natural gas/scrubbed digester gas.

Data will be gathered and analyzed and reports will be written. Semi-annual meetings with also be held five times during the two year period (including one meeting at the beginning and one at the end) with the Peer Review Team to review the results of the operations and testing phase and suggest changes for the next six months of operations and testing.

The stakeholders on this project are:

- King County
- Fuel Cell Energy
- U.S. Environmental Protection Agency (EPA)
- CH2M HILL
- Brown and Caldwell

Background

Project Description

In cooperation with the U.S. Environmental Protection Agency and Fuel Cell Energy Inc., King County is sponsoring the world's largest demonstration project of molten carbonate fuel cell (MCFC) (1 mega watt (MW)) using digester gas. CH2M Hill and Brown and Caldwell are responsible for assisting King County in coordination and management of the overall project with direct responsibility for day to day management of the project, monitoring and reporting of project status, design and utility interface requirements, assistance during construction, start-up, testing, and operation and analysis and reporting of the results of the demonstration project.

Municipal wastewater treatment plants that treat wastewater produce solids, which are typically treated through anaerobic digestion and produce large quantities of gas that is about 60% methane (CH_4) and 40% carbon dioxide (CO_2). Currently, most small plants simply burn the gas in a flare. Larger plants more frequently reuse the combined gases on site for heat or power, or remove the CO_2 in order to sell the remaining gas. Using a MCFC can eliminate CO_2 removal costs and make more efficient use of gas resources while generating electricity.

The King County demonstration plant is sized to produce 1 MW of power. Waste heat from the fuel cell power plant will be integrated into the existing heat distribution system offering further efficiency. MCFC is one of the most efficient of the fuel cell technologies under development. Fuel cells produce electric power directly through electrochemical reactions using air and fuels such as natural gas, landfill gas, and anaerobic digester gas. By avoiding the two step process of conventional combustion technology, where fuel is first burned and then heat is used to produce power, fuel cells are most energy efficient, better for the environment, quieter, and ultimately more cost effective. A general diagram of how a fuel cell works is shown in Figure 1 and a process flow diagram in Figure 2.

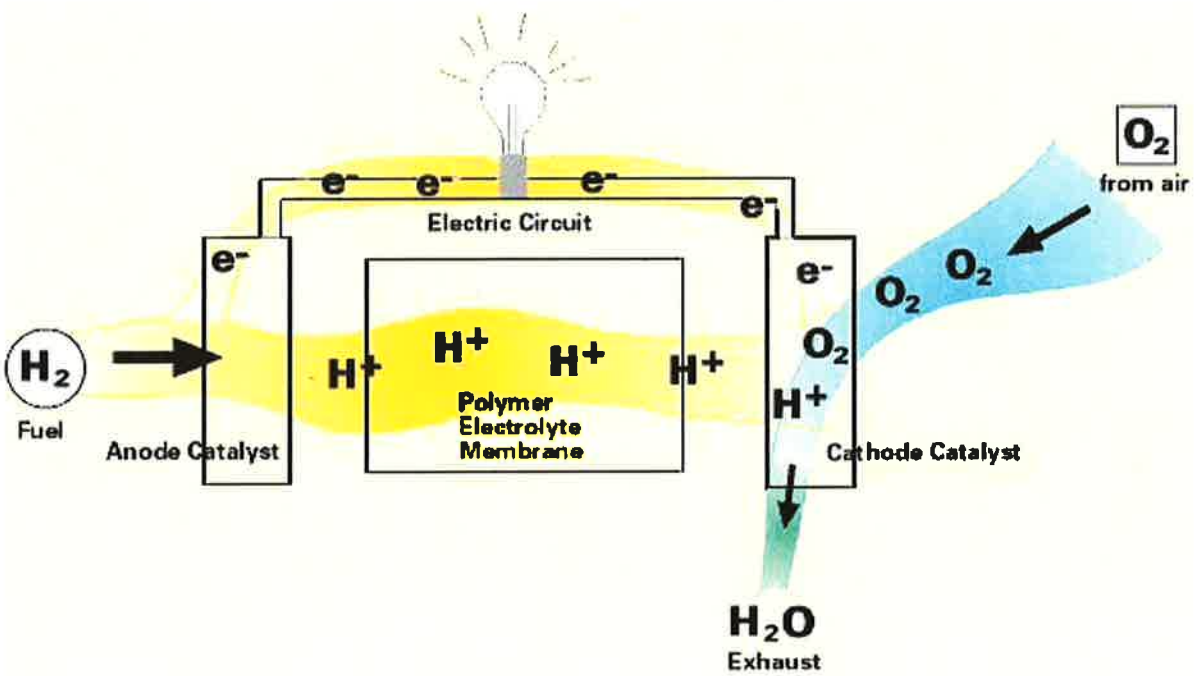

Figure 1 – How a Fuel Cell Works

(Source: www.fuelcells.org)

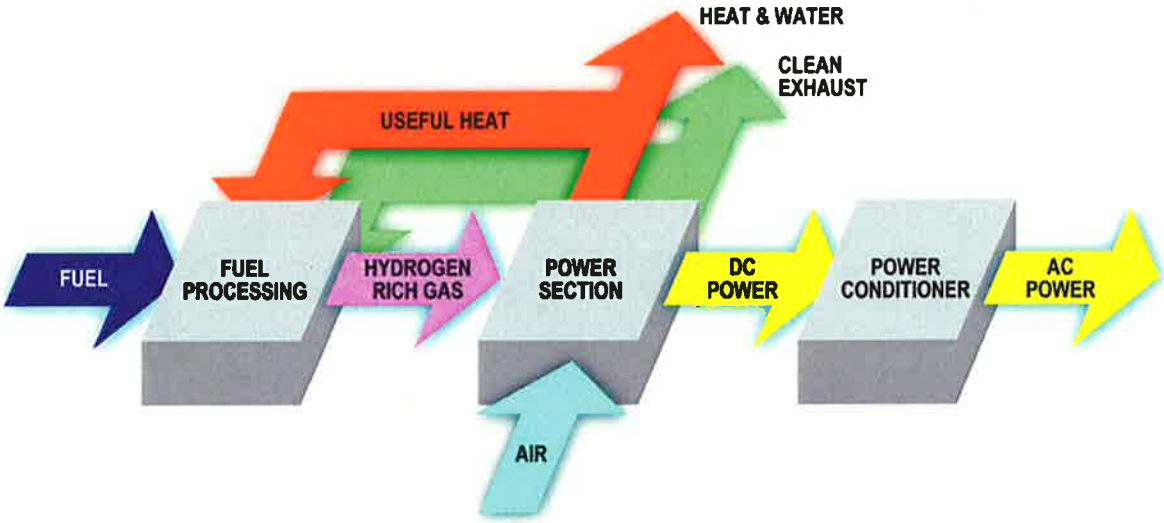

Figure 2 – The Fuel Cell Process Flow Diagram

(Source: Fuel Cell Energy)

Fuel Cell System

A process flow diagram of the fuel cell system is shown in Figure 2. The system contains the following components:

- Fuel cell stack module
- Electrical Balance of Plant (EBOP)
- Natural gas conditioning
- Digester gas treatment
- Anode fuel gas treatment
- Anode exhaust gas treatment
- Oxidant supply
- Cathode exhaust gas treatment

Ancillary Systems

- Heat recovery system
- Water treatment system
- Instrument air system
- Nitrogen gas supply system (used when plant is shutdown)

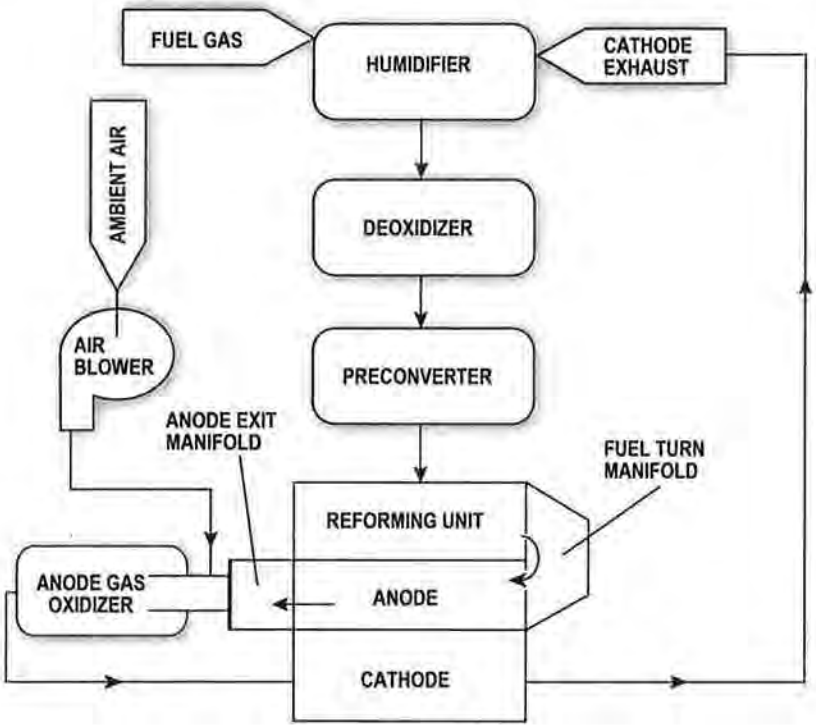

Figure 3 – Fuel Cell System Components

(Source: Fuel Cell Energy)

Fuel Cell Stack Module

Desulfurized fuel gas (either natural gas or digester gas) is combined with treated water to produce a fuel gas/steam mixture suitable for feeding as anode fuel gas to the Fuel Cell Stack Module. The steam is required in the Preconverter and Fuel Cell Module as a reactant for the reforming and shift reactions that generate hydrogen from the natural gas fuel.

The following controls and instrumentation allow for the proper operation and control of the fuel cell module:

Stack Module Temperature Controls

Overall, temperature control of the Fuel Cell Stack Module is achieved the Oxidant Supply System. Both the temperature and flow of oxidant gas from the Oxidizer is directly controlled to meet the required operating conditions. During Plant Heatup and Plant Cooldown, a temperature ramp generator provides the temperature setpoints for the Oxidizer effluent/cathode inlet gas. During Power Generation and Hot Standby mode, oxidant air flow is controlled to maintain the stack temperature between preset inlet and outlet limits while attempting to maximize the overall module temperature.

The temperature of the anode fuel gas entering the Fuel Cell Stack Module is not controlled, but is dependent on the temperature and flow of cathode exhaust gas through the Fuel Superheater. The resultant temperature typically lies between 970 and 1050°F. Heat losses from the anode fuel gas line are expected to be minimal because of the close coupling of the Fuel Cell Stack Module and Heat Recovery Unit.

The Fuel Cell Stack Module contains four fuel cell stacks identified as stacks A, B, C, and D.

Stack Module Pressure Controls

The pressures within the Fuel Cell Stack Module are not controlled but are the result of the accumulated system pressure drops through the plant. The pressure difference between the anode inlet/outlet and the cathode inlet are closely monitored, as they are an indication of the level of potential leakage from the anode to the cathodes across the cells.

Fuel Cell Stack Voltage Controls

The Fuel Cell Stack Module includes instrumentation for monitoring the voltages of individual fuel cells and voltages generated across groups of fuel cells within the individual stacks.

Control of Fuel Utilization

During power generation, the fuel gas flow rate and current drawn from the Fuel Cell Stack Module will be carefully coordinated. It is critical that the fuel cell stacks not be starved of fuel during any operation, including transients, as this will reduce the life and performance of the stacks. This is because the amount of power (current) that can be safely drawn from the Fuel Cell Stack Module is directly dependent upon the theoretical hydrogen content (TH_2) of the fuel gas feed stream. The TH_2 of the fuel gas stream is the maximum amount of hydrogen that can be generated from the fuel gas, based on 100% completion of the hydrocarbon reforming and shift reactions. The fraction of the fuel gas stream's TH_2 that is allowed to react within the fuel cell anodes to generate electric power is the fuel utilization (U_f). Significant deviation between target and actual fuel utilization will be alarmed.

DC Power Controls

The electrical outputs of the four fuel cell stacks are connected in parallel to a common dc bus. The positive (cathode) terminal is resistance grounded. The stacks are electrically isolated by blocking diodes. The dc current can be converted to either 400 Vac or 150 Vac. In both cases, the inverter outputs are then connected to the 480 Vac power system via step-up isolation transformers.

Electrical Balance of Plant (EBOP)

The EBOP is an outdoor, non walk-in enclosure containing the Power Conditioning System (PCS), dc power fuses, dc grounding circuit, dc isolation diodes, ac utility interconnection circuit breaker and protective relaying, distributed control system (DCS), UPS, and low voltage distribution equipment.

The PCS converts dc power from the Fuel Cell Stack Modules to ac power for export and to meet the plant's auxiliary loads. The PCS inverters employ pulse width modulation (PWM) of the power semiconductors to provide ac electric power at 480 volt/3-phase/60 Hz that meets the requirements of IEEE 519. The power is then sent to the grid.

Natural Gas Treatment System

The natural gas treatment portion of the Fuel Gas Preparation System receives natural gas at the plant battery limit and removes sulfur contaminants from it at near-ambient temperature in Cold Gas Desulfurizers. The desulfurized gas is used for anode fuel gas and/or as fuel to the Oxidizer's main burner and pilot.

Gas Supply and Plant Isolation Control

Natural gas comes from two different sources, the digester gas scrubbers (source 1) or the utility (Puget Sound Energy – source 2). If the digester gas scrubbers do not produce gas that meets the specifications of Puget Sound Energy, to whom they sell their gas, the gas is flared and no natural gas is sent to the fuel cell. In this situation the fuel cell receives natural gas directly from Puget Sound Energy.

The natural gas from either source passes through a custody transfer station comprised of a filter, pressure regulation, and flow metering at a flow meter adjacent to the fuel cell site. Whether or not the gas comes directly from Puget Sound Energy or the plant, the County is charged for the gas. The gas enters the plant through a manual isolation valve and pressure control valve, which reduces it down to about 50 psig. This pressure control is necessary to maintain a nearly constant pressure in the downstream Cold Gas Desulfurizers, whose performance is impacted by system pressure.

Natural Gas Desulfurization Controls

The natural gas from Puget Sound Energy contains carbonyl sulfide (COS), which must be removed. A second COS Cold Gas Desulfurizer was installed upstream of the carbon Cold Gas Desulfurizer. The second vessel has special media (copper oxide and aluminum oxide) that removes the COS. All natural gas flows through the vessel with the COS removal media and then through the vessels with the carbon media.

After the COS Cold Gas Desulfurizer, the gas is fed into a Natural Gas Heater, which heats the incoming gas to 60°F whenever it enters at a lower temperature. This ensures that the

downstream Cold Gas Desulfurizers remain at or above 60°F, as their performance drops significantly at lower temperature. Natural gas is then routed to the Cold Gas Desulfurizers. The Cold Gas Desulfurizers remove sulfur compounds (mostly H_2S, but also trace amounts of CS_2, SO_2, mercaptans, sulfides, disulfides, and thiophenes) from the natural gas to less than 0.1 ppmV. The quantity of sulfur compounds that can be adsorbed on the beds is dependent upon the bed operating pressure and temperature and the inlet gas flow and composition. Each of the beds has sufficient capacity to desulfurize the feed gas at rated conditions for 27 weeks of operation. The two Cold Gas Desulfurizers will normally be operated in series.

Digester Gas Conditioning System

Raw digester gas is supplied to the fuel cell system by the South Plant. The Digester Gas Conditioning System treats the raw digester gas to make it suitable for use as fuel for the fuel cells.

The Digester Gas Conditioning System performs the following functions:

- Receives raw digester gas and compresses it to about 26 psig using Digester Gas. The compression system skid includes Digester Gas Feed KO Drum at the compressor suction. Digester Gas Aftercooler and Digester Gas Discharge KO Drum are provided on the compressor discharge. Downstream of the compressor skid the Digester Gas High Efficiency Oil Filter is provided to reduce entrained oil in the gas to 0.5 ppmw. Condensed liquids removed from the digester gas are returned to the water treatment plant.
- Treats the cooled compressed digester gas by passing it through SulfaTreat Vessel for bulk hydrogen sulfide (H_2S) removal, which provides bulk H_2S removal to less than 10 ppmV, and then through Digester Gas Polishers for trace sulfur compound and siloxane removal. The remaining sulfur compounds (mostly H2S) are removed to less than 0.1 ppmV. The Sulfatreat bed has sufficient capacity to desulfurize the feed gas at rated conditions for 40 weeks of operation. Each of the polisher beds has sufficient capacity to treat the digester gas at rated conditions for 27 weeks of operation.

Anode Fuel Gas Treatment Controls

The anode fuel gas treatment portion of the Fuel Gas Preparation System performs the following functions:

- Simultaneously humidifies the fuel gas and superheats the resultant fuel gas in the Fuel Humidifier (part of Heat Recovery Unit (HRU)) to meet the temperature requirements of the downstream fuel treatment equipment using waste heat recovered from the fuel cell cathode exhaust.
- Treats the preheated fuel gas in Fuel Deoxidizer to remove oxygen. Oxygen removal is required to protect the Preconverter and fuel cell catalysts from oxidation. Oxygen is normally present in digester gas and in natural gas, which has been supplemented with peak shave gas (PSG), and may be present in small amounts in natural gas. The gas heats up as it passes through the Fuel Deoxidizer because the oxygen removal reactions are exothermic.

- Partially reforms the deoxidized fuel gas in Preconverter to eliminate C_2+ hydrocarbons and generate an initial hydrogen gas concentration. The high molecular weight (C_2+) hydrocarbons must be reformed away to avoid carbon deposition in the fuel cell stacks at elevated temperatures, and a small hydrogen gas partial pressure must be established in the gas to maintain a reducing environment. The gas cools as it passes through the Preconverter due to the endothermic reforming reactions.
- Heats the Preconverter effluent gas in the Fuel Superheater (part of the HRU) to the temperature required by the fuel cells using waste heat recovered from the fuel cell cathode exhaust. The resultant anode fuel gas is fed to Fuel Cell Stack Module.

The desulfurized fuel gas/vaporized water mixture exiting the Fuel Humidifier must be treated in Deoxidizer and Preconverter before it can be fed to the fuel cell stack anodes.

Fuel Humidifier

The Fuel Humidifier absorbed duty is controlled by bypassing a portion of the cathode exhaust gas around the Fuel Humidifier's tube bundle.

Fuel Deoxidizer

The fuel gas from the Fuel Humidifier is routed to Fuel Deoxidizer, which catalytically reacts any free oxygen (O_2) in the fuel gas to extinction. The oxygen is consumed by oxidizing methane (digester gas), propane/propylene/butane (peak shave gas), or C_2+ hydrocarbons (natural gas) in the fuel to form carbon dioxide and water. The reaction is exothermic and results in an increase in gas temperature.

Oxygen removal is required to prevent oxidation of the Preconverter and fuel cell catalysts. Although oxygen is not expected to be present in the scrubbed digester gas, the raw digester gas will contain up to 1.4 volume percent. Oxygen may also be present in the natural gas supply, up to 5 volume percent.

Preconverter

The fuel gas exiting the Deoxidizer is routed to Preconverter, which adiabatically reforms all of the higher molecular weight (C_2+) hydrocarbons and a small fraction of the methane in the fuel gas to form H_2, CO and CO_2. Elimination of higher hydrocarbons is important to avoid carbon deposition in the fuel cell stacks, and establishment of a small hydrogen gas partial pressure ensures a reducing environment at the inlet to the fuel cell Reforming Units (RUs).

The overall process is endothermic and results in a temperature decrease across the Preconverter. The temperature change across the Preconverter is indicative of its performance. A temperature drop of 175 - 250°F is normal, whereas a smaller temperature drop indicates loss in catalyst activity (possibly due to sulfur poisoning or oxidation). A very small temperature drop or a rise in temperature indicates that the Preconverter catalyst has been oxidized and that oxygen is present and reacting with fuel gas in the Preconverter.

Preconverter Afterfilter

The Preconverter effluent gas is routed to Preconverter Afterfilter to remove catalyst fines that may be carried over.

Fuel Superheater

Fuel gas from the Preconverter Afterfilter is routed to Fuel Superheater of Heat Recovery Unit, where it is heated further against hot cathode exhaust gas before being fed to Fuel Cell Stack Module. Operation of this heater is uncontrolled; its performance (including fuel gas outlet temperature) is entirely dependent upon the process conditions and heat exchange surface area. The temperature of the fuel gas exiting the Fuel Superheater normally remain between 980°F and 1070°F during all power generation and standby operating conditions.

Anode Fuel Gas Supply Controls

The gas exiting the Fuel Superheater is routed to the anode fuel gas inlet of the Fuel Cell Stack Module through an electrically heat-traced pipe. The electric heat tracing is designed for high temperature operation to limit anode fuel gas heat loss, and should ensure that the gas temperature always remains above 968°F.

Anode Exhaust Gas

Anode exhaust gas from the Fuel Cell Stack Module is routed to Oxidizer, where the remaining fuel components in the low BTU anode gas are catalytically oxidized generating CO_2, water vapor and heat.

Oxidant Supply System

The Oxidant Supply System performs the following functions:

- Compresses ambient air to be used as cathode oxidant.
- Mixes the compressed air with anode exhaust gas from the Fuel Cell Stack Module and catalytically oxidizes the fuel components in the anode exhaust gas.
- Burns desulfurized natural gas to provide supplemental heating of the compressed air/anode exhaust gas stream.
- Generates cathode oxidant gas at the flow rate and temperature required for various plant operating modes.
- Delivers the hot oxidant gas to the cathode side of the Fuel Cell Stack Module.

The Oxidant Supply System integrates the operation of the fuel cell anodes and cathodes during power generation by:

- Utilizing the residual fuel energy and sensible heat in the anode exhaust gas to heat air to the required oxidant gas temperature, and
- Recirculating the carbon dioxide generated in the fuel cell anodes to the fuel cell cathodes to support the cathode reactions.

The Oxidant Supply System consists of an Air Blower and thermal/catalytic Oxidizer.

Air Blower

Air Blower is a rotary air compressor with a variable speed drive to provide a wider range of operation. The blower provides up to 5000 scfm of oxidant air to the Oxidizer and the Oxidizer's sight glasses and flame detector cooling air requirements.

Oxidizer

Oxidizer consists of a natural gas burner and fuel piping train, a thermal reactor, and a catalytic reactor.

The Oxidizer controls are designed to meet the following three functional requirements:

- Burner fuel/air controls – Controls burner operation including firing rate, air-to-fuel ratio, burner/pilot sequencing, and flame safety systems. The air-to-fuel ratio is controlled to achieve a value of 22.
- Total Airflow Controls – Ensures that total airflow meets the requirements of the Fuel Cell Stack Module.
- Oxidation Catalyst Temperature Controls – Ensures that the oxidation catalyst operating temperature is kept high enough for proper catalyst operation.

Cathode Exhaust Gas

Cathode exhaust gas from the Fuel Cell Stack Module is routed to the "shell" side of Heat Recovery Unit, where it is used as the heat source for Fuel Superheater and Fuel Humidifier.

King County Fuel Cell

Staffing Organization

King County will operate and maintain the STP Fuel Cell Facility following the operation and maintenance (O & M) manuals provided by FCE and the using the skills and knowledge provided in the training given by FCE.

Operations and Testing Staff

The Fuel Cell Energy, King County, and Consultant Team members, and their responsibilities are described below.

Name	Role	Responsibility	Phone and email
Greg Bush	King County Project Manager	Oversight of FCE and CH2M HILL contracts	(206) 684-1164 greg.bush@metrokc.gov
Eddie Tate	King County Construction Manager	Oversight of Hawk Construction	(206) 263-6602 Eddie.tate@metrokc.gov
Carl Mack	King County Project Engineer	Oversight of FCE startup and commissioning	Carl.mack@metrokc.gov
Mike Fischer	King County South Treatment Plant (STP) Superintendent	Plant superintendent	Mike.fischer@metrokc.gov
Rick Butler	King County STP Process Control	Supervisor of process control	(206) 684-2460 rick.butler@metrokc.gov
Carol Nelson	King County STP Process Control	Main contact for fuel cell operations	(206) 684-2466 carol.nelson@metrokc.gov
Frank Stratton	King County STP Maintenance	Main contact for fuel cell maintenance	Frank.stratton@metrokc.gov
Tommy Edwards	King County Electrical Inspector	Electrical inspector	Tommy.edwards@metrokc.gov
Jim Faccone	King County Health and Safety	Assist in developing safe operation and testing procedures	Jim.faccone@metrokc.gov
Dave Hennessy	FCE Project Manager	Oversight of FCE team	
Dan	FCE MW Field	Oversight of commissioning,	203-205-2457

Name	Role	Responsibility	Phone and email
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Winston Spencer	FCE MW Team Leader	Onsite Supervision during commissioning, testing and operations	203-825-6000 wspencer@fce.com
Eleanor Allen	Consultant Team Project Manager	Oversight of CH2M HILL/Brown and Caldwell team	(425) 233-3441 eallen@ch2m.com
Jaimie Hennessy	Design Manager	Point person for design-related issues	(206) 749-2298 jhennessy@brwncald.com
Mark Corsentino	Project Engineer	Assist King County in gathering and analyzing data	(425)-233-3184 mcorsent@ch2m.com

Peer Review Team

A Peer Review Team has been formed of experts in the industry. The Peer Review Team will meet semi-annually to review the results of the testing of data and advise on any changes to the testing program. The Peer Review Team includes the following members:

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Dan Beachy	Fuel Cell Energy 3 Great Pasture Road Danbury, CT 06813	

Peer Review Team Meeting Schedule

The preliminary schedule for the Peer Review Team Meetings is:

Meeting 1 – November 2003 (at the South Treatment Plant)

Meeting 2 – September 2004

Meeting 3 – March 2005

Meeting 4 – September 2005

Meeting 5 - March 2006

Operations and Testing Period

The project is a two-year demonstration project with the overall goal of demonstrating the feasibility of using molten carbonate fuel cells at wastewater treatment plants.

Schedule

- Construction was completed in April 2004
- Start-up and commissioning took place from April to June 2004
- Operations began in June 2004

The two-demonstration period will have the following test phases:

1. **June – November 2004** : Run on natural gas and slowly turn system over to digester gas (Fuel Cell Energy operating the plant)
2. **November 2004 – June 2006:** Run on digester gas (King County operating the plant)

Fuel Cell Emission Testing

Emissions from fuel cells consist mostly of nitrogen (N_2), water vapor (H_2O), and carbon dioxide (CO_2). Fuel cells do generate some emissions of nitrogen oxides (NO_x), sulfur oxides (SO_x), carbon monoxide (CO), and volatile organic compounds (VOCs), but at significantly lower levels than combustion technology such as turbines or engines. Incomplete reaction of the digester gas could result in emissions of methane (CH_4) and hydrogen sulfide (H_2S). The fuel cells would be tested on both digester gas and natural gas during a two-year demonstration period from the fall of 2003 through the fall of 2005.

FCE conducted air emission sampling on natural gas in June 2004. This testing was done at 50 percent, 75 percent and 100 percent power to obtain certification from the California Air Resources Board (CARB). King County is planning on conducting air emission sampling of the fuel cell while operating on digester gas. The testing will include two separate source testing events. The first source testing event will occur in the spring of 2005. The second event will occur in the spring of 2006. Periodic monitoring of the process will occur according to the schedule indicated in Table 1. Sampling will be performed on the exhaust gas, water, and solid waste emitted from, or generated by, the fuel cell. Samples will also be collected on the fuel gas and water going into the process.

Sampling during each source testing event will consist of 3 runs (or samples) for each method on digester gas and 3 runs on natural gas. During the sampling the process will be running at 80% or more of its capacity. The fuel cell exhaust gas will be hot (approximately 600°F), which will impact how the sampling will be performed.

Periodic monitoring will be conducted on the fuel gas going into and out of the sulfa-treat system and on the water used by the process. This testing would be conducted on a daily,

weekly or monthly schedule depending on the operating parameter and additionally whenever process operation indicates that emission information is necessary. The emission test methods and the expected schedule for sampling is presented in Table 1 and discussed below.

List of Test Methods and Locations

Exhaust Gas Test Methods

The emissions from the fuel cell exhaust shall collected from the stack and monitored for oxygen (O_2), NO_x, CO, CO_2, sulfur dioxide (SO_2) and VOCs (both methane and non-methane organic compounds) using EPA methods.

- EPA Methods 1 and 2 Determination of Stack Gas Air Flow
- Method 3A - Determination of Carbon Dioxide and Oxygen Emissions from Stationary Sources (Instrumental Analyzer Procedure)
- EPA Method 4 Stack Gas Moisture Content
- EPA Method 5 Particulate Matter
- Method 6C - Determination of Sulfur Dioxide Emissions from Stationary Sources (Instrumental Analyzer Procedure)
- Method 7E - Determination of Nitrogen Oxides Emissions from Stationary Sources (Instrumental Analyzer Procedure)
- Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources
- Method 18 and 25A – Determination of Non-methane Organic Emissions and total Gaseous Organic Concentration
- EPA Method TO-14 for Speciated Hydrocarbons

Fuel Gas Test Methods

Fuel gas samples will be collected at the inlet of the fuel cell, which is also the outlet of the sulfa treat system, and at the inlet of the sulfa treat system. The fuel gas samples will be analyzed for the following:

- ASTM D 3588 for BTU content of the fuel
- Fixed gases by Summa Canister
- Hydrogen sulfide by hand held Jerome analyzer using Tedlar bag samples
- Siloxanes by test method AFT SIL-1
- Hydrogen chloride by color indicator tubes or as total inorganic chlorides, as chloride ion by EPA M3/300.0.

Water Test Methods

Water samples will be collected on the raw water, the water from the wastewater treatment system, cooling water and condensate from the Sulfatreat system. The following sampling methods will be used:

- pH by ASTM D1293
- Metals by EPA 200.8
- Total Sulfides by ASTM D4658
- Chlorides by ASTM D512

Description of Test Methods

EPA Methods 1 and 2, Determination of Stack Gas Air Flow

Velocity, temperature and airflow will be measured using 40 CFR 60, Appendix A, Methods 1 and 2. The stack gas velocity will be measured using a type S or type P (standard) pitot tube connected to a pressure measurement device such as an oil-filled inclined manometer or magnehelic gauge. The stack gas temperature is measured using a calibrated thermocouple probe connected to a digital thermocouple indicator.

Method 3A - Determination of Carbon Dioxide and Oxygen Emissions from Stationary Sources (Instrumental Analyzer Procedure)

EPA Method 3A will be performed to determine the molecular weight of the stack gas based on percent level measurements of the concentration of oxygen (O2) and carbon dioxide (CO2). The O2 and CO2 concentrations are measured using instrumental analyzers. Typically a paramagnetic analyzer is used to measure O2 and a non-dispersive infrared (NDIR) analyzer is used for CO2.

EPA Method 4 - Moisture Content

The moisture content of the stack exhaust will be determined using EPA Method 4. EPA Method 4 quantifies the percent moisture in the gas stream by weighing the (Method 5) impingers to 0.1 grams before and after each run with a triple beam balance. The net weight (final minus initial) was used to calculate the amount of moisture condensed from the known volume of stack gas collected.

EPA Method 5/202 – Particulate Matter

Particulate matter is withdrawn isokinetically from the source and collected on a glass fiber filter maintained at a temperature in the range of 120 ±14 C (248 ±25 F). The particulate mass, which includes any material that condenses at or above the filtration temperature, is determined gravimetrically after removal of uncombined water. Since the definition of particulate matter is not consistent in all rules, the particulate matter catch shall be itemized by weight as follows: (1) Filter Catch, (2) Probe Catch, (3) Impinger Catch, and (4) Solvent Extract to allow adjustment of the particulate matter determination to be consistent with the applicable regulation.

Method 6C - Determination of Sulfur Dioxide Emissions from Stationary Sources (Instrumental Analyzer Procedure)

This method is applicable to the determination of sulfur dioxide (SOx) concentrations in emissions from stationary sources. A gas sample is continuously extracted from a stack, and a portion of the sample is conveyed to an instrumental analyzer for determination of SO2 gas concentration using an ultraviolet (UV), nondispersive infrared (NDIR), or fluorescence analyzer. Since emissions from the fuel cell are expected to be less than 0.01 ppmv SO2, and ambient level analyzer capable of measuring in the 0 to 100 parts per billion by volume (ppbv) range will be used. Performance specifications and test procedures are provided to ensure reliable data.

Method 7E - Determination of Nitrogen Oxides Emissions from Stationary Sources (Instrumental Analyzer Procedure)

This method is applicable to the determination of nitrogen oxides (NO2) concentrations in emissions from stationary sources. A sample is continuously extracted from the effluent stream; a portion of the sample stream is conveyed to an instrumental chemiluminescent analyzer for determination of NO2 concentration. Since emissions from the fuel cell are expected to be less than 0.03 ppmv NOx, an ambient level analyzer capable of measuring in the 0 to 1000 parts per billion by volume (ppbv) range will be used. Performance specifications and test procedures are provided to ensure reliable data.

Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources

An integrated or continuous gas sample is extracted from a sampling point and analyzed for carbon monoxide (CO) content using a Luft-type nondispersive infrared analyzer (NDIR) or equivalent. This method is applicable for the determination of carbon monoxide emissions from stationary sources.

Method 18 and 25A – Determination of methane and Non-methane Organic Concentration

This method is applicable for the determination of methane and total gaseous organic concentration of vapors consisting primarily of alkanes, alkenes, and/or arenes (aromatic hydrocarbons). The concentration is expressed in terms of propane (or other appropriate organic calibration gas) or in terms of carbon. A gas sample is extracted from the source through a heated sample line and glass fiber filter to a flame ionization analyzer (FIA). Results are reported as volume concentration equivalents of the calibration gas or as carbon equivalents. A separate analyzer is used to determine the emissions of methane. The methane emissions are then subtracted from the total hydrocarbons measured by method 25A to determine the non-methane organic concentration (NMOC).

EPA Method TO-14 for Speciated hydrocarbons

EPA Method TO-14 uses a SUMMA polished canister for collection and storage of VOC samples. The summa canister is connected directly to the on/off valve. The evacuated canister is opened and the sample was collected. Analysis is by a gas chromatograph equipped with a mass spectrophotometer (GC/MS). Method TO-14 provides the concentration of a list of 38 hazardous air pollutants (HAPs).

Hydrogen Sulfide

Hydrogen sulfide (H2S) in the exhaust gas and fuel gas will be monitored using a hand held Jerome analyzer and gas collected in a summa canister

Total Siloxanes

Siloxanes can be analyzed by test method AFT SIL-1. Fuel gas samples will be collected in fuel cylinders.

Siloxanes in the fuel cell exhaust are collected in midget impinger sample trains. The impinger solution for the collection of siloxanes is methanol. Samples are collected by drawing the gas through impingers containing methanol at a rate of approximately 112 milliliters per minute for 2 hours. Each of the two impingers contained 20 ml of methanol. The contents of each impinger will be analyzed separately.

Fuel Energy Content

The fuel gas will be collected in fuel cylinders and analyzed by ASTM D-3588 for the BTU content of the fuel.

Fixed Gases: methane, carbon dioxide, oxygen, nitrogen.

SUMMA polished canisters can be used for the collection and storage of VOC samples. The summa canister is connected directly to the on/off valve. The evacuated canister is opened and the sample was collected. Analysis is by a gas chromatograph equipped with a mass spectrophotometer (GC/MS). Fixed gases by test method SM 2720C.

Hydrogen Chloride

The fuel gas will be collected in fuel cylinders and analyzed by EPA 26 for the hydrogen chloride content of the fuel. As an alternative, color detector tubes may be used to measure the chloride content of the fuel gas.

Water Samples

Water samples will be collected in amber glass jars and analyzed for pH by ASTM D1293, Metals by EPA 200.8, and Total Sulfides by ASTM D4658. Testing for pH and hardness will also be done.

Additional Testing Requirements

To support the source testing events, a manlift will need to be available to provide access to the sampling ports on the exhaust stack.

Sampling Locations and Types of Samples

The sampling locations, types of samples, and analytes are listed in Table 1 below. Areas of the fuel cell that will be monitored are also described.

Table 1 - Sampling Locations and Types of Samples

Location	Type of Sample	Analyte	Analytical Procedure	Frequency of Sampling
Raw digester gas[1] feed into SulfaTreat	Gas	BTU Content	ASTM D-3588, fuel cylinder	Quarterly by KC
		Flow	Inline flow meter	Continuous
		Temp	Inline temperature probe	Continuous
		H_2O	Inline temperature probe	Continuous
		H_2S	Jerome Analyzer/ Tedlar Bag	Annual Testing Event
		Siloxanes and Halides	GC-MS/Fuel Cylinder	Annual Testing Event
		Chlorides as Hydrogen Chloride	Color indicator tubes and impinger train	Annual Testing Event
Treated digester (LSG/ADG[1]) gas out of carbon and into fuel cell	Gas	Temp	Inline Thermocouple	Continuously
		Flow	Inline Flow Meter	Continuously
		H_2S	Jerome Analyzer/Tedlar Bag	Annual Testing Event
		Siloxanes	GC-MS/Tedlar Bag	Annual Testing Event
		H_2O	Fuel Cylinder	Quarterly
Fuel cell stack exhaust	Gas	SO_2	EPA M6C	Annual Testing Event
		H_2S	Jerome	Annual Testing

Location	Type of Sample	Analyte	Analytical Procedure	Frequency of Sampling
			Analyzer	Event
		NO_x	EPA M7E	Annual Testing Event
		H_2O	EPA M4	Annual Testing Event
		CH_4	EPA M18	Annual Testing Event
		TAPs and HAPs	Summa Canisters, EPA TO-14	Annual Testing Event
		O_2	EPA M3A	Annual Testing Event
		CO_2	EPA M3A	Annual Testing Event
		CO	EPA M10	Annual Testing Event
		NMHC (does this include methane? If not we should do methane too)		Annual Testing Event
Water (raw) City potable (C2) water	Water	pH	pH probe, ASTM D1293	Annual Testing Event
		Metals	EPA 200.8	Annual Testing Event
		Hardness		Annual Testing Event
Wastewater/softener regeneration water (from water treatment system)	Water	Temp	Thermocouple	Annual Testing Event

Location	Type of Sample	Analyte	Analytical Procedure	Frequency of Sampling
		pH	pH probe, ASTM D1293	Annual Testing Event
		Metals	EPA 200.8	Annual Testing Event
		Total Sulfide	ASTM D4658	Annual Testing Event
	Water	Metals		Annual Testing Event
		pH		Annual Testing Event
		Hardness		Annual Testing Event
		TDS		Annual Testing Event
Cooling water (from digester gas aftercooler)	Water	pH	pH probe, ASTM D1293	Annual Testing Event
		Metals	EPA 200.8	Annual Testing Event
		Hydrocarbon s		
		Total Sulfide	ASTM D4658	Annual Testing Event
Compressor cooling water (C3)	Water	pH	pH probe, ASTM D1293	Annual Testing Event
		Metals	EPA 200.8	Annual Testing Event
		Fats, Oils and Grease		Annual Testing Event
		TSS		
Condensate (from Sulfatreat)	Water	FOG (Fats, Oils and Grease)	EPA 413.2	Annual Testing Event
		Chloride	ASTM D5904	Annual Testing

Location	Type of Sample	Analyte	Analytical Procedure	Frequency of Sampling
				Event
		pH	pH probe, ASTM D1293	Annual Testing Event
		Hydrocarbons		
		Total sulfide	ASTM D4658	Annual Testing Event
Sulfur absorbents (from Sulfatreat)	Portion of absorbent may be recoverable	Hazardous or non-hazardous waste disposal will be determined at time of disposal.		Upon disposal (every 27 weeks)
Fuel Cell stack	Stack will be recycled by Fuel Cell Energy			Upon disposal
Deactivated catalysts (from preconverter, oxidizer, cathode exhaust and exhaust gas polisher)	Solid waste	Hazardous or non-hazardous waste disposal will be determined at time of disposal.		

[1] Digester gas = LSG/ADG = low pressure sludge gas = anaerobic digester gas

Performance Goals and Metrics

Project goals have been established to measure the performance of the fuel cell. For each goal, a metric was established. The metric will determine whether or not the goal was achieved. The goals and metrics are shown in the Table 2 below. The methods of recording data to quantify each performance goal are described below the table.

Table 2 – Performance Goals and Metrics

Performance Goal	Metric
1. Deliver high quality and quantity gas to the fuel cell	Acceptable gas supply >95% of the time. Digester gas BTU content between 550 and 610 Btu/scf @ 4 to 7 in w.c.; 50 to 100°F
2. Produce energy as designed on natural gas and digester gas	Produce 15,000 MWh gross power for 2-year test period. Prorate to later half of test after plant normalized after first 6-9 months. 1 MW gross. Parasitic electric loads for natural gas and digester gas to be measured during testing. Full power = 100 scfm gas
3. Produce minimal noise and equipment interferences	60 dBA at a distance of 100 feet from fuel cell pad (70 dBA at a distance of 10 feet)
4. Produce energy at a minimal cost	0.2 full time equivalents (FTEs) – Operations 0.2 FTEs – Maintenance 0.1 FTEs – Miscellaneous Cost of energy to produce 1 kWh of power < $0.10 (energy off the grid $0.05, but a premium is paid for green power)
5. Produce minimal air emissions – natural gas and digester gas (LSG/ADG[1])	CO < 10 ppmV NOx < 0.03 ppmV SOx < 0.01 ppmV NMHC < 10 ppmV
6. Produce wastewater/drain water with no adverse impacts to the treatment plant	Water treatment system brine Cooling water Condensate
7. Operate fuel cell on a continuous basis	Downtime for maintenance and troubleshooting limited to 20 hours/week (remain at hot standby condition) Availability of > 80% Run 85% of the time at full net power for 2 years. Determine frequency of downtime and length of time out of service
8. Operate fuel cell efficiently	49.0% on natural gas (South Plant scrubbed

Performance Goal	Metric
	digester gas) 49.0% on (Fuel Cell scrubbed digester gas)
9. Manage system with ease remotely	Monitor and control system through SCADA at the operations building at FCE's office in Danbury, CT
10. Remove hydrogen sulfide effectively from digester gas	Remove hydrogen sulfide to < 10 ppmV on inlet gas
11. Reasonable costs to dispose of solid waste	SulfaTreat system lasts for 0.6 years before replacement Carbon systems (both natural gas and digester gas systems) last for 0.3 years before replacement Fuel cell lasts for 3 years before replacement Preconverter catalyst lasts for 5 years before replacement Oxidizer catalyst lasts for 5 years before replacement Exhaust gas polisher lasts for 5 years before replacement Deoxidizer catalyst lasts for 5 years before replacement Fuel cell not negatively affected by digester gas Deactivated catalysts (from preconverter, oxidizer, deoxidizer and exhaust gas polisher) @ $/yr for disposal (recover precious metals) Fuel cell stack @ $/yr for disposal Desulfizer (Sulfatreat) @ $/yr for disposal Digester gas polisher) @ $/yr for disposal
12. Recover heat successfully	Recover 1.4MM Btu /hr of heat (13,800 lbs gas/hr) 650°F out of stack
13. Achieve output turndown	25% to 100%
14. Achieve output ramp rate	0.5 kW/min (cold start)
15. Meet design service life	10,000 hours (1.15 years)
16. Able to restart from a trip	Trip recovery to back on load in approximately 10 hours
17. Able to quickly start	Hot start in 10 hours (standby to rated output)

[1] Digester gas = LSG =ADG = Low pressure sludge gas = anaerobic digester gas

Data Recording for Performance Goals

Various areas of the fuel cell operation will be monitored throughout the two-year demonstration period to show how the fuel cell performance compares to the performance goals. That data collected will be analyzed to help determine the success of the project and feasibility for future similar installations. The data will be reviewed periodically throughout the demonstration period so that the testing program can be altered and enhanced.

Goal #1 – Deliver High Quality and Quantity Gas to the Fuel Cell

- Gas flow – continuous, by FCE meter, FE-800 for ADG, FE-117 for NG to Fuel Cell, FC-208 NG to AGO
- Gas Temperature – weekly reading, by CH, at gas inlet
- BTU content (from %CH4)– continuous, by FCE, AI-100
- H_2S – quarterly, by CH, before & after SulfaTreat beds with Jerome analyzer
- CH_4 – continuous, by FCE, AI-100
- CO_2 – estimate from CH_4%
- O_2 – continuous, by FCE, AI-100
- Record flows and hours of operation on Natural Gas and Digester Gas – continuous logging, by FCE
- Record all KC power outages – *continuous, by FCE, logbook*
- Record all gas issues – *continuous, by FCE, logbook*

Goal #2 – Produce Energy as Designed on Natural and Digester Gas

- Total Net AC Power – *continuous logging, by FCE*
- Total kW-hrs – *continuous logging, by FCE, on EBOP*
- <u>Efficiency</u>
  +Net AC Power out – *continuous logging, by FCE*
  +KC HRU BTU recovered – *future, by KC*
  /BTU gas in (from %CH4)– *continuous, by FCE, AI-100*
- <u>Parasitic Loads</u>
  -Transformer loads (EBOP) – *continuous, by FCE*
  - BOP loads (Plant loads) – *continuous, by FCE*

Goal #3 – Produce Minimal Noise and No Equipment Interference

- Decibel Meter – quarterly, by CH, at specified distance (can borrow meter from FCE)
- AM/FM radio reception (inverter interruption) – quarterly, by CH, at specified distance (likely a non-issue)

Goal #4 – Produce Energy at a Minimal Cost

- Record of all hours logged on Fuel Cell by KC and FCE – continuous logging, by KC and FCE
- Track all spare parts, equipment maintenance and other miscellaneous materials used

Goal #5 – Produce Minimal Emissions

- CO – annual service testing, by CH (sub TRC), at emission stacks

- NO_x - annual service testing, by CH (sub TRC), at emission stacks-
- SO_x - annual service testing, by CH (sub TRC), at emission stacks
- NMOC - annual service testing, by CH (sub TRC), at emission stacks

Goal #6 – Produce Wastewater and Drain Water that have no Adverse Impacts at the Treatment Plant

- Metals (Pb, Cu, Zn, etc) – semi-annually, by CH, at drain header and Water Treatment System discharge
- Hardness – semi-annually, by CH, at drain header and Water Treatment System discharge
- TDS – semi-annually, by CH, at drain header and Water Treatment System discharge

Goal #7 – Operate Fuel Cell on a Continuous Basis

- Record restart time from hot standby- quarterly, by CH request to FCE
- Record total hours of fuel cell operation – continuous logging, by FCE, hot hour timer on overview screen

Goal #8 - Operate Fuel Cell Efficiently

- Calculate net efficiency using power produce less parasitic loads and inverter losses.

Goal #9 - Manage System with Ease Remotely

- Monitor and control system through SCADA at the operations building at FCE's office in Danbury, CT

Goal #10 - Remove hydrogen sulfide effectively from digester gas

- Collect the gas in Tedlar bags and test the digester gas before and after the Sulfatreat and carbon using a handheld Jerome analyzer.

Goal #11 – Reasonable Costs to Dispose of Solid Waste

- Track frequency and cost for disposal of solids wastes from the fuel cell.
- Record life of all carbon beds – *at termination, by KC or FCE*
- Record all disposal costs – *at termination, by KC*
- Record deltaT across pre-converter – *hourly, by FCE, at pre-converter*
- Record deltaT across superheater – *hourly, by FCE, at superheater*
- Record deltaT across anode – *hourly, by FCE*
- Record deltaT across cathode – *hourly, by FCE*
- Record deltaT across KC HRU – *future, by KC, at HRU*

Goal #12 - Recover Heat Successfully

- Track heat recovered through the heat recovery unit and boiler.

Goal #13 – Achieve Output Turndown

- Measure decrease in power production and gas flow to the unit is turned down.
- Record output turndown (0% to 100%) – *quarterly, by CH request to FCE*

Goal #14 – Achieve Output Ramp Rate

- Record ramp rate and correlate it with predicted ramp rate.
- Record output ramp rate - *quarterly, by CH request to FCE*

Goal #15 – Meet Design Service Life

- Record service life and compare to design service life.

Goal #16 – Ability to Restart from a Trip

- Record Plant Full Power Trips – *continuous by, by FCE*
- Record # hours in hot standby - *quarterly, by FCE*
- Record time that it takes to get back up to full power from a trip and compare to design criteria.

Goal #17 – Ability to Quickly Start

- Record time it takes to get up to full power from start and compare to design criteria.
- Record number of fuel cell cycles – by FCE

Appendix C
FuelCell Energy Training and Maintenance Manual Summary

FuelCell Energy

DFC®1500 Intermediate Training

FuelCell Energy

DFC®1500 Intermediate Training

Contents:

1. MW0001 – P&ID and Layout Drawings
2. MW002/MW003 – DFC® 1500 Systems Overview
3. MW004 – Digester Gas Conditioning
4. MW005 – Fuel Preparation
5. MW006 – Nitrogen Gas Supply
6. MW007 – Heat Recovery
7. MW008 – Anode Gas Oxidizer
8. MW009 – Water Treatment System
9. MW010 – Instrument Air System
10. MW011 – Electrical Distribution
11. MW012 – Startup System
12. MW013 – Fire Alarm and Detection System
13. MW014 – Gas Chromatography
14. MW015 – Anode Cover Gas System
15. MW016 – Distributed Control System and Plant Operations
16. Plant Settings and Procedures
17. System Drawings

FuelCell Energy

DFC 1500

Operations/Maintenance Manual

VOLUME III - MAINTENANCE

11/15/2005

Document Number:4149
REVISION: C

LIST OF EFFECTIVE PAGES

NOTE: All pages are fleet-wide, except as noted with a suffix "(XYZ)", where XYZ = your Unit Number. As applicable, supersede fleet pages in your manual with Unit-specific pages. If not already known, contact your FuelCell Energy representative for your Unit Number.

Procedure	Rev	DATE
Section 1		
1.1	B	04/18/05
1.2	B	04/18/05
1.3	B	04/18/05
Section 2		
2.1	B	04/18/05
2.2	C	11/15/05
Section 3		
3.1	B	04/18/05
3.2	B	04/18/05
3.3	B	04/18/05
3.4	B	04/18/05
3.5	C	11/15/05
3.6	B	04/18/05
3.7	B	04/18/05
3.8	B	04/18/05
3.9	B	04/18/05
3.10	B	04/18/05
3.11	B	04/18/05
3.12	B	04/18/05
3.13	B	04/18/05
3.14	B	04/18/05
3.15	B	04/18/05
3.16	B	04/18/05
3.17	B	04/18/05
Section 4		
4.1	C	Deleted
4.2	B	04/18/05
4.3	C	11/15/05
4.4	C	11/15/05
4.5	B	04/18/05
4.6	B	04/18/05

Procedure	Rev	DATE
4.7	C	11/15/05
4.8	B	04/18/05
4.9	B	04/18/05
4.10	B	04/18/05
4.11	B	04/18/05
Section 5		
5.1	B	04/18/05
5.2	B	04/18/05
5.3	B	04/18/05
5.4	B	04/18/05
5.5	B	04/18/05
5.6	B	04/18/05
5.7	B	04/18/05
5.8	B	04/18/05
5.9	B	04/18/05
5.10	B	04/18/05
5.11	B	04/18/05
5.12	B	04/18/05
Section 6		
6.1	B	04/18/05
6.2	B	04/18/05
6.3	B	04/18/05
6.4	B	04/18/05
Section 7		
7.1	B	04/18/05
7.2	B	04/18/05
7.3	B	04/18/05
7.4	B	04/18/05
7.5	C	11/15/05
7.6	C	11/15/05
Section 8		
8.1	C	11/15/05

Procedure	Rev	DATE
8.2	B	04/18/05
8.3	B	04/18/05
Section 9		
9.1	B	04/18/05
9.2	C	11/15/05
9.3	C	11/15/05
9.4	B	04/18/05
9.5	C	11/15/05
9.6	B	04/18/05
Section 10		
10.1	B	04/18/05
10.2	B	04/18/05
10.3	B	04/18/05
Section 11		
11.1	B	04/18/05
11.2	B	04/18/05
11.3	B	04/18/05
11.4	B	04/18/05
Section 12		
12.1	B	04/18/05
12.2	B	04/18/05
12.3	B	04/18/05
12.4	B	04/18/05
12.5	B	04/18/05
12.6	B	04/18/05
12.7	B	04/18/05
12.8	C	11/15/05
12.9	C	11/15/05
Section 13 (TBD)		
13.1	B	04/18/05
Section 14		
14.1	B	04/18/05

Procedure	Rev	DATE
14.2	B	04/18/05
14.3	B	04/18/05
14.4	B	04/18/05
14.5	B	04/18/05
14.6	B	04/18/05
14.7	B	04/18/05
14.8	B	04/18/05
14.9	B	04/18/05
14.10	B	04/18/05

TABLE OF CONTENTS

VOL. III MAINTENANCE

SECTION 1 INTRODUCTION

1.1 About This Manual

1.2 DFC1500 Power Plant Description

1.3 Maintenance Timeline (Insert 3ea 11x17 pages)

SECTION 2 GENERAL MAINTENANCE

2.1 Safety Precautions

2.2 Quarterly Inspection Rounds/Logs

SECTION 3 WATER TREATMENT SYSTEM

3.1 Activated Carbon Filter Water Sampling

3.2 Activated Carbon Filter Control Valve (XV-402) Lubrication

3.3 Activated Carbon Filter Media Replacement and Control Valve (XV-402) O-ring Replacement

3.4 Multimedia Filter Control Valve (XV-404) Lubrication

3.5 Multimedia Filter Media Replacement and Control Valve (XV-404) O-ring Replacement

3.6 Water Softeners Water Sampling

3.7 Water Softener Replacement and Control Valve (XV-406) O-ring Replacement

3.8 Brine Tank Salt Replenishment

3.9 Antiscalant Tank Solution Replenishment

3.10 Reverse Osmosis (RO) Prefilter (FL-3, FL-4, FL-5) Element Replacement

3.11 Reverse Osmosis Membrane Replacement

3.12 Continuous De-Ionization (CDI) System

3.13 Mixed Bed Filter Bottle (SDI) Rotation and Replacement

3.14 Final Polishing Filter (FL-6) Element Replacement

3.15 Pump Motor Bearing Lubrication

3.16 Product Water Storage Tank Vent Filter (FL-7) Element Replacement

3.17 WTS PLC Battery replacement

****Continued on next page****

TABLE OF CONTENTS (CONTINUED)

SECTION 4 FUEL PREPARATION SYSTEM

4.1 DELETED

4.2 Desulfurizer Sampling, Quarterly, Lab Analysis

4.3 Desulfurizer Carbon Bed Replacement

4.4 Desulfurizer Afterfilter Element Replacement

4.5 Natural Gas Flowmeter Zero Point Calibration Check

4.6 Deoxidizer Catalyst Replacement

4.7 Preconverter Catalyst Replacement

4.8 UV/IR Detector maintenance

4.9 AT-110/342A&B LEL Detectors maintenance/calibration

4.10 LEL Detectors (Standalone) Calibration

4.11 Desulfurizer Sampling, Monthly, Drager Tube

SECTION 5 INSTRUMENT AIR SYSTEM

5.1 Intake Air Filter Element Replacement

5.2 Air Compressor Cleaning

5.3 Air Compressor Intercooler Cleaning

5.4 Air Compressor V-Belts Inspection and Replacement

5.5 Air Compressor Emergency Stop Test

5.6 Air Compressor Safety Valve Testing

5.7 Air Compressor Bearing Lubrication

5.8 Dryer Inlet Air Moisture Seperator (PD) Element Replacement

5.9 Air Dryer Desiccant Replacement/Inspection

5.10 Dryer Outlet Air Filter (DD) Element Replacement

5.11 Automatic Drain Valve Cleaning

5.12 IA Components Service Swapping

5.12.2 Air Dryer tower service switching

5.12.3 Compressor tower service switching

****Continued on next page****

TABLE OF CONTENTS (CONTINUED)

SECTION 6 COMPRESSED GAS SYSTEM
- 6.1 Nitrogen System In-Line Filters
- 6.2 AT-100 Gas Analyzer Calibration Gas Bottle Changeout
- 6.3 Anode Cover Gas Bottle Changeout
- 6.4 Nitrogen 6-pack replacement

SECTION 7 ANODE GAS OXIDIZER (AGO) SYSTEM
- 7.1 AGO Catalyst Replacement
- 7.2 AGO Blower Bearing and Shaft Lubrication
- 7.3 AGO Air Intake Filter Replacement
- 7.4 AGO Blower VFD, A/C Unit & Heater Clean and Inspect
- 7.5 AGO BMS Panel, Circulating Fan and Heater Clean and Inspect
- 7.6 AGO BMS PLC Battery replacement

SECTION 8 HEAT RECOVERY UNIT (HRU)
- 8.1 HRU Polisher Catalyst Replacement
- 8.2 Thermal Imaging of HRU externals
- 8.3 Humidifier nozzle inspection/replacement

SECTION 9 ELECTRICAL CONTROL SYSTEM, ABB
- 9.1 EBOP Inspection ,Cleaning and Inverter Air Filter Replacement
- 9.2 PM 860 Battery Replacement
- 9.3 F60 Relay Battery Replacement
- 9.4 Thermal Imaging of EBOP components
- 9.5 UPS Battery Replacement
- 9.6 EBOP, A/C Unit & Heater Clean and Inspect

SECTION 10 HVAC SYSTEM
- 10.1 Compartment Exhaust Fans Cleaning and Inspection
- 10.2 Compartment Heaters Cleaning and Inspection
- 10.3 Air Purge Fans Flow Switch Calibration

****Continued on next page****

TABLE OF CONTENTS (CONTINUED)

SECTION 11 START-UP SKID
- 11.1 Start-Up Heater Inspection and Replacement
- 11.2 Start-Up Blower Shaft Rotation
- 11.3 Start-Up Blower Bearing Lubrication
- 11.4 Start-Up Blower drive belt inspection and adjustment

SECTION 12 SPECIAL PROCEDURES
- 12.1 Start-Up Skid Extended Storage and Preparation For Use
- 12.2 Explosion-Proof Lamp Replacement
- 12.3 Pressure Relief Valve Test and Calibration
- 12.4 Delta V Database Defragmentation
- 12.5 Delta V Database and Graphics Backup
- 12.6 Electrical panel enclosure inspections
- 12.7 Planned Power & Efficency De-rating of DFC1500 Module
- 12.8 Drager Handpump use and setup
- 12.9 CAT100 (AT-100) Analyzer BIOS Battery Replacement

SECTION 13 ELECTRICAL CONTROL SYSTEM, SATCON
- 13.1 EBOP Inspection ,Cleaning and Inverter Air Filter Replacement
- 13.2 PM 860 Battery Replacement
- 13.3 F60 Relay Battery Replacement
- 13.4 Thermal Imaging of EBOP components
- 13.5 UPS Battery Replacement
- 13.6 EBOP, A/C Unit & Heater Clean and Inspect
- 13.7 EBOP Rooftop Exhaust fans Clean and Inspect

SECTION 14 APPENDIX
- 14.1 Replacement Parts and Consumables
- 14.2 Tools and Equipment
- 14.3 Electrical Charts
  - 14.3.1 - Panel 600-LP-D Layouts
  - 14.3.2 - Panel 600-LP-A Layouts

****Continued on next page****

TABLE OF CONTENTS (CONTINUED)

14.3.3 - Panel 600-LP-B Layouts

14.4 Periodic Inspection Checklists

Quarterly Inspection Logs

14.4.4 – SK1-001 Periodic Inspection Checklist

14.4.5 – SK2-001 (AGO Skid) ,ABB EBOP and Start-Up Skid Periodic Inspection

14.5 Torque Guide

14.5.1– DFC1500 Engineered Components Torque Listing

14.5.2 – FCE Piping Specification FCE-SP-50-3 (Insert)

14.6 Glossary of Acronyms

14.7 Index

14.8 List of Figures

14.9 Sample specifications and & Testing

14.9.1 – Water Sample specifications and information

14.9.2 – Gas Sample specifications and information

14.9.3 - Spent Carbon Recyclers

14.10 FCE Approves Gas Analysis Labs

ABOUT THIS MANUAL

This manual provides reference material to trained maintenance personnel. Included in this manual is a description of **when** maintenance is required for **what** part/equipment, **where** the part/equipment is located, and **how** the maintenance is to be performed.

ORGANIZATION The Maintenance Manual is divided into 14 major sections:

Section 1 (Introduction) - Provides educational and reference data needed to understand the operating and maintenance scheduling requirements of the power plant.

Section 2 (General Maintenance) - Provides safety and procedural instructions related to inspecting and maintaining consumables and components.

Sections 3 through 11 - Provides safety precautions and procedural instructions related to the scheduled inspection and maintenance of components found within the following power plant systems:

Section 3	Water Treatment System
Section 4	Fuel Preparation System
Section 5	Instrument Air System
Section 6	Compressed Gas System
Section 7	Anode Gas Oxidizer (AGO) System
Section 8	Heat Recovery Unit (HRU)
Section 9	Electrical Control System(ABB)
Section 10	HVAC System
Section 11	Start-Up Skid

Section 12 (Special Procedures) - Provides safety precautions and procedures needed to respond to conditions not covered under scheduled maintenance.

Section 13 Electrical Control System (Satcon)

Section 14 (Appendix) - Provides detailed listings and charts used with the maintenance procedures.

ABOUT THIS MANUAL (CONTINUED)

HOW TO USE THIS MANUAL

If you need to know **what** part or equipment needs maintenance for a specific time period, see *Maintenance Schedule* starting on page 1.3.1.

If you need to know **how** to maintain a specific part or equipment, find the appropriate page describing the procedure for the specific part or equipment in the *Index*. See Section 14.11.

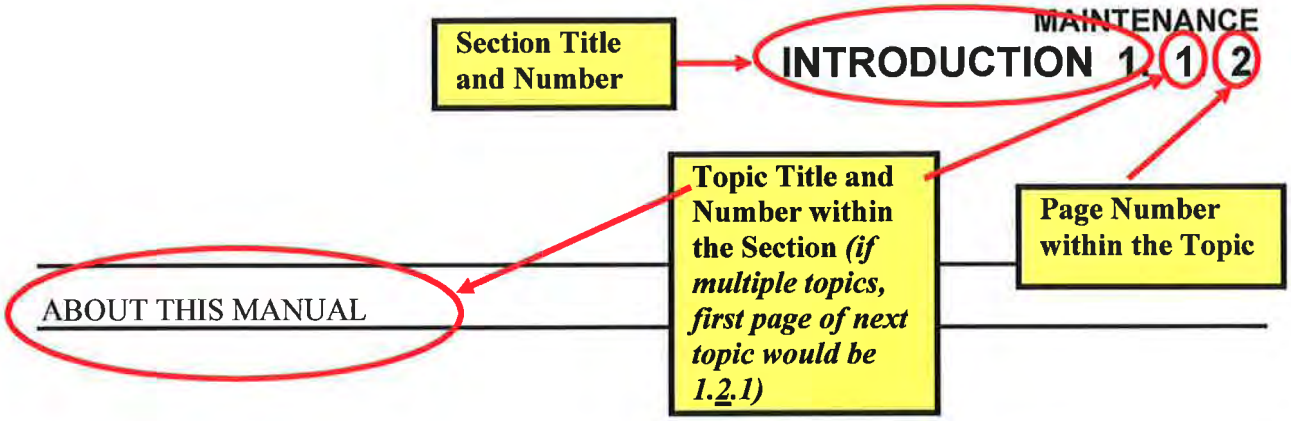
For information on **replacement parts** not listed in this document, refer to FCE's spare part *Bill of Materials* (BOM) for specific part number information.

Location Diagrams show general equipment locations. Refer to the Plot Plan for exact information on **equipment location, configuration, and identification**.

> **Note:** While every attempt was made to ensure the content of this manual was accurate at the time of its publication, design and manufacturing changes may impact the tag numbers used to identify the location of the parts. The reader should verify any such references with the most current *Piping and Instrumentation Diagrams and Arrangement Drawings*.

NUMBERING SYSTEM

Each page is assigned a number reflecting the Section, the Topic, and the Page Number within the topic. **Example:**



ABOUT THIS MANUAL (CONTINUED)

WARNING AND CAUTION NOTES

The following boxed notes are used throughout this manual to make you aware of risks related to maintaining the power plant:

WARNING

This indicates a condition or a procedure which, if not followed, could result in injury or loss of life.

WARNING

This indicates an electrical hazard or a procedure which, if not followed, could result in injury or loss of life.

WARNING

This indicates a hot surface hazard or a procedure which, if not followed, could result in severe burns.

CAUTION

This indicates a condition or a procedure which, if not followed, could damage the equipment or system.

Appendix D
King County South Treatment Plant
Fuel Cell Operations Manual
(September 2004)

Fuel Cell

Operations Manual

September 2004

90% DRAFT

PROPRIETARY INFORMATION,
do not copy or release information from this volume
without the permission of FuelCell Energy, Inc.

King County

Department of Natural Resources and Parks
Wastewater Treatment Division
201 South Jackson
Seattle, Washington 98104

Publication #1346

Produced by Technical Publications with FuelCell Energy, Inc.
206-684-2493
Mail stop KSC-NR-0514

Preface

This manual is intended to be a reference for operators. The manual is intended to function as a foundation for a structured operator training program. This manual also meets Washington State Department of Ecology requirements that all King County Wastewater Treatment Division (WTD) facilities have current operations manuals, and OSHA process safety management requirements for systems that use methane.

The purpose of the manual

This manual is intended to provide the following:

- Descriptions of the fuel cell system and its components including the digester gas preparations system; which includes physical and function descriptions, control strategies, control options, and alarm/troubleshooting information.
- Operating procedures
- Routine service checklists

How the manual is designed

This manual is intended to be used with Fuel Cell Energy's on-line and classroom training program, and their overview and preventive maintenance manuals.

This is a modular, graphics-based manual. That means that each section of the manual is composed of modules. These are self-contained units of information presented on two or four page spreads. Each module discusses a single topic and includes all related tables, illustrations, and explanations. Each module is also developed as an "info-graphic," combining text and illustrations to identify system components and explain their function.

Who should use this manual

This manual is designed to be used by WTD operations and maintenance, process, capital improvement staff, and contractors.

How the manual is organized

This manual is organized into overview, physical and functional descriptions, control strategies, and operating procedures for each system and subsystem at the pump station.

For further information

- There is a complete set of drawing and vendor information located in a bookcase inside the door of the trailer located accross the road from the fuel cell system.

Notes, cautions, and dangers

Notes, cautions, and dangers are used throughout this manual to give you critical information .

NOTE: *A note points out essential information concerning an operating procedure or a condition. Notes can come before or after the procedure or condition to which they apply.*

CAUTION

A caution identifies a practice or procedure that, if not strictly observed, could result in damage or destruction of equipment. Cautions always come before the practice or procedure to which they apply.

DANGER

A danger identifies a practice or procedure that, if not followed correctly, could result in personal injury or loss of life. Dangers always come before the practice or procedure to which they apply

Future revisions

A manual such as this is never complete. It must be regularly updated to reflect changes in systems, equipment, and tasks so that it continues to meet your needs. As you read the manual, you will undoubtedly discover incorrect, outdated, or missing information. Please help us identify this information by contacting us at one of the numbers listed below.

As this manual is finalized, it will be 3-ring bound and tabbed for easy reference.

Documentation contacts

For information on this documentation please call

- Barb Johnson, 206-684-2493:
- Brian Thompson, 206-263-5424
- Naomi Yura, 206-684-1715

Table of Contents

Preface **i-3**

The purpose of the manual
How the manual is designed
Who should use this manual
How the manual is organized
For further information
Notes, cautions, and dangers
Future revisions
Documentation contacts

• **Table of Contents** **i-5**

1 Introduction to the Fuel Cell Systems **1-1**

1.1 How Fuel Cells Work 1-2

Electricity through oxidation and reduction

1.2 How Our Fuel Cell Works 1-4

History of MCFCs
FuelCell Energy's fuel cell
Natural gas vs. digester gas

1.3 Overview of the Fuel Cell System 1-6

Portable startup heater and blower
Fuel gas preparation system
Anode gas oxidizer — oxidant supply system
Heat recovery system
Fuel cell stack module

1.4 Overview of the Electrical Conditioning and the Support Systems 1-8

Electrical equipment
Digester gas preparation system
Nitrogen purging system
Anode cover gas system
Instrument air
Calibration gas
Water treatment system booster pumps

1.5 Overview of the Water Treatment System 1-10

Pretreatment system
Reverse osmosis unit
Deionization system

1.6 How the Fuel Cell Is Controlled 1-12

The FCE operator's role
Control system
Control system responses

1.7 Using the Operator Interface Units 1-14

Common buttons
Navigating
Acknowledging alarms
Operating the DCS (DeltaV) computer
Shutting down the Delta V computer
Operating the Fire Alarm Panel

1.8 Handling the Effluent Streams 1-18

Continuous effluent streams
Intermittent waste

1.9 Location and Layout of the Fuel Cell System 1-20

Emergency shutdown buttons
Lower explosive limit meter locations
Freeze protection
Layout

1.10 Layout of Skid 1, 2, and EBOP 1-22

The EBOP skid
Skid 2, AGO skid
Skid 1
Startup skid
Digester gas skid

1.11 Layout of the Digester Gas Preparations System 1-24

Emergency monitoring
Equipment

2 Checking the Fuel Cell 2-1

2.1 Checking the Fuel Cell System 2-2

Safety
Electrical classification
King County responsibilities
General safety
Confined spaces
Hot work

2.2 Checking Skid 1, Water Treatment and Fuel Preparation 2-4

General daily checks for skid 1
Checking the fuel preparation area
Finishing the water treatment area
Weekly

2.3 Checking Skid 2, the AGO Skid and the Startup Skid 2-10

Checking side A
Checking side B
Checking side C
Checking the start-up skid

2.4 Checking the Electrical Balance of Plant and Fuel Cell Stack Module 2-14

2.5 Checking the Digester Gas Preparation Skid 2-16

2.6 Checking the Fuel Cell System Quarterly 2-18

3 Safety 3-1

3.1 Fuel Cell Safety Considerations 3-2

Safety
Electrical classification
King County responsibilities
General safety
Confined spaces
Hot work

3.2 Emergency Shutdown and Alarm Beacon Locations 3-4

4 Alarms 4-1

4.1 Fuel Cell System Process Halts 4-2

Heatup ramp hold
Heatup 1 halts
Heatup 2 through 4 halts
Reduced kW ramp down
Hot standby step down
Emergency shutdowns, fire and gas alarms

4.2 Fuel Cell System Shutdowns 4-4

Shutdown with power available
Shutdown with no power available, DCS on UPS
Plant shutdown due to computer failure
Manual plant shutdown
Resetting trips

4.3 Fuel Cell Alarms 4-6

Alarms with multiple set points and responses

4.4 Local System Alarms 4-16

5 Fuel Cell System Control 5-1

5.1 Overview of the Fuel Cell System Controls 5-2

Plant heatup and cooldown
Plant emergency shutdown and restart
Operator responsibilities on shutdown
Power outage

5.2 How the Fuel Cell Works 5-4

Control strategy
Control options
Interlocks
Alarms
Power outage

5.3 How the Support Systems Work 5-8

Control strategy
Control options
Alarms
Power outage

5.4 Overview of the Fuel Cell Startup Skid Controls 5-10

Components
Control strategy
Control options
Alarms
Power outage

5.5 Overview of the Anode Fuel Preparation System Controls 5-12

Gas supply and isolation
Fuel gas preparation system
Anode fuel gas supply

5.6 Overview of the Oxidant Supply System Controls 5-14

Components
Control strategy
Cathode exhaust system

5.7 Overview of the Fuel Cell Stack Module Controls 5-16

Fuel cell stack controls
Control strategy
Monitoring fuel distribution

5.8 Overview of the Electrical Conditioning System Controls 5-18

Monitoring
Control options
Calculated set points
Power outage

5.9 Overview of the Instrument Air, Fire Alarm Panel, and Nitrogen Supply Controls... 5-20

Instrument air system
Fire alarm system
Nitrogen gas supply system

5.10 Overview of the Water Treatment System Controls..... 5-22

Enclosure
Pretreatment
Reverse osmosis
Deionization
Storage and transfer
Alarms
Power outage

5.11 Overview of the Digester Gas Conditioning Controls..... 5-26

Compressor enclosure
Raw digester gas supply
Feed knockout drum
Digester gas compressor
Aftercooler
Discharge knockout drum
High efficiency oil filter
SulfaTreat
Digester gas polisher

5.12 Enabling the Fuel Cell System for Startup..... 5-30

Startup skid
Enabling the fuel cell system for startup
Enabling process and utility feed streams

5.13 Heating Up the Fuel Cell Stack 5-32

Heatup 1
Heatup 2
Heatup 3
Heatup 4
Hot standby
Power generation
Transition from load reduction back to hot standby

5.14 Normal Fuel Cell Shutdown 5-34

Cooldown from hot standby
Normal shutdown

5.15 Trip Recovery, Rapid Restart, and Hot Restart 5-36

Hot restart
Rapid restart

6 Operating the Fuel Cell 6-1

6.1 Operators Notes—Normal Operation 6-2

In General
Heatup 1:
Hot Restart:
Heatup 2, Rapid Restart not selected
Monitor the following during heat up
Heatup 3
Heatup 4
Hot Standby
Power Generation

6.2 Operators Notes—Trip Recovery 6-6

When responding to a plant emergency shutdown (ESD):
Rapid Restart
Three ways the plant can respond

6.3 Operators Notes— the Anode Cover Gas System and Nitrogen Purge 6-10

Anode cover gas
Nitrogen purge systems

6.4 Operators Notes—Monitoring Cell Group Voltage Deviation 6-12

Cell voltage
How to monitor the dV/cell

6.5 KCPP Startup to Hot Standby (NG) 6-14

Assessing the plant system
Changing from SHUTDOWN to IDLE
Changing from IDLE to HEATUP-1
Changing from HEATUP-1 or HOT RESTART to HEATUP-2(NG)
Changing from HEATUP-2 NG to HEATUP-3 NG
Changing from HEATUP-3 NG to HEATUP-4 NG
Changing from HEATUP-4 NG to HOT STANDBY NG
Startup to Hot Standby plant settings

6.6 Startup to Hot Standby DG 6-24

Assessing the plant system
Changing from SHUTDOWN to IDLE
Changing from IDLE to HEATUP-1
Changing from HEATUP-1 or HOT RESTART to HEATUP-2(DG)
Changing from HEATUP-2 DG to HEATUP-3 DG
Changing from HEATUP-3 DG to HEATUP-4 DG
Changing from HEATUP-4 DG to HOT STANDBY DG
Startup to Hot standby plant settings

6.7 KCPP Power Generation 6-34

Initial conditions
Changing from HOT STANDBY to Grid Power Generation
Operating in Power Generation (grid power only)
Changing power level in Power Generation (grid power only)
Responding to a reduce power trip in Power Generation (grid power only)
Responding to a Trip to Hot Standby in Power Generation (grid power only)
Changing from Grid Power Generation to Hot Standby

6.8 KCPP Trip Recovery Procedure 6-42

Trip recovery
Preparing to restart after an ESD
Changing from SHUTDOWN to IDLE
Required screen prints table

6.9 KCPP Hot Restart Procedure 6-46

Initial conditions
Prepare for Hot Restart
Shifting the plant to Hot Restart
Startup to Hot standby plant settings

6.10 Rapid Restart Procedure 6-48

Initial conditions
Potential problems
Rapid Restart
Rapid Restart with anode cover gas
Rapid Restart without anode cover gas

6.11 KCPP Shutdown Procedure 6-54

Plant shutdown
Cooling down from Hot Standby /Heatup-4 to Cooldown 1 NG/DG
Cooling down from Cooldown-1or from Heatup-3 to Cooldown-2
Cooling down from Cooldown-2 or Heatup-2 to Cooldown-3
KCPP cool down below 286°F

6.12 Using the Startup Skid 6-60

Starting up the startup skid
Shutting down the startup skid

6.13 Operating the Fuel Preparation System 6-62

Before starting the fuel prep system
Starting the system
Shutting down the system
Purging the desulfurizers with nitrogen

6.14 Changing Desulfurizer Lead and Guard Positions 6-66

Changing the lead/guard position
Running with one desulfurizer online
Putting a desulfurizer back in service

6.15 Purging the Desulfurizer and Preconverter with Nitrogen 6-70

Purging desulfurizer A with nitrogen
Purging desulfurizer B with nitrogen
Purging both desulfurizers with nitrogen
Purging the preconverter with nitrogen

6.16 Replacing the Filter Media on the Fuel Preparation System 6-74

Replacing the carbon media in the desulfurizer
Replacing the filter on the desulfurizer afterfilter (100-fl-102)
Replacing the filter on the preconverter afterfilter (100-FL-102)
Sulfur analysis sampling
Taking samples

6.17 Operating the Nitrogen System 6-78

Before starting the nitrogen the systems
Starting the slow purge system
Starting the rapid purge system
Changing the rapid purge six-pack
Changing the slow purge six-pack
Disconnecting the rapid purge six-pack
Disconnecting the slow purge six-pack

6.18 Operating the AGO System 6-82

Before starting the system
Starting the AGO system
Shutting down rapidly (an emergency)
Locking out and purging the natural gas desulfurized (NGD) to the AGO skid

6.19 Operating the Water Treatment System 6-84

Before starting the water treatment system
Starting the water treatment system
Shutting down the water treatment and distribution system
Restarting after a power loss
Checking the water treatment system (normal operation)

6.20 Operating the EBOP 6-88

Shutdown due to a general power failure (fuel cell NOT on line)
Before starting the electrical system
Starting the electrical system
Securing the electrical balance of plant (EBOP)
Securing the fuel cell electrical system (once the EBOP has been energized and the fuel cell has been producing power)
Restoring power following a power failure
Before starting the UPS
Starting the UPS
Testing the UPS
Shutting down the UPS
Testing the UPS on 120 V loads in 600-LP-B
Replacing the batteries

6.21 Miscellaneous Systems 6-94

Operating the DeltaV computer
Shutting down the Delta V computer
Operating the fire alarm panel
Operating the ventilation systems
Before starting the ventilation equipment
Starting up the ventilation equipment
Operating the drainage systems
Before starting the drainage system
Starting up drainage
Starting the instrument air system
Starting the digester gas conditioning system

6.22 Initial Valve Lineup Checklist 6-104

1 Index 1-1

A Appendix A-1

A.1 KCPP DFC1500-1 Plant pre-startup valve lineup A-3

A.2 KCPP DFC1500-1 ADG system startup, polisher A to B pre-startup valve lineup A-9

A.3 KCPP DFC1500-1 Instrument air system pre-startup valve lineup A-15

A.4 KCPP DFC1500-1 Water treatment system pre-startup valve lineup A-19

A.5 KCPP DFC1500-1 Nitrogen system pre-startup valve lineup A-21

B Acronyms and Glossary B-1

B.1 Acronyms and Glossary B-3

Acronyms
Glossary of terms

SECTION 1
Introduction to the Fuel Cell Systems

1.1 How Fuel Cells Work 1-2
1.2 How Our Fuel Cell Works 1-4
1.3 Overview of the Fuel Cell System 1-6
1.4 Overview of the Electrical Conditioning and the Support Systems 1-8
1.5 Overview of the Water Treatment System 1-10
1.6 How the Fuel Cell Is Controlled 1-12
1.7 Using the Operator Interface Units 1-14
1.8 Handling the Effluent Streams 1-16
1.9 Location and Layout of the Fuel Cell System 1-18
1.10 Layout of Skid 1, 2, and EBOP 1-20
1.11 Layout of the Digester Gas Preparations System 1-22

1.1 How Fuel Cells Work

Fuel cells, first conceived of in 1839, use hydrogen and oxygen to produce electricity. Fuel cells have a lot in common with electrochemical batteries. The main difference between them is that in a battery, the material to be converted into energy is part of the battery. In a fuel cell, the material to be converted into energy is separate from the unit that converts the fuel.

Think of a fuel cell as a system that borrows electrons from hydrogen, ships them off to do some useful work, and then grabs them back and pairs them with oxygen to form water. The chemical equation is: $2H_2 + O_2 = 2H_2O$.

Electricity through oxidation and reduction

How a fuel cell is made. Inside a fuel cell, hydrogen and oxygen gas are fed into two separate chambers divided by a porous membrane. An anode (negative conductor) is in the hydrogen chamber. A cathode (positive conductor) is in the oxygen chamber. Two chemical reactions, called oxidation and reduction, take place when the anode and cathode are connected.

The proton exchange membrane or polymer electrolyte membrane (PEM[1]) only allows electrolyte and the positively charged hydrogen ions to pass through it. This forces the negatively charged electrons to travel along an outside circuit to the cathode, creating an electrical current.

How the system runs. When hydrogen is fed into a fuel cell, a catalyst on the anode converts the gas into negatively charged electrons (e-) and positively charged ions (H+). The electrons flow through an outside circuit to the cathode. This process is called oxidation.

The hydrogen ions migrate through the membrane and the electrolyte to the cathode where they combine with oxygen and the electrons to produce water. This process is called reduction.

Each fuel cell produces only a small amount of voltage, so the fuel cells are arranged in “stacks” to provide enough power.

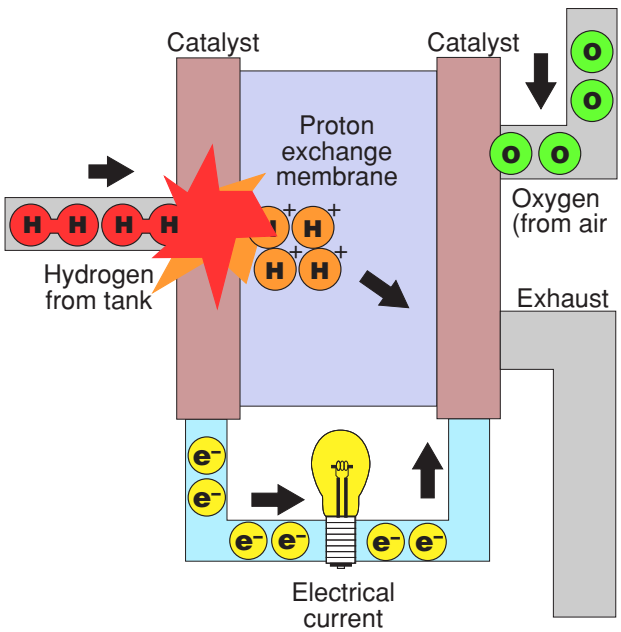
Advantages of using a fuel cell. A fuel cell is quiet, efficient, and clean. Fuel cells are about 50 percent efficient, while internal combustion engines are only 12 to 15 percent efficient.

Where the hydrogen comes from. Reformers produce hydrogen from hydrogen-rich fuels. Once they strip off the hydrogen molecules, the reformers leave heat, carbon dioxide, and carbon monoxide as by-products.

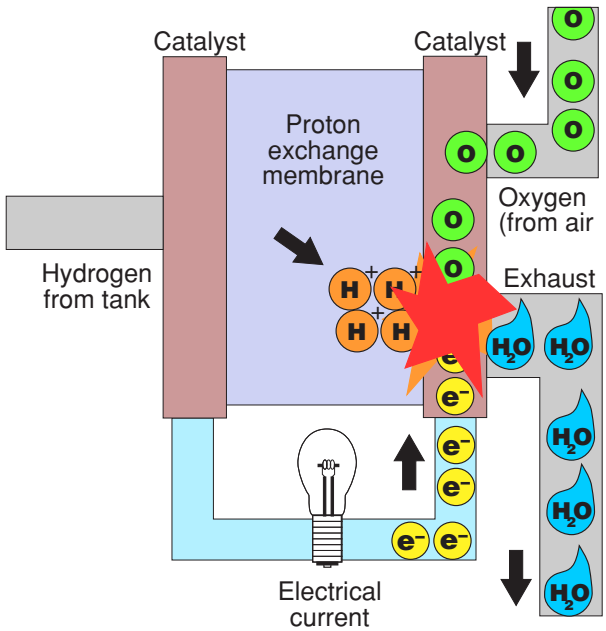
Illustration

Red H is a hydrogen molecule (H_2)
Orange H+ is a hydrogen ion after its electron is removed
Yellow e- is an electron moving through a circut
Green O is an oxygen molecule (O_2)
Blue drops are water

1. Different types of fuel cells are distinguished by the kind of membranes they use.



Oxidation



Reduction

Reference

1.2 How Our Fuel Cell Works

Our system uses a molten carbonate fuel cell (MCFC). MCFCs work somewhat differently from other fuel cells. In a molten carbonate fuel cell, the proton exchange membrane (PEM) is replaced by piece of ceramic soaked in an electrolyte of melted carbonate salt. The pores of the ceramic, filled with the electrolyte, conduct carbonate ions (CO3) from the cathode to the anode. At the anode, hydrogen reacts with the CO3 ions to produce water, carbon dioxide, and electrons. The electrons travel through an outside circuit, providing electrical power, then return to the cathode. At the cathode, oxygen and carbon dioxide react with these electrons to form CO3 ions. The C03 ions enter the electrolyte and transfer current through the fuel cell. So in a MCFC, the shuttle action of the carbonate ions, which also serve as an acidic electrolyte, makes the system run.

History of MCFCs

In the late 1950s, Dutch scientists G. H. J. Broers and J. A. A. Ketelaar began building on previous work done on MCFCs in the 1930s by Swiss scientists. Broers and Ketelaar focused on electrolytes of fused (molten) carbonate salts.

By 1960, they reported making a cell that ran for six months using an electrolyte mixture of lithium-, sodium- and/or potassium carbonate, impregnated in a porous sintered[1] disk of magnesium oxide. However, the molten electrolyte was slowly lost in the process. About the same time, Francis T. Bacon was working with a molten cell using two-layer electrodes on either side of a "free molten" electrolyte. At least two groups were also working with semisolid or "paste" electrolytes and other groups were researching "diffusion" electrodes.

How the fuel cell is constructed. The ceramic is made of made of lithium aluminum oxide. The electrolyte is lithium-potassium carbonate salts heated to about 1,200°F. At 1,200°F, the salts melt into a solution that can conduct ions between the two porous electrodes. The anode is a highly porous sintered nickel (Ni) powder. The cathode is porous nickel oxide doped[2] with lithium. This means the catalyst[3] for both chemical reactions is nickel.

How the system runs. Reformers produce hydrogen from hydrogen-rich fuels, in this case, methane. During reforming, methane is combined with steam, creating carbon monoxide (CO) and hydrogen (H_2).

The anode chemical reaction between hydrogen (H_2) and carbonate ions (CO_3—from the electrolyte) produces water (H_20) and carbon dioxide (CO_2) and releases electrons to the anode.

The cathode process combines oxygen (O_2) and carbon dioxide (CO_2) from the oxidant stream with electrons from the cathode to produce carbonate ions (CO_3) which enters the electrolyte.

The CO_2 in the oxidant stream is collected from the anode exhaust and mixed into the cathode feed stream to replenish the CO_2 in the electrolyte.

The chemical reactions are as follows:

$CH_4+H_20 \Leftrightarrow CO+3H_2$	Methane reforming reaction
$H_20+ CO \Leftrightarrow H_2 + CO_2$	Shift reaction
$H_2 + CO_3^{2-} \Rightarrow H_20+ CO_2 +2e^-$	Anode half-cell reaction
$CO_2+1/2\ O_2+2\ e- \Rightarrow CO_3^{2-}$	Cathode half-cell reaction)

Advantages of MCFCs. Molten carbonate fuel cells can approach efficiencies of 60 percent and overall fuel efficiencies can be as high as 85 percent when the waste heat is captured and used.

MCFCs do not need an external reformer to convert energy-dense fuels to hydrogen. These fuels are converted to hydrogen within the fuel cell because of its high operating temperature. This is called internal reforming.

1. Sintering is a process in which powdered metals are compressed into a mold at 30 to50 tons per square inch and heated to bond the metal together.
2. Doping is chemically bonding something to the surface of a material.
3. A catalyst is a chemical that helps a reaction work without being consumed by the reaction

Problems with MCFCs using digester gas. Although they are more resistant to impurities than other fuel cell types, MCFC they do become "poisoned" with sulfur and particulates. To reduce poisoning, the fuel must be cleaned before it is fed to the fuel cell.

Why the temperature must be kept stable. A temperature drop from 1,200°F to 1,110°F results in almost a 15 percent drop in cell voltage. This is due to increased ionic and electrical resistance and a reduction in electrode kinetics. However, operating at these high temperatures shortens the life of the fuel cell because of material corrosion and electrolyte loss.

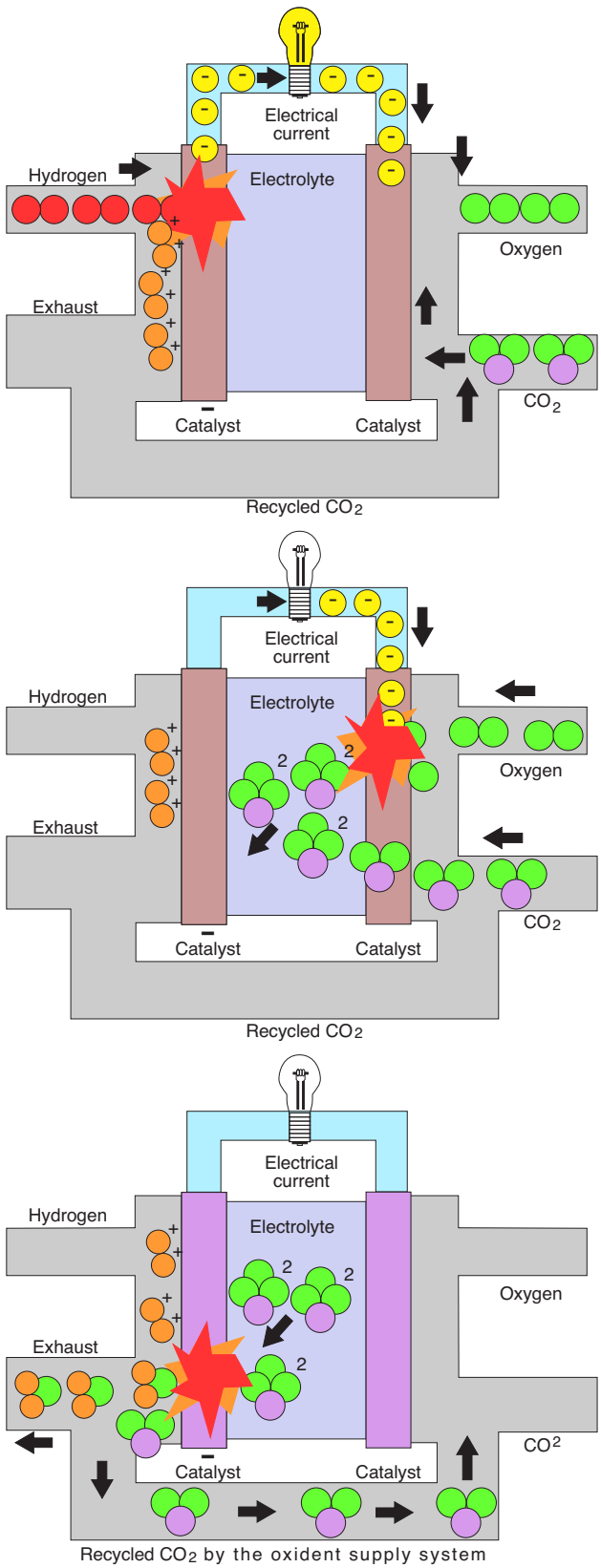
Heatup and cooldown rates are critical to avoid stressing the fuel cell stack module during the period when the salts change state.

FuelCell Energy's fuel cell

The fuel cell is designed to produce 1 MW of power (net AC at the inverter terminals) with a fuel gas-to-carbon ratio of 2 to 1. It should be able to use at least 60–74 percent of the available fuel throughout its life. The system can also be upgraded to produce 1.2 to 1.5 MW of power. The system piping is designed so the fuel cell stack module can be changed out if needed.

Natural gas vs. digester gas

The fuel cell stack is fueled either with unscrubbed anaerobic digester gas or "natural gas"—a pipeline quality methane. (The scrubbed digester gas normally sold to Puget Sound Energy). "Natural gas mode" refers to scrubbed methane and "digester gas mode" refers to unscrubbed digester gas.



Molten carbonate fuel cell

1.3 Overview of the Fuel Cell System

The fuel cell system includes a portable startup heater and blower, fuel preparation system, an oxidizer, the fuel cell stack module, the exhaust gas polisher, and the power conditioning module. During normal operation, the plant is either heating up, in hot standby, generating power, or cooling down.

The fuel cell system has several support systems: digester gas conditioning, water preparation, instrument air, and nitrogen purging. It also supports a heat recovery system that uses flue gas to heat water in a boiler to supplement plantwide heating. The part of the heat recovery system that is about plantwide heating is covered in the *South Treatment Plant Operations Manual, Volume 1, Plant Overview* (Section 5).

Portable startup heater and blower

A portable heating unit and blower is attached to the fuel cell system to cold start it. Once the system reaches 250°F, the heater and blower are isolated (to prevent damage to the blower) and removed from service.

Fuel gas preparation system

The fuel gas preparation system treats scrubbed methane. Once cleaned, the gas is used as part of the oxidant fuel. When the plant is in "natural gas" mode, the cleaned gas is used as part of the anode fuel for the fuel cell stack module.

The fuel preparation system has an electric gas heater, desulfurizers, a fuel humidifier, a fuel deoxidizer, preconverter, and superheater.

The system controls the amount of gas used to makeup the anode fuel and monitors the methane and oxygen concentrations of the anode fuel to learn the "carbon content" that will be used to maintain the steam-to-carbon ratio set by the fuel cell stack and preconverter operating requirements. It controls the steam-to-carbon ratio by modulating the amount of water added to the fuel mixture.

The gas is first preheated by an electric heater to 69°F. Cold gas desulfurizers then remove sulfur compounds, odorants, and other contaminants.

The fuel gas is then humidified using purified water from the water treatment system. (The fuel humidifier is part of the heat recovery system.) The steam-to-carbon ratio is maintained by the water injection rate.

The humidified gas passes through a fuel deoxidizer to remove oxygen (if present) and a preconverter to remove C2+ hydrocarbons and generate the initial hydrogen gas. Finally the gas is superheated in the fuel superheater (part of the heat recovery unit).

Anode gas oxidizer — oxidant supply system

The anode gas oxidizer (AGO) or oxidant supply system has an air blower and a burner with an oxidizer. The air blower (200-BL-101) is 50 hp with a rated capacity of 5,000 scfm at 30 inches WC. The oxidizer (200-HF-101) is a 8 MMBTU/hr burner. The catalyst section or the burner system has a capacity of about 8.7 cubic feet and is designed to run at 10 psi with temperatures between 650°F to 1,300°F.

The AGO collects the anode exhaust gas from the fuel cell stack module, mixes it with excess air from the air blower, catalytically oxidizes the stream to remove excess hydrogen (H2) or methane (CH4), and delivers the oxidant gas to the fuel cell stack module. The system generates cathode oxidant gas at the flow rate, composition, and temperature needed by the fuel cell for power generation.

The oxidant supply system also integrates the operation of the fuel cell anodes and cathodes during power generation. Air is heated for oxidant fuel using the residual fuel energy and the heat in the anode exhaust gas. By recirculating the carbon dioxide generated in the fuel cell anodes back to the fuel cell cathodes, it supports the cathode reactions.

The oxidant supply system also provides heat and control to heat up and cool down the fuel cell stacks during plant startup, shutdown, and standby operation. By burning desulfurized methane with air, it generates a hot effluent gas at the temperatures and flow rates needed for

Proprietary Information— Not Available for Publication.

heating. (Treated digester gas from the digester gas conditioning system cannot be used for AGO burner fuel because the heating value is too low).

Heat recovery system

The heat recovery system uses waste heat from the cathode exhaust gas to humidify and preheat the digester gas or natural gas/scrubbed digester gas feed, superheat the anode fuel gas, and vent the cooled cathode exhaust gas to the atmosphere. As part of the fuel cell system, the heat recovery system collects the cathode exhaust gas exiting the fuel cell stack module. It polishes the cathode exhaust gas to remove residual methane and carbon monoxide to increase the temperature of the flue gas upstream of the fuel superheater.

The system includes a part of the cathode exhaust gas piping to the heat recovery unit (HRU). The heat recovery system has dampers around the fuel humidifier coils to maintain the optimal temperature to the preconverter for the best performance.

The heat recovery system has a nozzle for extracting flue gas to heat water in the plantwide HRR/HRS loop.The heat recovery system also has a nozzle to return the cooled flue gas to the heat recovery unit exhaust stack.

Fuel cell stack module

The fuel cell stack module receives superheated anode fuel gas from the fuel gas preparation system and hot cathode oxidant gas from the oxidant supply system. The stack converts the energy in the anode fuel to electrical energy by generating direct current (DC) electric power for the inverters. The inverters convert the DC power into alternating current (AC).

The anode exhaust gas is discharged to the oxidant supply system and cathode exhaust gas is discharged to the heat recovery system.

The fuel cell stack module contains about 400 fuel cell plates arranged in 4 stacks. Each fuel cell stack is made up of a series of reforming units, there is one reforming unit for eight fuel cell packages, and each fuel cell package has a total active area of 7,800 cm^2. The stacks are gas-tight to 2 psig to provide environmental containment. Fuel gas is fed to the reforming unit, and then travels to the anode. The anode exhaust gas is sent to the oxidant supply system for CO_2 recovery. Oxidant is fed to the cathode, and the cathode exhaust is routed to the HRU.

1.4 Overview of the Electrical Conditioning and the Support Systems

Once DC electricity is created by the fuel cell, it must be converted to AC power that can be used by our equipment. This process takes place in the electrical conditioning part of the fuel cell system.

The fuel cell system also has several other critical support systems. The digester gas conditioning system provides the fuel for the anode when the system is running in "digester gas mode." The nitrogen purging system provides a safety net for both equipment and people, and is critical enough that the fuel cell system cannot be started unless this system is at pressure. The instrument air (IA) system provides air to the anode gas oxidizer (AGO) burner pilot purges the electrical panels, and operates the pneumatic control equipment. The water treatment system, another important support system, is covered in the next module.

Electrical equipment

The electrical conditioning system is part of the electrical balance of plant (EBOP). It converts the DC electric power generated by the fuel cell stack module to AC electric power. It contains all the electrical system protective devices and the distribution and control devices for auxiliary loads. The electrical interface is either tied directly into an electrical transformer or into an electrical panel. A UPS provides enough backup power to shut down the electrically controlled equipment in case of a utility power loss.

Digester gas preparation system

This system treats and conditions the raw digester gas for use as fuel to the anode side of the fuel cells.

Knockout drums. Raw digester gas is passed through a knockout drum to remove entrained liquids and then fed to a compressor. The compressed gas is then cooled and passes through a second knockout drum, where condensed liquids are removed.

Compressor. The treated digester gas is then compressed and supplied to the fuel gas preparation system upstream of the heat recovery unit fuel humidifier.

The digester gas compressor is rated to compress 20 to 354 scfm of gas to about 26 psi. The compressor is an oil-lubricated, rotary-vane compressor with a variable speed drive, and a jacket water cooling system.

SulfaTreat bed. The gas is then fed through a SulfaTreat bed for bulk sulfur removal (to <10 ppm). The SulfaTreat bed material is made of ferric and triferric oxides supported on the surface of an inorganic substrate.

Activated carbon polishers. Effluent digester gas from the SulfaTreat bed is passed through potassium hydroxide (KOH) impregnated activated carbon beds (two in series) to remove trace sulfur compounds (to <0.1 ppm). The impregnated KOH helps remove COS and SO_2. Theoretically it also removes trace quantities of siloxanes and organic chlorine compounds.

Wastes. The cooling water and condensed liquids is returned to the sewage treatment plant. The spent bed material is considered environmentally benign and can be dumped in a landfill.

Nitrogen purging system

The nitrogen is stored in two six packs of pressurized gas bottles, and is used for the following:

- To provide an inert gas curtain in the fuel cell cathode exit piping when the plant is placed in shutdown mode. This prevents the vacuum in the stack module, created as the module cools down, from drawing in air and moisture from the outside.
- To purge the fuel gas piping and fuel cell anodes in shutdown mode to prevent nickel carbonyl formation (within the pre-reformer and the fuel cell reforming units). The purging also prevents moisture from condensing in the pre-reformer and the fuel cell reforming units (RU). This system is called anode cover gas.

Nitrogen gas is also used for maintenance procedures, and is supplied by portable tanks. These maintenance activities include the following:

- Purging the fuel gas piping and fuel cell anodes before the first startup.
- Purging the fuel gas piping before and after maintenance procedures, purging the cold gas desulfurizers, the SulfaTreat vessel, and the digester gas polishers before change-out.

Anode cover gas system

Anode cover gas is needed during the rapid restart process or trip recovery, whenever fuel gas had been flowing before the trip.

Two 200 cu.ft. cover gas cylinders are connected to the cover gas header using flexible hose. Each cylinder can be isolated. When not in use, both bottles are isolated at the bottle until needed to reduce the chance of a small leak draining one or both bottles.

One bottle is used at a time. The cylinders are mounted on a rack near to the gas analyzer calibration gas cylinders. The cover gas is mixed with 1 scfm of pure nitrogen from the purging system. The anode cover gas line is tied into the 3-inch mixing tee at the anode inlet.

Instrument air

The IA system supplies compressed air to control pneumatically-operated valves, to support the AGO burner operation, and to purge panels. The IA system has two compressors, two receivers, two air dryers, and is equipped with two prefilters, and two afterfilters. The system can compress and dry 25 scfm to 125 psi with a dew point of -40°F. The instrument air receivers supply enough reserve air to shutdown the plant and operate all the valves in case of a utility power loss.

Calibration gas

There is a calibration gas manifold that contains the various gases used to calibrate the gas analyzer.

Water treatment system booster pumps

There is a shed, north of skid 1, that contains two booster pumps used to produce high pressure water for the water treatment system.

Reference

1.5 Overview of the Water Treatment System

The water treatment system is designed to provide 2.2 gpm of deionized water for use in a fuel gas humidifier. The system includes: pretreatment equipment (an activated carbon filter, a JelCleer media filter, twin water softeners with regeneration brine tank, a chemical injection station, and cartridge filtration), a reverse osmosis unit, a continuous deionization unit, three mixed-bed service deionization units, a deionized water storage tank, and deionized water transfer pumps. The water treatment system is controlled through an Allen Bradley 5/03 PLC with a Panel View 550 operator interface. The PLC interfaces with the distributed control system (DCS) using a MCM-3150 Pro-Soft "Modbus" interface card.

Pretreatment system

City water normally enters the pretreatment system at 5.7 gpm at 80 psi (regulated to 60 psi). The flow rate can increase to 15 gpm as needed during backwashing of system components.

Carbon filter. As the feed water enters the system, it flows through the granular activated carbon filter. The carbon filter (FL-1, 16 inches diameter x 65 inches) is straight-sided and designed to operate at 100 psig. All piping connects to a multi-port valve head and controller on top of the vessel. The filter removes chlorine as the feed stream flows through a bed of acid-washed activated carbon media. (The PLC periodically backwashes the carbon filter to flush out contaminants and reclassify the bed.)

The JelCleer filter. The flow from the carbon filter enters the JelCleer media filter (FL-2, physically similar to FL-1) removes fine colloidal matter, reduces the silt and minimizes the fouling of reverse osmosis unit membranes. (The PLC periodically backwashes the filter to flush out contaminants.)

Water softener. The flow from the JelCleer media filter enters the water softeners (WS-1/2). The two softeners are controlled by a single multi-port valve head and controller. Normally, one softener is in service, and the other is regenerating or in standby. Each softener is 14 inches in diameter by 65 inches, straight sided, and designed to operate at 100 psig.

As the water flows downward through the bed of resin of the online softener, the ionic exchange removes calcium, magnesium, and certain trace metals from the water.

During regeneration, the captured elements are flushed out to restore the resin to its full working capacity.

The regeneration system has a rectangular tank (TK-1, 30x48x60-inches) containing a saturated brine solution that is used to regenerate the softener resin. When the output flow totalizer indicates when a softener needs regeneration, the unit controller switches leads, puts the softener in regeneration, and pulls this highly concentrated brine into the softener and dilutes it with water. The softener is backflushed at 5 gpm. After regeneration, the softener is put in standby.

Antiscalant system. The flow from the water softeners passes through the antiscalant injection station. An operator-adjustable metering pump (PU-1) injects an antiscalant solution from a 120-gallon double-walled storage tank (TK-2) into water to stop salt scale from forming on the osmosis membranes. A mixer is mounted on the storage tank.

Prefilters. After the chemical injection site, the water flows through three cartridge-prefilters (FL-3, 4, and 5) connected in parallel. Each polypropylene prefilter housing contains 5-micron cartridges. Normally, all three filters are in service. Isolation valves allow a prefilter to be removed from service for maintenance while the others stay in service.

The output of all the in service prefilters is combined and sent to the inlet of the reverse osmosis unit.

Reverse osmosis unit

High pressure pump. The flow from the RO prefilters (5.7 gpm), is combined with 3 gpm from

a RO reject recycle line. The combined 8.7 gpm flow is then pressurized by the high pressure (booster) pump (PU-2) and directed through reverse osmosis unit. The RO high-pressure (booster) pump has a 5 hp TEFC motor and is rated at 3,500 rpm.

Reverse osmosis unit. The reverse osmosis unit consists of four FRP pressure vessels arranged in a single-pass, four-stage, 1:1:1:1 array. The vessels in this array are rated for 300 psig. Reject water from the last vessel is split into two streams: 3 gpm is recycled, and 2.3 gpm is sent to a drain. An automatic flow control valve in the reject water line maintains 3.4 gpm of product water to the deionization unit, and 3 gpm of reject water to the high pressure pump. The RO unit is Model #41 240 and has a 50 percent recovery rate at 32 gpm and 300 psi.

The product from the reverse osmosis unit flows to the continuous deionization unit.

Deionization system

Continuous deionization unit. The incoming flow is split for the two inlets of the deionization unit. About 0.4 gpm of reject flow or electrode flow that contains impurities is sent to a drain. The deionization unit is a continuous electrode ionization system model CDI LX-100A1XX that operates at 100 psi max and 5 gpm.

Polishing units. The 3 gpm of product water from the deionization unit flows to the mixed-bed service deionization units. Three removable mixed-bed units (MB1, 2, and 3) connected in series and operate as primary, secondary, and polishing units. Manual isolation valves allow removal and replacement. When increasing conductivity at the outlet of the secondary unit indicates that the unit is exhausted, the system is shut down and the primary and secondary units are removed. The polishing unit is moved into the primary position and fresh replacement units are put in the other two positions. The system is then returned to service.

Normally the deionized water flows at 3 gpm from the polishing units through the automatic deionization storage tank inlet valve and into the tank.

Recycling for low conductivity. A recycle line is provided downstream of the polishing unit. The recycle line connects the polishing unit discharge to the input of the reverse osmosis unit. When recycling the PLC opens the automatic valve in the recycle line and closes an automatic inlet valve on the deionized (DI) water storage tank, (the line from the polisher), to establish a loop. The conductivity at the output of the polishing unit is periodically measured, if the conductivity is too high the water is recycled, if it remains too high the system is shut down.

DI storage tank. The deionized water storage tank (TK-3) is stainless steel, 102 x 36 x 114 inches, and holds 1,800 gallons. It has a 0.2-micron hydrophobic vent filter. The tank has an inlet for normal flow (from the polisher). A level sensor in the tank controls the flow of water into the tank.

If the water in the tank is at high level, the PLC closes the tank inlet valve and recycles the water. This allows the reverse osmosis unit and deionization units to remain in service until the level in the tank drops. A low-low tank level shuts down the downstream DI water transfer pump until the level in the tank rises. This shuts down the fuel cell system.

DI water transfer pump. If the tank is full, at the beginning of Heatup 2 the lead DI water transfer pump starts and feed water at 5 gpm and 190 psi. The system has two transfer pumps. At the pump outlet the flow is split, up to 2.2 gpm is sent to the fuel cell, and 2.8 gpm flows to the inlet of the service deionization (SDI), the mixed bed units and carbon filters. The two deionized water transfer pumps (PU 3 and 4) are Grundfos #CRN2-100g). They can pump 5 gpm at 185 psi and have 3 hp TEFC motors. Flow sensors in both lines are monitored by the PLC.

Reference

For a schematic of the water system see “Overview of the Water Treatment System Controls” on page 22.

1.6 How the Fuel Cell Is Controlled

The fuel cell is controlled by a distributed control system (DCS). The DCS interfaces with four system PLCs. The DCS computer (DeltaV) and several of the PLCs have local operator interfaces (OIUs). The operator stations are called the App-Station and the Pro-plus station. The DCS can also be remotely monitored by Fuel Cell Energy (FCE) using the Internet or a dial up connection.

The FCE operator's role

The fuel cell is designed for unattended operation, with local and remote dispatching of a FCE operator. Only the FCE operator can start up the fuel cell, and this cannot be done remotely. A FCE operator must attend all fuel cell plant startups (from a cold condition with fuel cell stacks at ambient temperature) and plant restarts (from a warm condition with the fuel cell stacks at elevated temperature). All nitrogen bottles must be replaced before starting or restarting the plant, and the FCE operator must witness the light-off of the oxidizer burner.

The pumps, blowers, and most other components can be remotely started, assuming all permissives have been satisfied. Because the plant is designed for unattended operation, alarms will trigger the pager of an on-call operator who can access the DCS from the Web server using the Internet, or a dial up connection.

High-high or low-low alarms, which need immediate action, trigger an automatic response that either puts the fuel cell system in a safe operating mode or shuts down the system.

For cold starts, a portable heater and blower must be used temporarily to warm up the fuel cell stack module to 250°F.

NOTE: The South Plant provides the following items: nitrogen bottles, city water, digester gas, and "pipeline quality" scrubbed digester gas.

Control system

The fuel cell system is controlled by a distributed control system (DCS) with four PLCs and two operator stations: the oxidizer's burner management system (BMS), the water treatment system controller, the digester gas compressor controller, and the power conditioning system (PCS). The DCS system uses both electric and pneumatic control elements.

Operator interface unit. The DCS has two operator interface (OIU) or work stations called the engineering/operator work station (ENG/OWS) or Pro-plus and App-Station. There is a printer (for maintenance). It will be housed inside the electrical balance of plant (EBOP) or power conditioning enclosure, but is currently in the construction trailer. The DCS has a telephone modem and pager software that annunciates alarms to the FCE operator's pager (beeper), who is responsible for the fuel cell. The fuel cell can also be monitored at FCE facilities in Danbury, CT.

All operator commands made from the OIUs consist of two steps: command and execute, the same as Forney. At least three levels of access to the OIU display are available, one for operators, one for supervisors, and one for maintenance. Several levels of remote paging are also available, depending on the type of alarm.

NOTE: All differential temperatures are displayed as outlet minus inlet. A negative number indicates a temperature drop, a positive number indicates a temperature rise.

Forney. Some alarms and status points are available from Forney. Forney also displays system status including hold states and some alarms.

LAP 21. LAP 21 is found inside the gray cabinet next to the heat recovery unit at the fuel cell. It annunciates alarms for the plantwide heat loop system. The heat recovery system uses the fuel cell flue gas to heat water in a boiler, this system is not covered in this manual.

Digester gas preparation system panel. The control panel is near the anaerobic digester gas (ADG) preparation equipment. It displays equipment alarms and status and provides control of the system, the compressor, and the enclosure fans.

Burner management system panel. The Burner management system (BMS) panel is located on

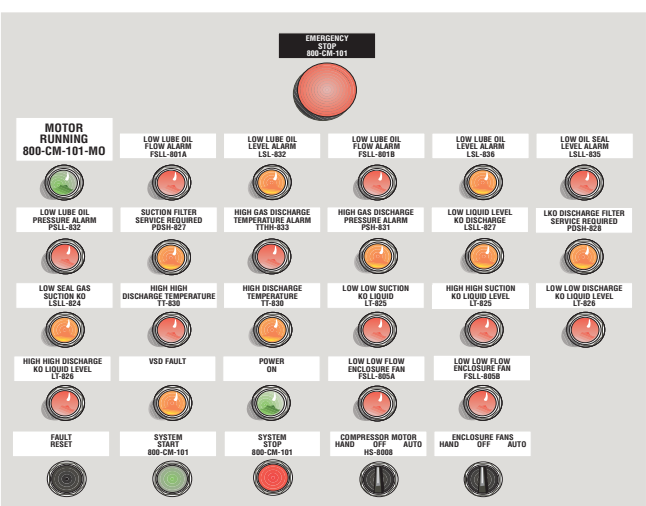
the east side of the anode gas oxidizer (AGO) burner. It displays alarms and has reset buttons for the system.

Control system responses

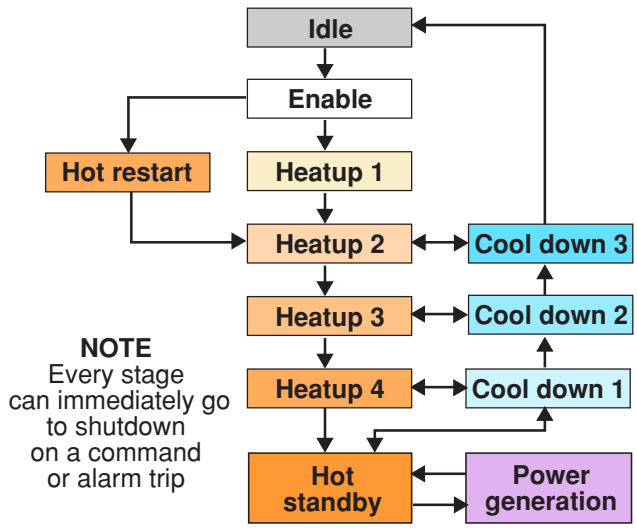
Fire alarm panel. A fire panel collects signals from several UV/IR flame scanners, combustible gas detectors (LEL or H_4) and toxic (H_2S) gas monitors within the fuel cell system area. It uses a horn and three differently colored flashing lights to annunciate the alarms. Although the alarms register on the fire alarm panel, the fire panel uses the DCS to shut down the fuel cell system. All these alarms must be silenced and acknowledged manually at the DCS and at the fire panel.

Alarm responses. Fuel cell system alarms trigger what Fuel Cell Energy, Inc. calls a plant protective response (PPR). The least severe response is a fuel cell heatup hold; the most severe is a system shutdown. Three staged responses stop short of shutting down the fuel cell system: a heatup halt, a reduced kW production step down, and a hot standby step down.

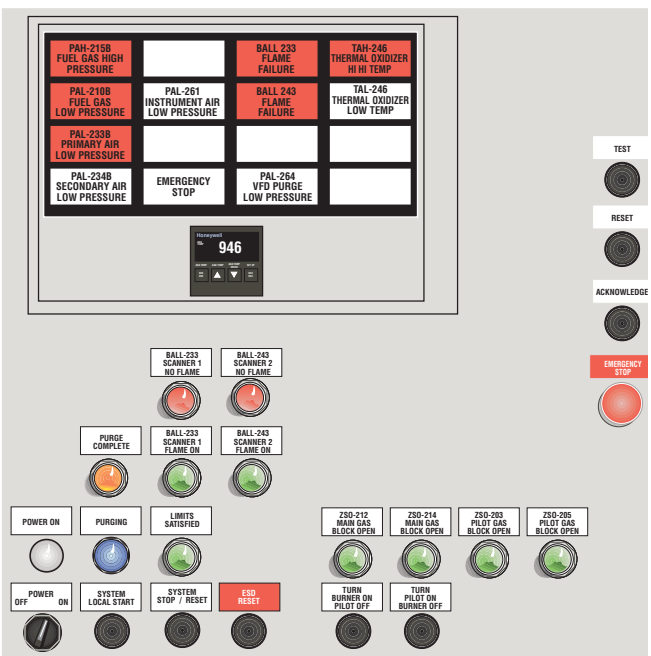
Shutdown responses. Any condition that could damage the fuel cell stack or other system equipment results in a full plant shutdown and nitrogen purge. Depending on the problem, the system will shut down in one of three ways: a shutdown with auxiliary power available, a shutdown with no power available and the computer on UPS power, or a shutdown with a computer failure. All shutdowns must be manually reset.



Digester gas preparation system panel



The control system uses several modes to keep the fuel cell system active. Normally the system is either heating up, cooling down, in hot standby, or generating power



Burner management system(BMS) panel

1.7 Using the Operator Interface Units

The distributed control system (DCS) operator interface unit (OIU) uses screens to interact with the computer program. There are several types of screens and ways of accessing the information that you will need. The PLCs that run the individual systems also have OIUs; however these PLCs normally run as a part of the DCS system.

Common buttons

Common buttons are at the top of each screen.

- Exit program
- Print the current screen
- Search for and open a faceplate screen
- Search for and opens detail screen
- Display directory, not used
- Resets to the entry screen
- Search for and open a screen
- Open last display
- Overview screen
- Alarm list screen
- Acknowledge all
- Area alarm filtering
- Alarm supress
- Delta V login
- Flex lock
- Diagnostics
- Delta V explorer
- Control studio
- Process history view
- Trip to hot standby (puts the fuel cell in hot standby)
- Operations mode control screen
- Operating conditions screen
- Plant trip (shuts down fuel cell system)
- Delta V system time
- Delta V help
- Books on-line

Below the row of common buttons, most screens display the time and date, plant target mode, actual plant mode, facility name, and present screen name.

Navigating

Overview screen. The overview screen provides:

- General view of plant flow paths and interconnections
- Access to most P & I drawings
- Access to plant information screens
- One stop shopping for verification of shutdown actions
- Overview of important plant temperatures related to air and fuel flow paths

Plant status screen.

This screen captures the big picture parameters such as: gas, water and air flow; cathode and anode in/out temperatures; and AC and DC electric power generation:

Plant settings screen. This screen is accessed from the gray button pallet on the upper right side of the overview screen. It allows you to change important plant settings without going into the Delta V control studio such as: ramp rates, heatup and cooldown logic, gas and water enable interlocks, total air flow rate of change, etc.

Operation mode control screen. This screen give the present mode and transition options and allows you to select automatic or manual transitions. It also gives you access to transition checklists and plant hold switches.

Using transition checklists. Transition checklists pop up automatically when you select a new mode. The checklists can also be accessed by selecting MODE TRANSTION CHECKLISTS from the Operating Mode Control screen (select the OP MODE button to bring up this screen).

- The **blue type** shows the information the operator determines
- The **black type** shows the information the system uses
- Conditions that are met have ✔(green check marks)
- Conditions that are NOT met have red **X**s. (As long as a red **X** is displayed the transition to the next stage will not take place.)

Using faceplates. Faceplates are accessed by pressing the faceplate button.

- Faceplates provide access to the details screen and control studio. From detail screens, you can modify any displayed parameter without accessing the control studio. They also provide diagnostic information
- From a standard faceplate you can start a trend, access historical data in a trend form, or view set points, outputs, and process parameters. Alarms associated with the face plate may also be acknowledged from the faceplate.
- Set point ramp screens are a type of faceplate. These screens track ramp status, some the the settings can be changed from this screen, other settings must be changed from the plant setting screen. You can also change ramp status from these screens.

  Ramp help screens associated with ramp faceplates show the conditions that will stop the ramp. The condition's type changes from **green** to **red** if the condition causes a ramp hold.

Shutdown trip screen. This screen gives status information on plant shutdowns, emergency shutdown switches, reduced power trips, hot standby trips, and the gas and fire alarms. This screen is selected from the OVERVIEW screen.

Alarm list screen. An alarm list screen displays all the active or unacknowledged alarms.

- A check mark next to the alarm means it has been acknowledged.
- A cross hatched square next to the alarm means the alarm has reset and will clear when acknowledged.
- A red background around an alarm means that it is a critical alarm.
- A yellow background around an alarm means that it is a warning.
- A purple background around an alarm means that it is an advisory.

Acknowledging alarms

Acknowledge alarms from the alarm list screen. Use the bell with a check mark and a "1" button to acknowledge one alarm at a time. Use the bell with a check mark button to acknowledge all alarms.

Operating the DCS (DeltaV) computer

There is a distributed control system computer (DeltaV) and two work stations (Pro-plus and App-station). There are also local PLCs that control the various systems. All must be up and running to operate the fuel cell system.

1. **Be sure the EBOP has power and the controller is turned on.**
2. **Check power is on to the modem and hubs.**
3. **Turn on the Pro-plus computer**
   a) At the Pro-plus station, turn power ON
   b) Press CTRL-ALT-Delete
4. **Log on the Pro-plus computer.**
   Enter the following information:
   - User name – _____
   - Password – _____
5. **Log on to the DELTAV computer**
   Enter the following:
   - Computer – KC2PPLUS
   - User name – _____
   - Password – _____
6. **Enable the FLEX LOCK.**
   Go to the NT desktop, from the START menu, select DELTAV, OPERATOR, and DELTAV OPERATE.
7. **Turn on the App-Station computer.**
   a) Turn power ON
   b) Press: CTRL-ALT-Delete

8. **Log on to the App-Station computer, enter the following information:**
   - User name – _____
   - Password – _____
9. **Log on to the DELTAV computer, enter the following:**
   - Computer – KC2APPSTN
   - User name – _____
   - Password – _____
10. **Enable the FLEX LOCK.**
    a) Go to the NT desktop, from the START menu, select DELTAV, ENGINEERING, FLEX LOCK
    b) From FLEX LOCK: select OPERATOR INTERFACE

Shutting down the Delta V computer

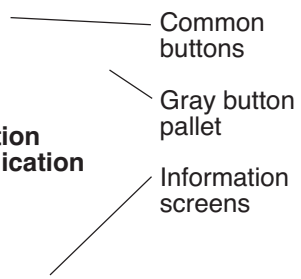
1. **Shut down the Pro-plus computer**
   a) Close the DELTAV OPERATE
   b) Close the DELTAV EXPLORER
   c) Close any programs that remain open
   d) Select START, and then SHUTDOWN
2. **Shut down the App-Station computer**
   a) Close the DELTAV OPERATE
   b) Close EXCEL
   c) Close any programs that remain open
   d) Select START, and then SHUTDOWN

Operating the Fire Alarm Panel

The panel must have power, verify breaker B‘6‘B is closed.

Verify communication to the DCS — no alarms.

Proprietary Information Not Available for Publication



Overview screen

Proprietary Information Not Available for Publication

Plant settings screen

Reference

1.8 Handling the Effluent Streams

As with any system there are waste products that need to be handled. Most of the waste produced by the fuel cell system is harmless. Air emissions are treated and released into the atmosphere. Water is returned to the plant headworks. Used catalysts are sold to catalyst reclaimers. The spent sulfur absorbent is either returned to the supplier for regeneration or disposal. The SulfaTreat absorbent is disposed of in a landfill.

Continuous effluent streams

Continuous effluent streams from the plant during normal operation are as follows:

- Fuel cell cathode exhaust gas passes through the heat recovery unit and exits to the atmosphere. Air pollutant emissions in this exhaust gas are negligible. SO_x emissions are essentially zero because the fuel gas feed to the fuel cells contains less than 0.1 ppm sulfur. NOx emissions are low because the oxidizer and fuel cells operate at relatively low temperatures. Methane and carbon monoxide emissions are reduced to nearly zero by the polisher in the heat recovery unit.
- Reject/regeneration/backwash water from the water treatment system are disposed into the plant sewer system.
- Whenever digester gas is used, two more liquid effluents are produced. The cooling water used to cool the digester gas in the digester gas aftercooler is dumped to an open sewer. The process condensate that is generated in the digester gas conditioning system that drains into a closed sewer. This water does contain oil from the digester gas compressor and trace sulfur from the digester gas. Both sewers will return the effluent to the plant headworks.
- Solid wastes include spent sulfur absorbents and deactivated catalysts. The spent waste material is collected in waste bins before being shipped offsite.
  - The preconverter and oxidation catalysts (from the deoxidizer, oxidizer, and heat recovery unit exhaust gas polisher) are suitable for recycle/sale to catalyst reclaimers.
  - The spent sulfur absorbent (from the cold gas desulfurizers and digester gas polishers) is returned to the supplier for regeneration or disposal, and the SulfaTreat absorbent is disposed of as a non-hazardous waste.

Intermittent waste

Other intermittent wastes are as follows:

- Lube oil that must be replaced in the equipment according to vendor specifications.
- Rainwater or washdown water can be directed to a stormwater drain.
- Oil leakage beneath rotary equipment is contained and can be cleaned up during regular maintenance.

Reference

1.9 Location and Layout of the Fuel Cell System

The fuel cell system is located near the reuse storage tank on the corner of Road Q and Road K. The area has sensors for combustible and toxic gas, and fire. Most enclosures have ventilation fans that must be operating for the fuel cell system to run.

Emergency shutdown buttons

There are six system wide emergency shutdown buttons. One is on either side of the electrical balance of plant (EBOP) cabinet, one near the instrument air system, one across from the fuel cell stack module near the anode gas oxidizer (AGO) burner, one on the corner of the fuel gas preparation section of skid 1, and one on the southwest corner of the digester gas preparation enclosure.

There are two local system emergency shutdown buttons one on the digester gas preparation system control panel, and one on the burner management system (BMS) panel. The instrument air system also has two local emergency stop buttons, one near each door.

Lower explosive limit meter locations

- **Fuel gas preparation system and digester gas conditioning system.** Leaks of treated digester gas downstream from the SulfaTreat vessel and natural gas/scrubbed digester gas downstream from the cold gas desulfurizers can not be detectable by smell. Combustible gas (LEL) detectors are strategically installed to detect methane gas and fuel gas leaks in the fuel gas preparation system and digester gas conditioning system.
- **Anode exhaust gas piping.** The anode exhaust gas contains carbon monoxide, and is highly poisonous. Strategically located combustible gas detectors (LEL) are installed to detect carbon monoxide leaks in the anode exhaust gas piping.
- **Fuel cell stack vessel**. Two combustible gas detectors (AE-342A and B) are located inside the fuel cell stack module. An LEL of 25 percent registers as an alarm at the fire panel. A level of 60 percent, shuts down the fuel cell and activates a horn and blue flashing light.

Freeze protection

The cold gas desulfurizers are maintained in a heated enclosure at 60°F or above to improve absorption.

The water treatment system equipment is maintained in a heated enclosure at 40°F or above to prevent freezing.

The digester gas compressor and associated equipment is maintained in a heated enclosure to prevent freezing and to dampen the sound.

Generally, all piping, instruments, and equipment that contain water or digester gas and are exposed to the ambient are heat traced and insulated to protect them from freezing. Some of the instrument air lines are also heat traced.

Layout

The fuel cell plant is a modular design built on several skids. Removable or hinged panels provide access to the equipment. Some equipment is accessed through panels in the top of the enclosure.

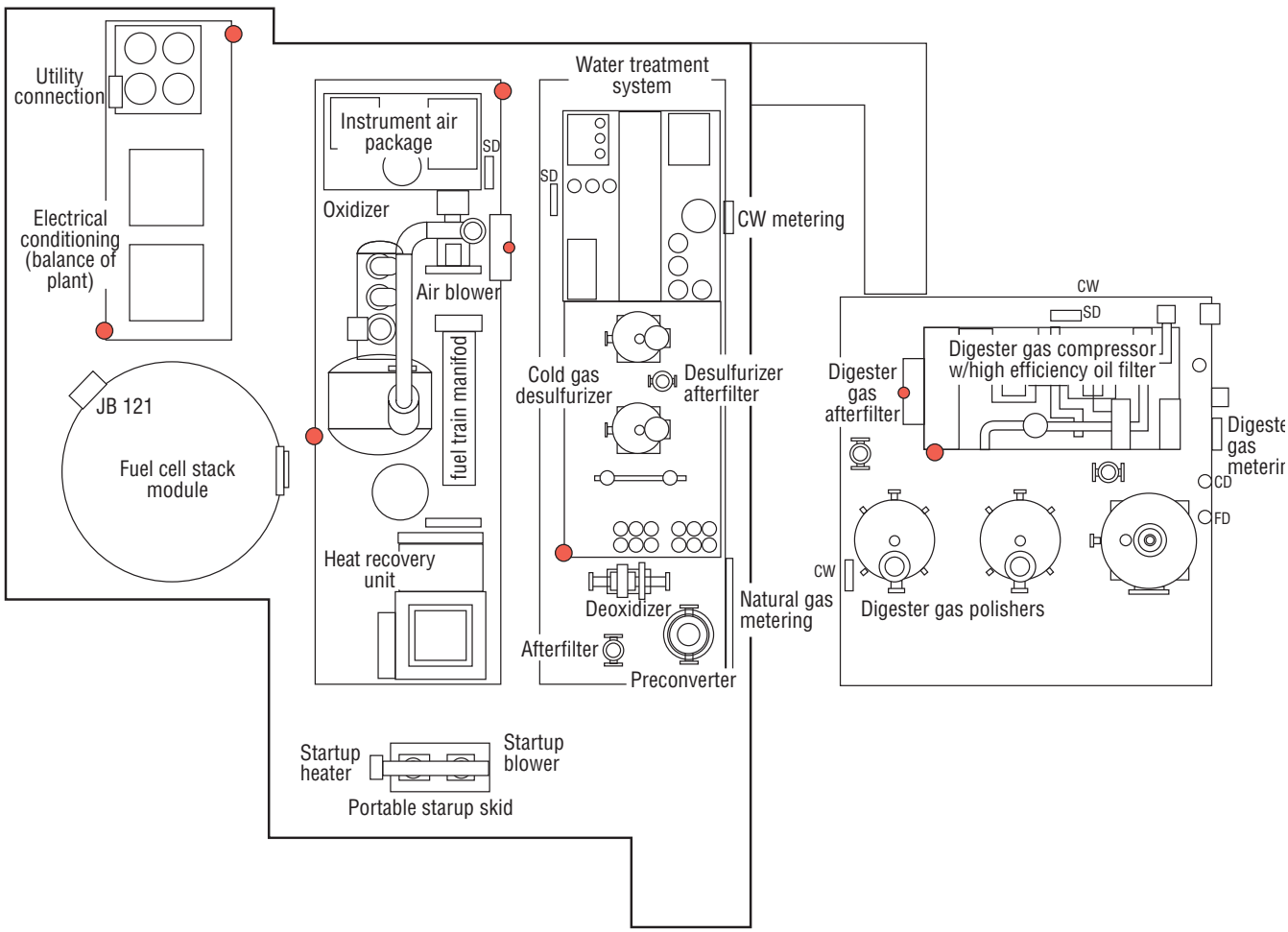
Fuel cell stack module. The fuel cell stack has its own skid. The fuel cell stack module has current posts that conduct lethal DC voltage even after the power has been disconnected. The voltage can remain until the stack has cooled to the temperature of the outside air.

EBOP. The electrical balance of plant (power conditioning) also has its own skid. You must be trained before opening any panels in this skid. Some panels within the skid are 480 V and may only be opened by an electrician.

Startup skid. The startup skid includes the startup blower, heater and its controls.

Skid 1. The water treatment system and fuel preparation system share Skid 1.

The water treatment system consists of the activated carbon filter, water softeners, brine storage tank, reverse osmosis prefilters, pump and array,



mixed bed filter bottles, multimedia filter, antiscalant tanks, the continuous deionization system, the product water storage tank, and the product water pumps.

The fuel gas preparation system has the cold gas desulfurizers, the desulfurizer afterfilter, the deoxidizer, the preconverter, and the preconverter afterfilter.

Skid 2. Skid 2 is also called the AGO (anode gas oxidizer) skid. This skid has the instrument air system, the oxidizer, and the heat recovery unit. The instrument air system includes two compressors, air dryers, filters, receivers, and controls. The oxidizer includes the vessel, a burner, the catalyst, and controls. The burner management system (BMS) control panel is here. The heat recovery unit houses the cathode exhaust gas polishers, superheater coils, humidifier coils, temperature control dampers and supply and return nozzles for the waste heat recovery system. The waste heat recovery system supplies hot water to the South plant HRR/HRS circulation loop (this system is not covered in this manual).

Digester gas skid. The digester gas skid includes the digester gas polisher, SulfaTreat vessel, digester gas oil filter, gas compressor, afterfilter, and its controls. The digester gas preparation system panel is here.

Electrical conditioning system enclosure. The electrical balance of plant (EBOP) (600-EE-1 01) is an outdoor, non walk-in enclosure containing the power conditioning system, DC power fuses, DC grounding circuit, DC isolation diodes, AC utility interconnection circuit breaker and protective relaying, the DCS (DeltaV) computer equipment, a UPS, and the low voltage distribution equipment

1.10 Layout of Skid 1, 2, and EBOP

Some of the equipment is inside enclosures with numbered, removable panels that provide access to the equipment. Each panel weighs about 50 pounds, some are hinged but most lift out. Many of the side panels are held in place by center posts, which can be removed by pulling the release pins. In addition to the two levels of wall panels, there are also panels in the roof.

The EBOP skid

The electric balance of plant (EBOP) skid houses the inverters, breakers, DCS system and UPS.

Skid 2, AGO skid

Skid 2 is also known as the AGO skid.The instrument air section of skid 2 is the north end. The receiver tanks are above the compressors. There are two local control panels one for each compressor, each has a local emergency stop button. The dryer local control panel is on the west side also on the north end of the skid.

The middle of the skid has the anode gas burner, the blower, the burner management system, and (BMS) control panel. The heat recovery unit is on the south end.

DANGER

Be sure that all water treatment system panels are closed and locked in place before removing any fuel preparation enclosure panels, when gas is in skid 1.

Before removing any fuel preparation enclosure panels, verify no one is smoking and that there are no sparks or open flames in the area.

Skid 1

The fuel preparation and water treatment system enclosures of skid 1 are NEMA, Div. 2 enclosures. Use non-sparking brass tools and properly rated electrical equipment when performing maintenance in this enclosure while gas is flowing. The skid is equipped with combustible gas monitors. It has two separate enclosures and 23 panels provide access.

Each heated enclosure is kept at 50°F by a unit heater with a local thermostat. Each has a ventilation fan is used for cooling; it comes on at __°F from a local thermostat. The enclosers are monitored, and high-high and low-low temperature alarms register at the DCS.

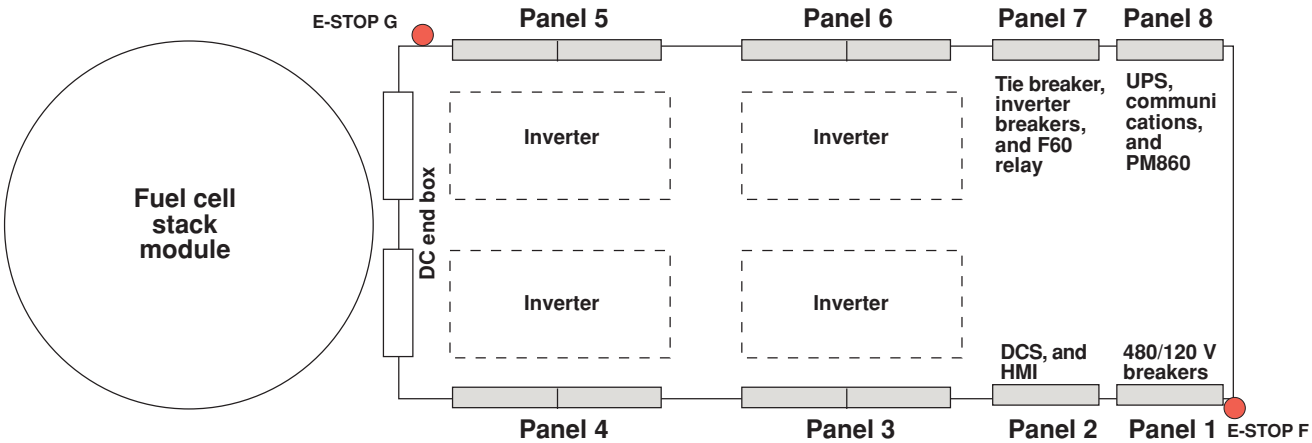
Startup skid

This skid has the blower and heater and the control panel that is used to control the process that preheats the fuel cell.

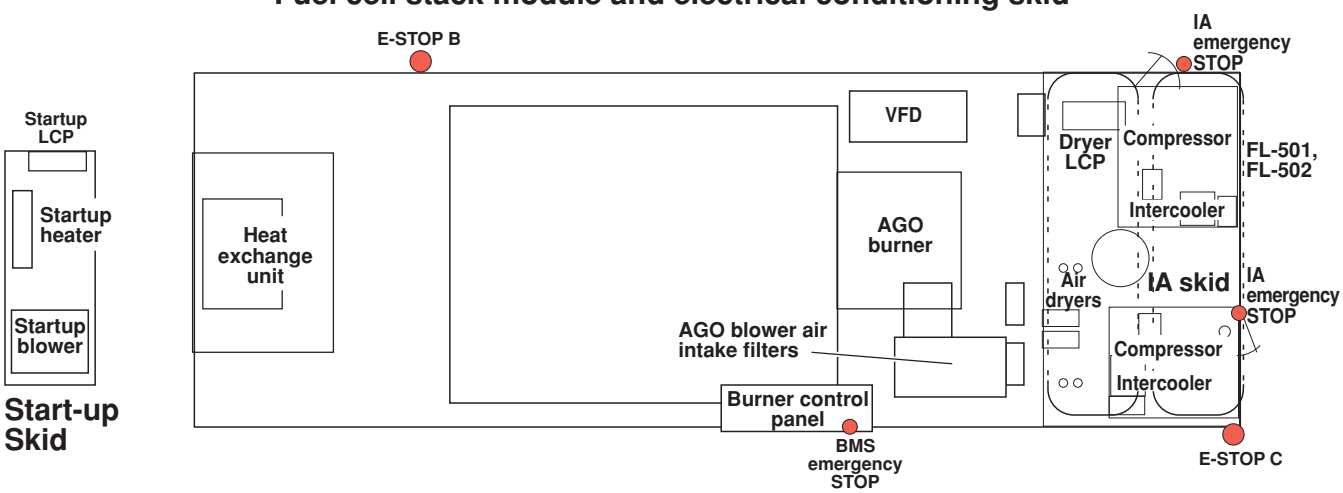
Digester gas skid

The digester gas preparation skid has the equipment used to prepare low pressure sludge gas for use as anode fuel.

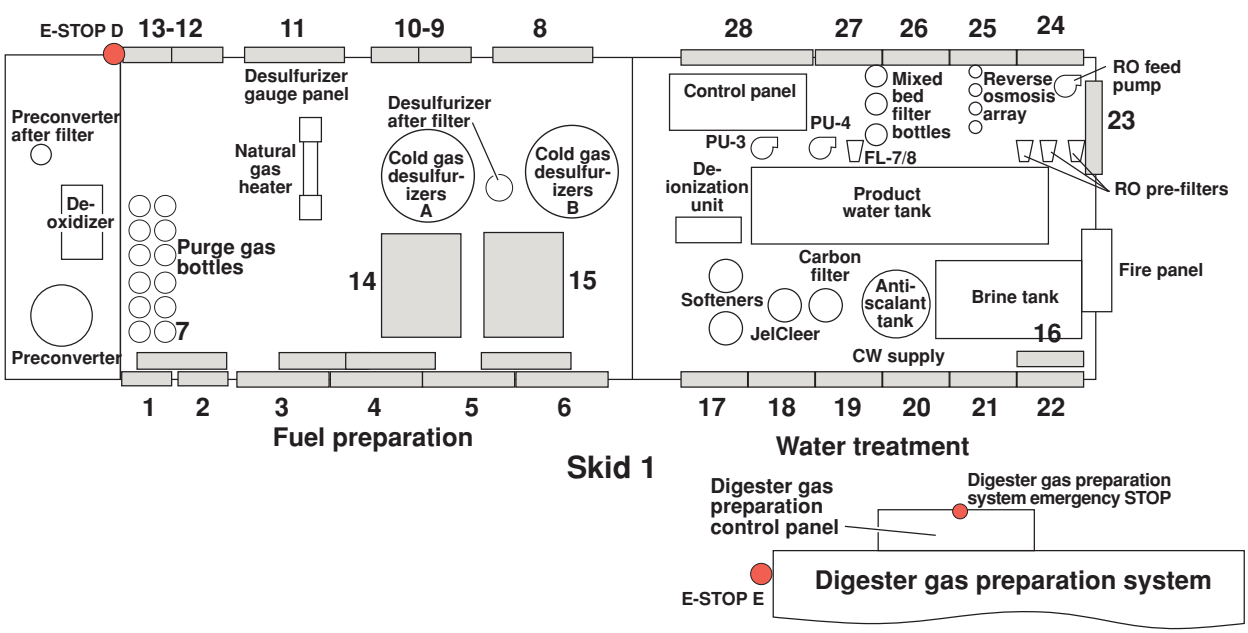
NOTE: The waste heat recovery system is not covered in this manual.



Fuel cell stack module and electrical conditioning skid



Skid 2



1.11 Layout of the Digester Gas Preparations System

Before the raw digester gas can be used for the chemical reaction inside the fuel cell it must be scrubbed and compressed. The digester gas preparation system is housed in the northeast corner of the fuel cell facility.

Emergency monitoring

The digester gas preparation system is monitored for hydrogen sulfide (H2S) or toxic gas and fire.

WARNING

Personal H2S monitors must be carried in the digester gas preparation area if the digester gas preparation system is operating.

There are two hydrogen sulfide or toxic gas beacons (flashing yellow) in this area, one on the north west corner of the compressor shed and one between the SulfaTreat bed and the digester gas polisher.

There is also a yellow beacon on the water treatment system booster pump shed, however this only indicates the loss of the booster pumps, which will shut down the fuel cell.

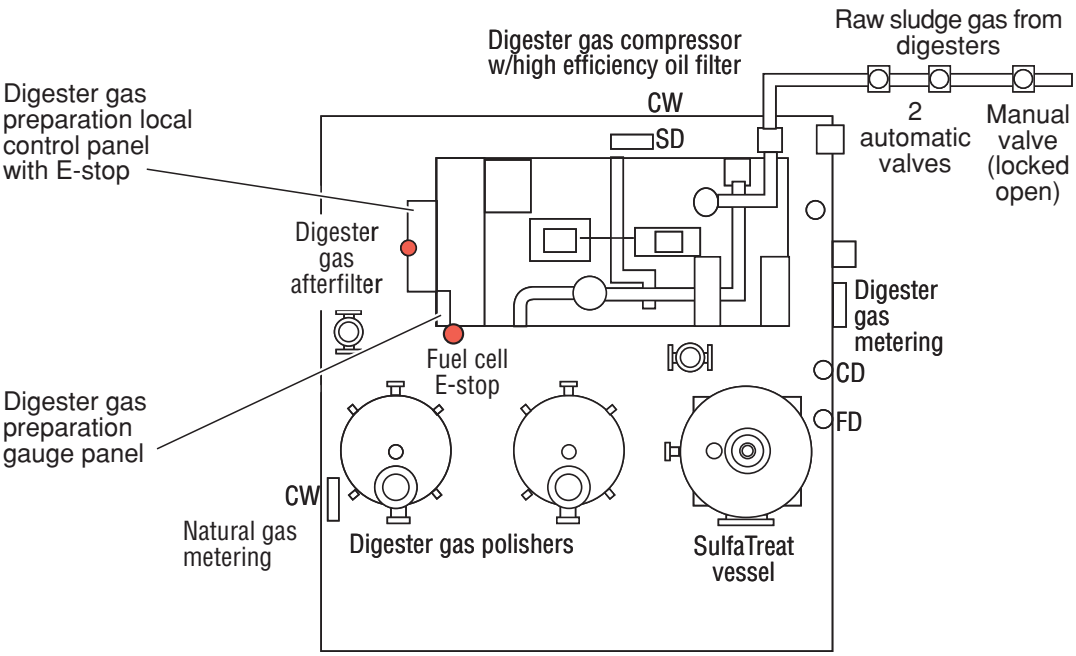
There is one fire alarm beacon (flashing red) and a horn in this area. There is a fire pull and a system emergency stop button located on the southwest corner of the compressor enclosure. There is a local system emergency stop button on the digester gas preparation system panel.

Equipment

The digester gas skid includes the digester gas polisher, SulfaTreat vessel, digester gas high performance oil filter, a gas compressor, an after-filter, the digester gas flow element, and the system controls. The digester gas preparation system panel is mounted on the west side of the enclosure. A gauge panel for the enclosure is mounted on the southwest corner of the enclosure, it is mounted behind a window so that the gauges are visible without entering the enclosure.

DANGER

The manual raw digester gas supply isolation valve must remain open because it provides a relief path for the relief valve discharge which is plumbed in betwee the manual valve and the two automatic isolation valves.



Digester gas preparation facility

Digester gas preparation vessels

Raw digester gas supply isolation valves

SECTION 2
Checking the Fuel Cell

2.1 Checking the Fuel Cell System 2-2
2.2 Checking Skid 1, Water Treatment and Fuel Preparation 2-4
2.3 Checking Skid 2, the AGO Skid and the Startup Skid 2-10
2.4 Checking the Electrical Balance of Plant and Fuel Cell Stack Module 2-14
2.5 Checking the Digester Gas Preparation Skid 2-16
2.6 Checking the Fuel Cell System Quarterly 2-18

2.1 Checking the Fuel Cell System

The fuel cell system has potential combustible and poisonous gas, electrical, thermal, and other types of hazards that you should be aware of in order to work safely in the area. King County only has limited responsibilities for providing materials to run the fuel cell system. To limit our liability, you must be aware of these responsibilities as well as the responsibilities of the FuelCell Energy (FCE) operator. The FCE operator must be onsite during all fuel cell plant startups.

Safety

The fuel cell system has the following built-in safety features:

- The fuel cell stack module is structurally designed to withstand pressure spikes induced by internal fires.
- Systems with methane are monitored for fire, and combustible gas. Leaks of treated digester gas downstream from the desulferizer and natural gas/scrubbed digester gas downstream from the cold gas desulfurizers are not be detectable by smell. Therefore, lower explosive limit (LEL) gas detectors are installed to detect methane gas and fuel gas leaks in the fuel gas preparation system and digester gas conditioning system.
- Carbon monoxide is present in significant concentrations in the anode exhaust gas and is highly poisonous. LEL gas detectors are installed to detect carbon monoxide leaks in the anode exhaust gas piping.
- Hydrogen sulfide (H2S) smells like rotten eggs, it is highly poisonous and may be contained within digester gas so H2S levels are monitored in the digester gas preparation enclosure. Because H2S is being removed from the methane in this area, personal H2S monitors must be worn by anyone entering the digester gas preparation area, there are no exceptions.

For more information on the various safety devices see the overview of the systems controls in section 5.

Electrical classification

The onsite fuel cell equipment and controls are designed for electrical classification per code (Class 1, Division 2, Groups B and D)[1].

The fuel preparation and water treatment system section of skid 1 is a NEMA, Div. 2 enclosure. Use non-sparking brass tools and properly rated electrical equipment when performing maintenance in this enclosure.

King County responsibilities

King County is responsible for providing nitrogen bottles, city water, digester gas, and “pipeline quality” scrubbed digester gas. The water and scrubbed gas shutoffs are on the east side of the water and fuel preparation enclosure, Skid 1.

To prevent county liability in the case of an accident, do not provide any other items than those listed to either the contractor or FuelCell Energy personnel.

Emergency shutdown responsibility. Any one can shutdown the fuel cell system in an emergency. There are five places to shutdown the fuel cell system. There are also emergency shutdowns for the AGO burner system, instrument air system, and digester gas preparations system. The system can also be shut down from the DCS computer using the red STOP button available from most computer screens. The digester gas supply can also be isolated locally with a manual valve and remotely next to the waste gas burner enclosure. For exact locations of the emergency stop buttons see *Section 1, Introduction to the Fuel Cell Systems* or *Section 3, Safety*. If possible contact the FCE operator before shutting down the system.

DANGERS

Natural gas is present. No smoking, sparks, or open flames are permitted any where in the area.

Desulfurized natural gas has no odor. Use extreme caution when performing maintenance activities.

1. Preliminary, based on DFC® Process Design Guide

DANGERS

Do not open the water treatment system panels while fuel preparation access panels are removed and natural gas is flowing through the system.

The fuel preparation enclosure is a NEMA, Div. 2 enclosure. Use non-sparking brass tools and properly rated electrical equipment when performing maintenance in this enclosure.

Use standard safety procedures for handling and storing compressed gas when handling the nitrogen cylinders.

Lethal AC and DC voltages are present behind hinged and removable panels. Do not open or remove the panels unless you are a trained electrician and are wearing proper personal protective equipment (PPE). All panels must be locked in place unless they are being serviced.

Never stand on or store materials on roof top space.

Use fall protection as required.

Hot surfaces are present throughout the area. Do not touch anything unless you are sure it is not hot. Be aware that surfaces that are warm to the touch can suddenly heat up to dangerous levels.

Read and pay attention to all warning labels.

Do not enter any enclosure unless you have been trained and are wearing the proper PPE.

General safety

- Use King County safety procedures for lockout/taggout, fall protection, etc.
- The system is computer-controlled and equipment may start and stop at any time.
- The area around the fuel cell should be kept free of insulating and combustible material.
- Do not block any air intake or discharges or limit their size. Proper ventilation is important for safety and effective operation.
- The fuel cell stack module has current posts that maintain lethal DC voltage even after the power has been disconnected. The voltage will remain until the stack has cooled to the temperature of the outside air.
- The UPS battery still carries a lethal voltage after the plant has been shut down and electrically isolated.

DANGER

If any part of the fuel cell system had been flooded, do not use until it has been inspected by FuelCell Energy.

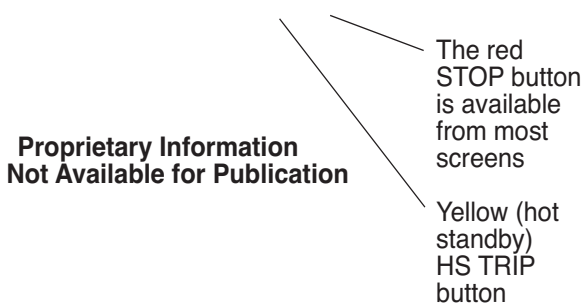
Confined spaces

The fuel preparation, water treatment and digester gas preparation enclosures are permit required confined spaces anytime the fans are not operating, or local monitoring indicates a problem.

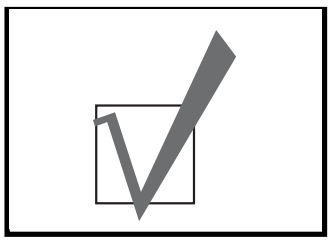
The water tank, fuel cell vessel (stack module), anode gas oxidizer (AGO), and the heat recovery unit are permit required confined spaces.

Hot work

Because of the methane gas throughout the fuel cell area, many items will require a hot work permit in order to make repairs. Consult the hot work permit program manual for requirements before bringing any open flame into the fuel cell area.



Shutdown from DCS



2.2 Checking Skid 1, Water Treatment and Fuel Preparation

The fuel cell system checklists should be completed daily or weekly as indicated. There are several hazards in and around the fuel cell system area, DO NOT perform these tasks unless you have been trained to work in the area and your supervisor has requested that you complete the checklist. This list of routine checklist items is taken from *FuelCell Energy, Inc. DFC 1500 Operations/Maintenance Manual*[1]. Start at panel 19 and 20 in the water treatment enclosure on the east side of the skid, and follow the arrow on the illustration.

DANGER

This checklist is generally performed while the fuel cell is operating. Use extreme caution. DO NOT enter any enclosure without proper authorization, training, and personal protective equipment. Use safety equipment including personal protective equipment and OSHA fall protection equipment as required.

General daily checks for skid 1

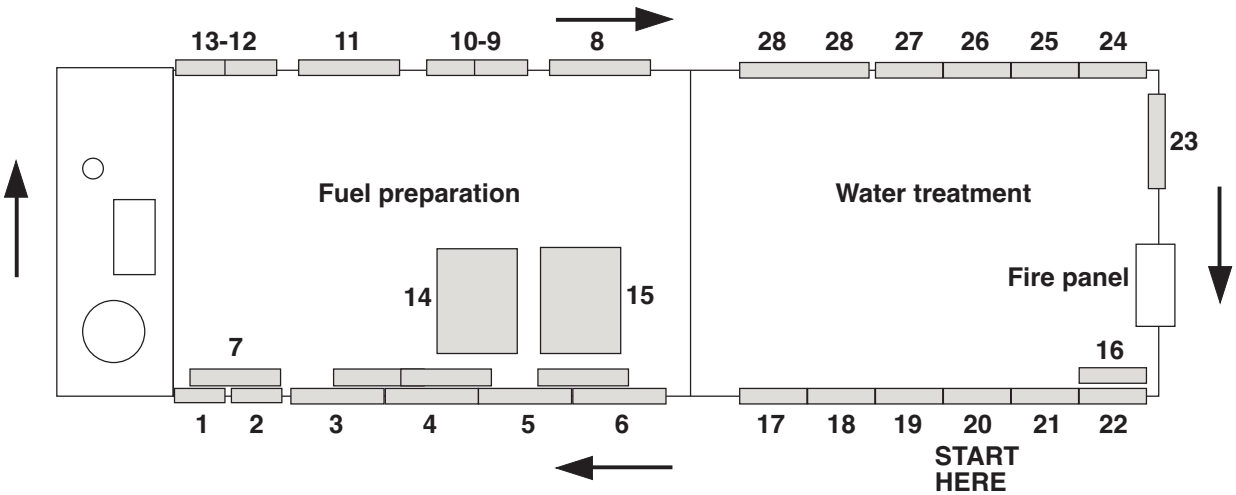
Most equipment is located inside the enclosure accessible through removable panel doors. The panels weigh between 40 and 60 pounds and are awkward to handle. Use proper lifting procedures.

- Check the DCS computer for any fire, LEL, or H2S alarms before entering the area.
- Be sure all ventilation and exhaust airways are not blocked.
- Be sure utility supply valves for gas and water are fully open.
- Check all enclosed areas for moisture, corrosion, abnormal conditions, damage, and foreign objects. Clean the area with a vacuum, if needed.
- Take and record ambient temperature and relative humidity.
- Skid1 has lights. The light switches for the water treatment system compartment and the fuel preparation compartment are inside the compartments behind panels 2, 20, and 27.

NOTE: You do not need to check panels 21 and 22. This area contains the brine storage tank, and is checked from above when panel 16 is removed.

1. **Check panels 17 through 20.**
   Remove the panels. Check each enclosure for moisture, corrosion, abnormal conditions, damage and foreign objects; clean with a vacuum if needed.
2. **In panels 19 and 20, check the antiscalant tank level and mixer operation.**
   Replenish the antiscalant tank if needed.
3. **In panel 18, check the pressure drop on the activated carbon filter.**
   a) Check that the difference between gauges PI-401 and PI-403 reads 5 psid or less.
   b) Record the readings on the city water (CW) supply pressure gauge (PI-401) and the activated carbon filter outlet pressure gauge (PI-403).
   c) Calculate and record the differential pressure across the activated carbon filter (PI-401 – PI-403)
4. **In panel 18, check the pressure drop on the multimedia filter.**
   a) Check that difference between gauges PI-403 and PI-405 reads 5 psid or less.
   b) Record the reading of multimedia filter outlet pressure gauge (PI-405).
   c) PI-403 was recorded previously in step 4.

1. NOTE: The following appear in the FCE maintenance manual but have been remove by review.
Deoxidizer inlet temperature; temperature saved by DCS computer.
Preconverter afterfilter differential pressure gauge (PDI-124) (filter removed) (TI-247) super heater inlet temp remove after testing



d) Calculate and record the differential pressure across the multimedia filter (PI-403 – PI-405)

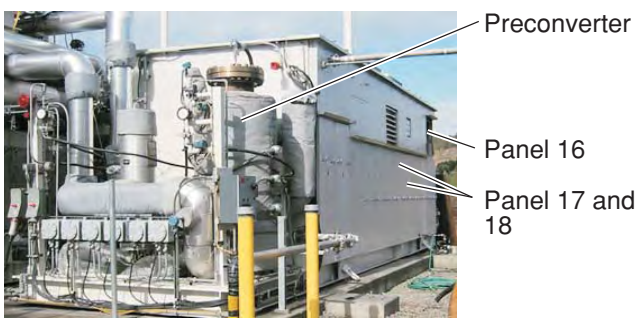
5. In panel 17, on the water softeners, check pressure drop on the water softeners.

a) Check that the difference between gauges PI-405 and PI-409 reads 5 psid or less.

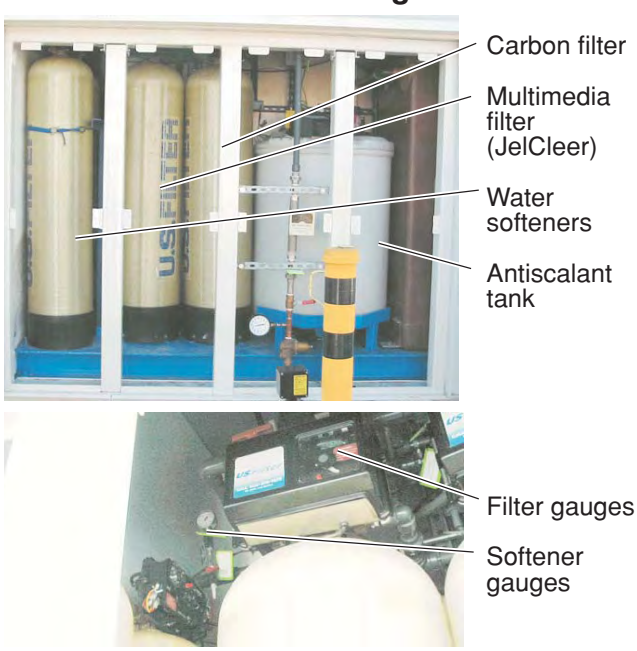
b) Calculate and record the differential pressure across the water softener (PI-405 – PI-409)

c) Record which water softener is on line.

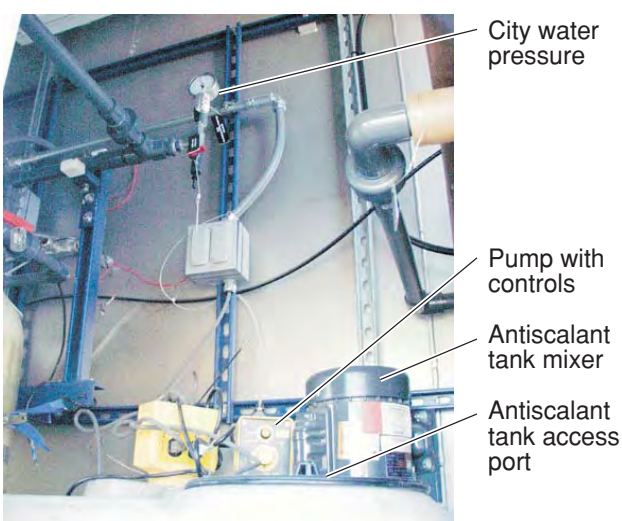
6. Reinstall panels 17 through 20.



Panels 16 through 18



Panel 17-20 checking the filters, water softeners, and antiscalant tank



Panel 19-20

Checking the fuel preparation area

DANGER

Be sure that all water treatment system panels are closed and locked in place before removing any fuel preparation enclosure panels.

Before removing any fuel preparation enclosure panels verify no one is smoking and that there are no sparks or open flames in the area.

NOTE: You do not have to check panel 6. The desulfurizer vessel B is checked from panel 5.

7. Check panel 5.

a) Remove panel 5. Check the enclosure for moisture, corrosion, abnormal conditions, damage and foreign objects; clean with a non-sparking vacuum cleaner, if needed.

b) Record the reading on desulfurizer vent line pressure gauge (PI108)

c) Reinstall panel 5.

8. Check panels 4, 3, 2, and 1.

a) Remove the panels.

b) Check the enclosure for moisture, corrosion, abnormal conditions, damage and foreign objects; clean with a vacuum cleaner, if needed.

NOTE: The nitrogen six-packs are behind panels 1 and 2. Panels 3 and 4 provide access to the fuel preparation enclosure.

9. Record the following reading from the preconverter;it is located on the open end.
Record the readings from the following:

a) Preconverter jacket heater temperature from the control panel

b) Fuel deoxidizer pressure differential gauge (PDI-121)

c) Deoxidizer preconverter differential pressure gauge (PDI-122)

NOTE: You do not have to check panels 12 and 13.

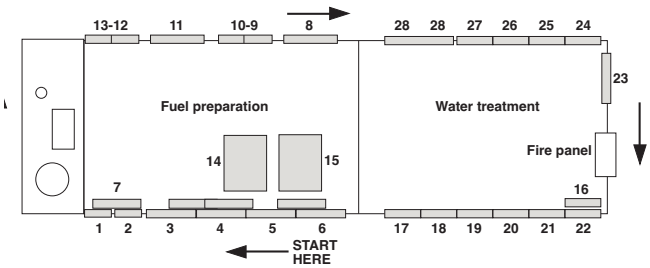
10. Check panel 11 and record the readings on the gas gauges.

a) Open the panel and record the readings from the following:

- Cold gas desulfurizer A differential pressure gauge (PDI-104)
- Cold gas desulfurizer B differential pressure gauge (PDI-106)
- Desulfurizer afterfilter differential pressure gauge (PDI-109)
- Fuel supply to cold gas desulfurizers A/B gauge (PI-100)
- Cold gas desulfurizer A outlet differential pressure gauge (PI-107)
- Cold gas desulfurizer B outlet pressure gauge (PI-110)
- The nitrogen cylinder supply pressure (six-pack 1) (PI-187, rapid purge bottle) and six-pack 2 (PI-163, bleed purge bottle pressure)
- The nitrogen purge pressure to the heat recovery unit (PI-173, rapid purge supply pressure)
- The nitrogen supply pressure to the fuel cell stack (PI-176, bleed purge supply pressure)

b) Check that all the sample port caps are in place and all sample port isolation valves are closed.

c) Close the panel.



Desuferizer vent line pressure gauge (PI-108)

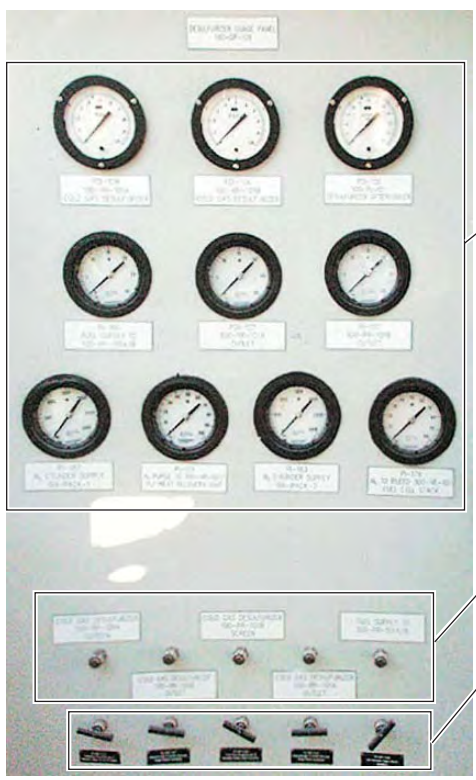
Panel 5-6

Preconverter PDI-122

Deoxidizer PDI-121

Jacket heater control panel

Preconverter



Pressure gauges

Sample ports

Sample port isolation valves

Panel 11, gas gauges

Finishing the water treatment area

11. Check panels 28, the manual controls, PLC, and the DI (deionization) pumps.

a) Open the hinged panel 28.

b) Check PLC screen for anything abnormal.

c) Clear any alarm conditions, acknowledge and clear any alarms.

d) Record the discharge pressure reading on which ever DI system is in the duty position. (PU-3 discharge pressure at PI-447 or PU-4 discharge pressure at PI-448).

e) Close and latch the panel.

12. Check panel 25, the reverse osmosis (RO) prefilters FL-3 through FL-5. Record the recycle loop flow rate.

Check pressure drop across the prefilters using gauges PI-409 and PI-414. Replace filters when pressure drop reaches 10 psig.

a) Remove the panel.

b) Record the readings on:

- RO prefilter inlet pressure gauge (PI-409)
- RO inlet pressure gauge (PI-414)
- RO booster pump supply pressure gauge (PI-416)
- RO booster pump outlet pressure gauge (PI-420).

c) Calculate and record the differential pressure across the RO prefilters. (PI-409 –PI-414)

d) Record the reading on recycle loop flow indicator (FI-426).

e) Reinstall the panel.

13. Check panel 23, the reverse osmosis booster pump (PU-2).

Weekly

1. In panel 28, rotate the DI (deionization) pump duty.

a) Change which DI pump (PU-3 or PU-4) is the duty pump.

CAUTION

Follow this procedure exactly or water flow to the fuel cell humidifier may be interrupted causing the fuel cell to trip on low steam-to-carbon ratio.

1. Turn the off-line pump from AUTO to HAND.
2. Turn the on-line pump from AUTO to HAND.
3. Rotate DUTY SELECTOR SWITCH to OPPOSITE PUMP.
4. Turn the pump that is now on-line from HAND to AUTO.
5. Turn the pump that is now off-line from HAND to AUTO.

2. Check panels 26 and 27, record the differential pressure of mixed bed filters FL-6 and FL-7, and the discharge pressure on product water pump PU-3/PU-4, which ever is running.

a) Remove the panels.

b) Check the enclosure for moisture, corrosion, abnormal conditions, damage and foreign objects; clean with a vacuum cleaner, if needed.

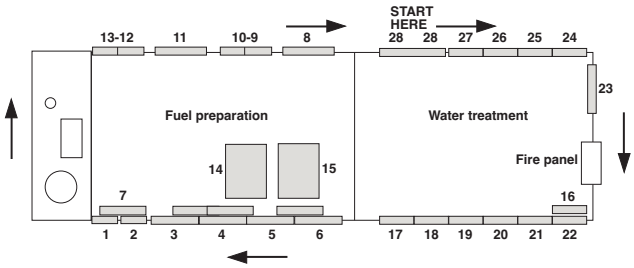
c) Record the readings on:

- FL-6 inlet pressure gauge (PI-440)
- FL-6 outlet pressure gauge (PI-441)

d) Calculate and record the differential pressure across mixed bed filter FL-6. (PI-440 – PI-441).

e) Record the reading on PU-3/PU-4 water treatment system discharge pressure (PI-447/PI-448), depending on which pump is on-line at the time.

f) Reinstall the panels.



PLC PanelView OIU

Process indicators

Manual controls

DI transfer pump PU-4

DI transfer pump PU-3

Panel 28-29

FL-6 inlet pressure gauge (PI-440)

FL-6 outlet pressure gauge (PI-441)

Panel 26-27 FL-6 pressure gauges

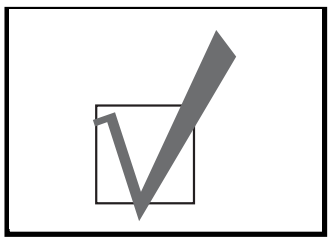
Recycle loop flow indicator

Panel 25, recycle loop flow indicator

Reverse osmosis booster pump (PU-2)

Panel 24, RO booster pump PU-2

Reference



2.3 Checking Skid 2, the AGO Skid and the Startup Skid

You will check side A, B, and C of skid 2 in that order. The skid houses the anode gas oxidizer (AGO) burner. Be careful in this area because many of the surfaces are hot or if warm can suddenly become dangerously hot. All ventilation intakes and discharges must be kept clear at all times.

Checking side A

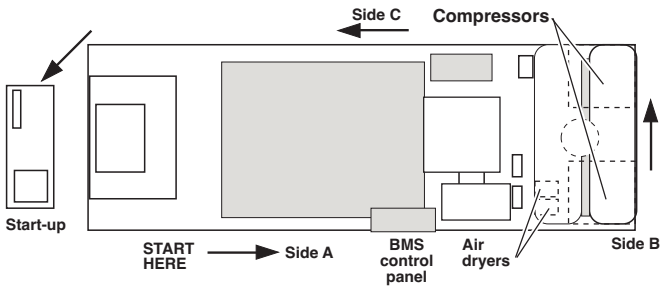
WARNING

This area has hot surfaces.

1. **Check the area.**
   Check all the areas for moisture, corrosion, abnormal conditions, damage and foreign objects; clean with a vacuum cleaner, if needed.
2. **Check the instrument air (IA) compressor A intake filter.**
   Replace at 3 months or when clogged.
3. **Take and record readings from the following:**
   - Instrument air header pressure gauge (P1-262)
   - Desulfurized natural gas (methane) differential (NGD) pressure to AGO pilot gauge (PI-202)
   - NGD pressure to AGO gauge (PI-211)
   - Air blower discharge pressure gauge (PI-223)
   - IA pressure to AGO pilot gauge (PI-265)
   - Tertiary air pressure gauge (PI-258)
   - Natural gas (NG) supply pressure to main burner (PI-2I6)
4. **Check and record the desiccant status of the IA air dryer 1.**
   Blue is good; pink is saturated and needs troubleshooting or replacing (CD-17).
5. **Record the IA dryer after filter status.**
   Green is good, red needs replacement?
   a) IA air dryer 1 after filter differential pressure gauge (FL-503) (green/red)
   b) IA air dryer 2 after filter differential pressure gauge (FL-504) (green/red)
6. **Check the AGO high pressure blower intake filters.**
   a) Read and record the filter differential pressure.
   b) Replace the filter at 3 months or when clogged.

Checking side B

1. **Check the area.**
   Check all the areas for moisture, corrosion, abnormal conditions, damage and foreign objects; clean with a vacuum cleaner, if needed.



Side A

Manifold just south of BMS control panel

AGO intake filters, IA dryer after-filters and desiccant status and PI-250

Side B

IA compressor system

Checking side C

1. **Check the area.**
   Check all the areas for moisture, corrosion, abnormal conditions, damage and foreign objects; clean with a vacuum cleaner, if needed.

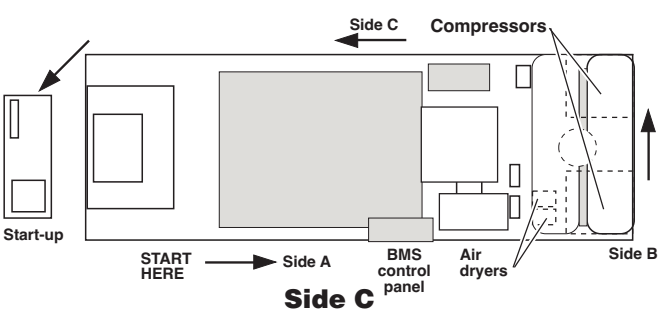
2. **Record the IA dryer pre-filter status.**
   Green is good, red needs replacement?

   a) Record the IA air dryer 1 pre-filter differential pressure gauge (FL-501) (green/red)

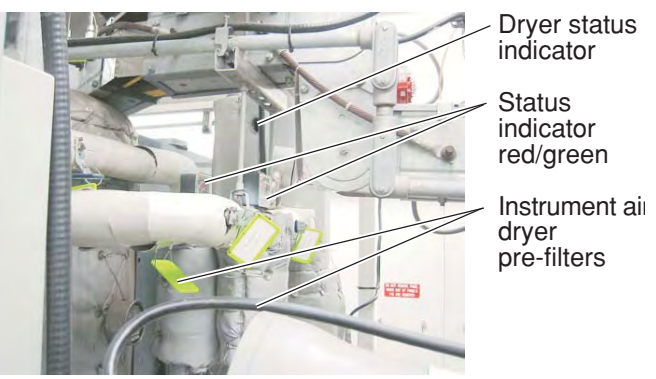
   b) Record the IA air dryer 2 pre-filter differential pressure gauge (FL-502) (green/red).

3. **Check and record the desiccant status of the IA air dryer 2.**
   Blue is good; pink is saturated and needs troubleshooting or replacing (CD-17).

4. **Record readings on:**
   - (PI-250) purge air pressure
   - (PI-225) pilot air pressure
   - (PI-230) primary air pressure
   - (PI-229) secondary air pressure
   - (PI-237) pressure after AGO catalyst
   - (PI-206) natural gas (NG) supply pressure to pilot.



PI-225 Pilot air pressure gauge



Instrument air pre-filters

PI-229/PI-230 AGO blower primary and secondary air pressure

Checking the start-up skid

1. **Check all the areas for moisture, corrosion, abnormal conditions, damage and foreign objects; clean with a vacuum cleaner, if needed.**
2. **If the startup skid is not connected, about every two weeks exercise the blower shaft.**
   a) Remove the cover from the startup blower.
   b) Rotate blower shaft with your hand.
   c) Reinstall the cover.
3. **If the startup skid is connected and running, check and record the readings on gauges PDI-235 and PI-28.**
   - (PDI-235) startup blower differential pressure
   - (PI-280) startup heater pressure.

Startup skid

Reference

2.4 Checking the Electrical Balance of Plant and Fuel Cell Stack Module

This area has some panels that contain 480V equipment. Do not open the panels in this section unless you have been trained to do so. Check the electrical balance of plant (EBOP) enclosure and the surrounding area; clean as needed.

1. Check panel 1.

DANGER

Panel 1 is a 480 volt panel. Do not open it unless you have been trained.

a) Open the panel door.

b) Check all the areas for moisture, corrosion, abnormal conditions, damage and foreign objects; clean with a vacuum cleaner, if needed.

c) Close the panel door.

2. Check panel 2, the DCS computer and interface (future).

a) Open the panel door.

b) Check all the areas for moisture, corrosion, abnormal conditions, damage and foreign objects; clean with a vacuum cleaner, if needed.

c) Check the distributed control system (DCS) interface; report anything abnormal to the site maintenance supervisor.

d) Close the panel door.

3. Check panels 3, 4, 5, and 6.

a) Open the panel door.

b) Check all the areas for moisture, corrosion, abnormal conditions, damage and foreign objects; clean with a vacuum cleaner, if needed.

c) Close the panel door.

4. Check panel 7, this is the power distribution system.

a) Open the panel door.

b) Check all the areas for moisture, corrosion, abnormal conditions, damage and foreign objects; clean with a vacuum cleaner, if needed.

c) Check the inverter breakers, tie breaker, and F60 relay; report anything abnormal to the Site Maintenance Supervisor.

d) Close the panel door.

DANGER

Panel 8 houses the UPS, the UPS battery can maintain a lethal voltage even after a shutdown.

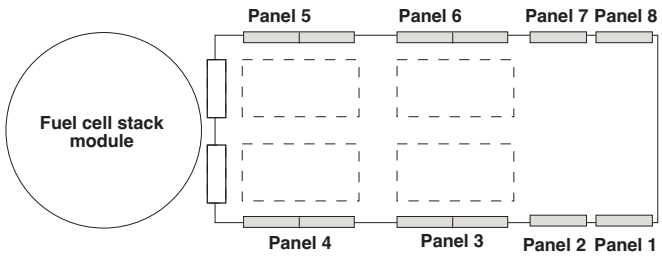
5. Check panel 8.

a) Open panel door.

b) Check all the areas for moisture, corrosion, abnormal conditions, damage and foreign objects; clean with a vacuum cleaner, if needed.

c) Close panel door.

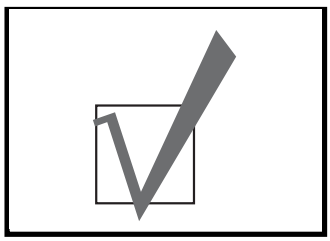
NOTE: The communications bus and UPS are monitored and will alarm if they fail.



Electrical balance of plant enclosure

Electrical balance of plant enclosure

Reference



2.5 Checking the Digester Gas Preparation Skid

The SulfaTreat vessel, a part of the digester gas preparation system, needs to be drained once a day when the system is being used. Alot of the area equipment is heat traced, it is important that the heat tracing system is on and working. The breakers for the heat tracing system are located _____. Local readouts for the scrubbing system should be recorded daily on the checklist. Because of the chance of exposure to hydrogen sulfide in this area a hydrogen sulfide monitor must be carried to complete the checklist.

DANGER

You must test, calibrate, and carry a personal gas monitor for hydrogen sulfide (H2s) in this area. Besure the batteries are fresh.

Digester gas will leak from the SulfaTreat drain valve when it is open.

1. **Drain the SulfaTreat vessel.**
   The SulfaTreat vessel is equipped with a manual drain for condensation. The vessel should be drained once a day. Crack open the manual valve (V8027), when the water stops draining close the valve.

2. **Check the heat tracing.**
   The temperature gauges at the following locations indicate the heat trace system is working:

   - Polisher A (1 gauge) and B (2 gauges).
   - Flow meter FE-800 (1 gauge)
   - Manual valve MV-8050 and MV-8052 (1 gauge each)
   - SulfaTreat outlet pipe

3. **Check and record the following local readouts.**
   These gauges are behind glass, on the west wall of the shed in the south corner.

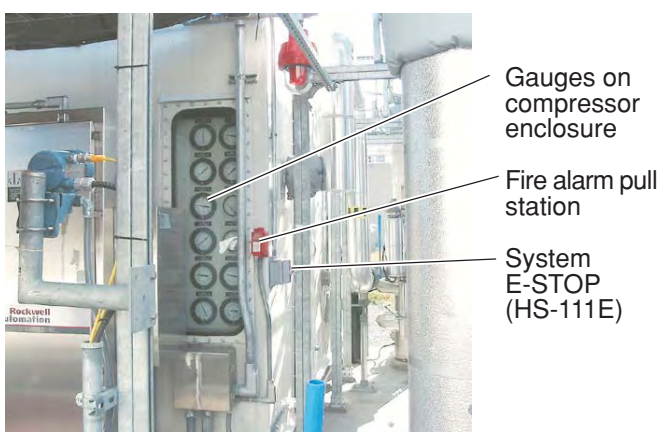
   - Anode digester gas (ADG) SYS INLET PRESSURE, feed knockout (KO) drum pressure (PI-826)
   - ADG INLET GAS TEMPERATURE (TI-810)
   - COMPRESSOR DISCHARGE PRESSURE (PI-830)
   - COMPRESSOR OUTLET GAS TEMPERATURE, ADG temp compressor out (TI-812)
   - COMPRESSOR SUCTION PRESSURE, Feed KO drum pressure out (PI-821)
   - FEED KO DRUM D/P (differential pressure) (PDI-827)
   - ADG SYSTEM OUTLET PRESSURE (PI-823)
   - DISCHARGE KO DRUM D/P (PDI-828)
   - ADG SYSTEM OUTLET GAS TEMPERATURE (after KO drum) (TI-811)
   - COMPRESSOR COOLING WATER OUTLET TEMP (TI-832)
   - COUPLING SEAL POT NITROGEN PRESSURE (PI-833)
   - COOLING WATER SUPPLY TEMPERATURE (TI-814)
   - Oil Filter differential pressure (PDI-810)

   These gauges are located on the piping south of the DG gas preparation enclosure.

   - SulfaTreat vessel differential pressure (DPI-822)
   - SulfaTreat outlet pressure (PI-820)
   - Digester gas vent pressure (PI-817)
   - Polisher A differential pressure (PDI-804)
   - Polisher B differential pressure (PDI-806)
   - Polisher A pressure (PI-807)
   - Polisher B pressure (PI-809)
   - Polisher vent leak check (PI-808)
   - Digester gas afterfilter differential pressure (PDI-812)

Digester gas preparation valve manifold

Behind digester gas polisher



Gauges on southwest corner of enclosure

NOTE: The compressor speed is monitored from the DCS computer.

Overhead and behind SulfaTreat vessel

Behind post gauges PI 806 and PI 808

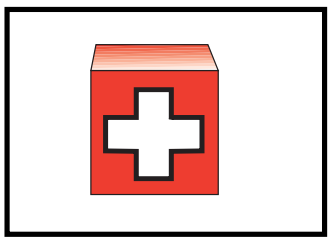
2.6 Checking the Fuel Cell System Quarterly

There are numerous items that must be serviced quarterly by maintenance, for a complete list see the FuelCell Energy, Inc. maintenance manual. The manual also contains the instructions, safety requirements and the locations of the equipment. If other tasks need to be added, they will be added here.

Reference

SECTION 3
Safety

3.1 Fuel Cell Safety Considerations 3-2
3.2 Emergency Shutdown and Alarm Beacon Locations 3-4



3.1 Fuel Cell Safety Considerations

The fuel cell system has potential combustible and poisonous gas, electrical, thermal, and other types of hazards that you should be aware of in order to work safely in the area. King County only has limited responsibilities for providing materials to run the fuel cell system. To limit our liability, you must be aware of these responsibilities as well as the responsibilities of the FuelCell Energy (FCE) operator. The FCE operator must be onsite during all fuel cell plant startups.

Safety

The fuel cell system has the following built-in safety features:

- The fuel cell stack module is structurally designed to withstand pressure spikes induced by internal fires.
- Systems with methane are monitored for fire, and combustible gas. Leaks of treated digester gas downstream from the desulferizer and natural gas/scrubbed digester gas downstream from the cold gas desulfurizers are not be detectable by smell. Therefore, lower explosive limit (LEL) gas detectors are installed to detect methane gas and fuel gas leaks in the fuel gas preparation system and digester gas conditioning system.
- Carbon monoxide is present in significant concentrations in the anode exhaust gas and is highly poisonous. LEL gas detectors are installed to detect carbon monoxide leaks the anode exhaust gas piping.
- Hydrogen sulfide (H2S) smells like rotten eggs, it is highly poisonous and may be contained within digester gas so H2S levels are monitored in the digester gas preparation enclosure. Because H2S is being removed from the methane in this area, personal H2S monitors must be worn by anyone entering the digester gas preparation area, there are no exceptions.

For more information on the various safety devices see the overview of the systems controls in section 5.

Electrical classification

The onsite fuel cell equipment and controls are designed for electrical classification per code (Class 1, Division 2, Groups B and D)[1].

The fuel preparation and water treatment system section of skid 1 is a NEMA, Div. 2 enclosure. Use non-sparking brass tools and properly rated electrical equipment when performing maintenance in this enclosure.

King County responsibilities

King County is responsible for providing nitrogen bottles, city water, digester gas, and “pipeline quality” scrubbed digester gas. The water and scrubbed gas shutoffs are on the east side of the water and fuel preparation enclosure, Skid 1.

To prevent county liability in the case of an accident, do not provide any other items than those listed to either the contractor or FuelCell Energy personnel.

Emergency shutdown responsibility. Any one can shutdown the fuel cell system in an emergency. There are five places to shutdown the fuel cell system. There are also emergency shutdowns for the AGO burner system, instrument air system, and digester gas preparations system. The system can also be shut down from the DCS computer using the red STOP button available from most computer screens. The digester gas supply can also be isolated locally with a manual valve and remotely next to the waste gas burner enclosure. For exact locations of the emergency stop buttons see *Section 1, Introduction to the Fuel Cell Systems* or *Section 3, Safety*. If possible contact the FCE operator before shutting down the system.

DANGERS

Natural gas is present. No smoking, sparks, or open flames are permittend any where in the area.

1. Preliminary, based on DFC® Process Design Guide

DANGERS

Desulfurized natural gas has no odor. Use extreme caution when performing maintenance activities.

Do not open the water treatment system panels while fuel preparation access panels are removed and natural gas is flowing through the system.

The fuel preparation enclosure is a NEMA, Div. 2 enclosure. Use non-sparking brass tools and properly rated electrical equipment when performing maintenance in this enclosure.

Use standard safety procedures for handling and storing compressed gas when handling the nitrogen cylinders.

Lethal AC and DC voltages are present behind hinged and removable panels. Do not open or remove the panels unless you are a trained electrician and are wearing proper personal protective equipment (PPE). All panels must be locked in place unless they are being serviced.

Never stand on or store materials on roof top space.

Use fall protection as required.

Hot surfaces are present throughout the area. Do not touch anything unless you are sure it is not hot. Be aware that surfaces that are warm to the touch can suddenly heat up to dangerous levels.

Read and pay attention to all warning labels.

Do not enter any enclosure unless you have been trained and are wearing the proper PPE.

General safety

- Use King County safety procedures for lockout/taggout, fall protection, etc.
- The system is computer-controlled and equipment may start and stop at any time.
- The area around the fuel cell should be kept free of insulating and combustible material.
- Do not block any air intake or discharges or limit their size. Proper ventilation is important for safety and effective operation.
- The fuel cell stack module has current posts that maintain lethal DC voltage even after the power has been disconnected. The voltage will remain until the stack has cooled to the temperature of the outside air.
- The UPS battery still carries a lethal voltage after the plant has been shut down and electrically isolated.

WARNING

If any part of the fuel cell system had been flooded, do not use until it has been inspected by FuelCell Energy.

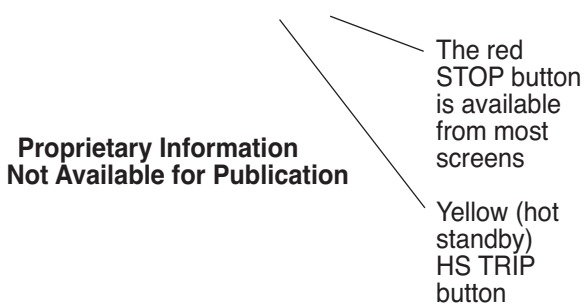
Confined spaces

The fuel preparation, water treatment and digester gas preparation enclosures are permit required confined spaces anytime the fans are not operating, or local monitoring indicates a problem.

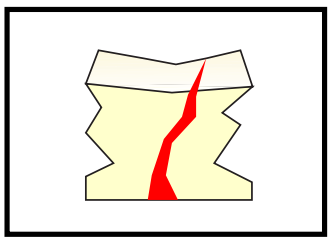
The water tank, fuel cell vessel (stack module), anode gas oxidizer (AGO), and the heat recovery unit are permit required confined spaces.

Hot work

Because of the methane gas throughout the fuel cell area, many items will require a hot work permit in order to make repairs. Consult the hot work permit program manual for requirements before bringing any open flame into the fuel cell area.



Shutdown from DCS



3.2 Emergency Shutdown and Alarm Beacon Locations

There are six system wide emergency shutdown buttons in the fuel cell area. There is also a system wide emergency STOP button and a HS TRIP or hot standby trip button on every base screen on the DCS computer. The instrument air compressors, the AGO burner management system, and the digester gas preparation system have local system emergency stop buttons. Know where each of these buttons is located. Anyone can shutdown the system in an emergency. The fire panel will shutdown the system for any safety related alarm using the DCS. The area is monitored for fire, toxic gas, and LEL, each alarm triggers a flashing light and horn. Red flashing lights indicate fire, white flashing lights indicate LEL, and yellow flashing lights indicate toxic gas or hydrogen sulfide (H2S). Toxic gas meters must also be carried by anyone entering the digester gas preparation area.

Fuel preparation enclosure

Inside fuel preparation enclosure

Scrubbed gas (methane) shutoff valve

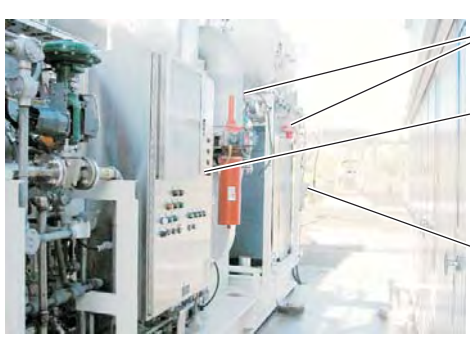
Remote scrubbed gas shutoff valves

Electrical balance of plant (EBOP) E-stops

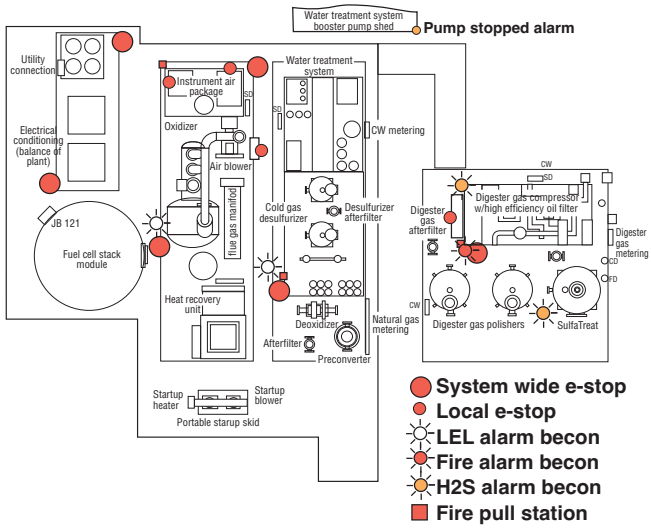
Raw digester gas automatic shutoff valve

Digester gas preparation control panel

Digester gas preparation toxic gas beacon



AGO burner control panel



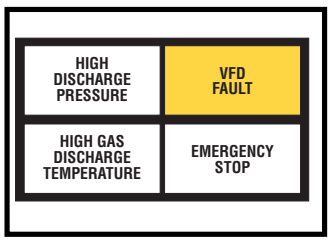
Shutdown locator

EBOP enclosure

Fuel preparion enclosure

SECTION 4
Alarms

4.1 Fuel Cell System Process Halts 4-2
4.2 Fuel Cell System Shutdowns 4-4
4.3 Fuel Cell Alarms 4-6
4.4 Local System Alarms 4-16



4.1 Fuel Cell System Process Halts

The fuel cell system uses what FuelCell Energy, Inc. calls plant protective response (PPR) for alarm responses. The responses, listed in order of increasing severity, include a heatup ramp hold, a reduced kW production step down, a hot standby step down, and a system shutdown.

Heatup ramp hold

During the four stage system heatup, if an alarm occurs or permissive is not met, the oxidizer effluent temperature ramp up is halted and the temperature is held constant. If the problem clears, the temperature ramp up resumes, and the startup will continue until the hot standby or power generation stage is reached.

NOTE: You can manually halt the oxidizer effluent temperature ramp hold from DCS at any time.

Heatup 1 halts

Alarms conditions that halt a heatup 1:

- Manual ramp pause
- Plant master pause
- Hi cell differential temperature (TDI-218)
- Hi differential pressure cathode exhaust to anode exhaust (PDI-254)
- Hi differential pressure cathode inlet to cathode exhaust (PDI-255)
- N2 purge valve open (XV-191)
- N2 bleed valve to cell open (XV-280)
- N2 bleed valve to AGO open (VX-282)

Heatup 2 through 4 halts

Alarms conditions that halt heatup 2 through heatup 4. During this phase of heatup there are two ramp ups happening, one is the cathode inlet temperature (TY-238B) and other is the AGO catalyst (TY-244C).

Cathode inlet temperature ramp up (TY-238B). Alarms that halt the cathode inlet temperature ramp up (TY-238B)

Any alarm that will halt a heatup 1:

- Manual ramp pause
- Plant master pause
- Hi cell differential temperature (TDI-218)
- Hi differential pressure cathode exhaust to anode exhaust (PDI-254)
- Hi differential pressure cathode inlet to cathode exhaust (PDI-255)
- N2 purge valve open (XV-191)
- N2 bleed valve to cell open (XV-280)
- N2 bleed valve to AGO open (VX-282)

Also the following alarms

- TC-238 is >700°F and gas is not enabled
- O2 analyzer pressure valve bad (AI-100A)
- AGO common trouble (UA-201)
- UPS common trouble (UA-352)
- Water treatment common trouble (UA-406)
- N2 bleed valve to cathode open (XV-284)

AGO catalyst ramp up (TY-244C). Alarms that halt the AGO catalyst ramp up (TY-244C)

- Manual ramp pause
- Plant master pause
- Hi differential pressure cathode exhaust to anode exhaust (PDI-254)
- Hi differential pressure cathode inlet to cathode exhaust (PDI-255)
- O2 analyzer pressure valve bad (AI-100A)
- AGO common trouble (UA-201)
- UPS common trouble (UA-352)
- Water treatment common trouble (UA-406)
- N2 purge valve open (XV-191)
- N2 bleed valve to cell open (XV-280)
- N2 bleed valve to AGO open (VX-282)
- N2 bleed valve to cathode open (XV-284)
- Temperature controller TC-245 not in cascade mode

Reduced kW ramp down

If the alarms below register when the fuel cell system is connected to a grid and power is being

generated, the plant power output will be ramped down. This is a reduced kW ramp down. If these conditions get worse or time out after a reduced kW ramp down has been completed, a hot standby step down is started.

- Fuel humidifier outlet low temperature (TI-121)
- Oxidizer effluent high temperature (TIC-238)
- Anode outlet-to-cathode high differential pressure (PDI-254)
- DC current differential high (II-310)

Hot standby step down

If the alarm that caused the hot standby step down gets worse or times out, the plant power output is stopped and the system is put in hot standby. Electric power generation is stopped and the fuel gas, treated water and air flow controls are set for Hot Standby operation.

These alarms cause a hot standby step down:

- Preconverter low low inlet temperature (TC-120)
- Preconverter differential temperature HIHI (TDI-140)
- Fuel humidifier outlet low low (TI-121) or high high temperature
- Manual hot standby trip (HS TRIP)
- Stack current deviation high (II-310)
- Low low cell voltage deviation
- Small group low low cell voltage
- DC power conductor blown fuse stack 1/2/3/4
- Power cell stack (PCS) tripped (UA-350/ UA-351)
- PCS communication failure
- Low digester gas supply pressure (PAL-836)

NOTE: You can manually perform a hot standby step down from the DCS at any time.

Emergency shutdowns, fire and gas alarms

To view and reset the various plant shutdowns and system trips see the shutdowns screen (KING COUNTY EMERGENCY SHUTOWNS, FIRE AND GAS ALARM screen). This lists the plant shutdowns, emergency shutdown (SD) hand switches (HS), reduced power trips and hot standby trips.

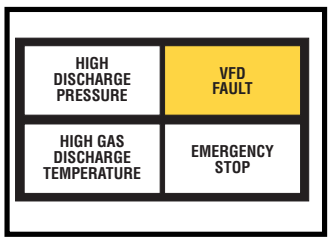
Resetting a shutdown. To reset a plant shutdown, press the RESET switch (HS-112) in the EBOP door panel 2. This must be done before the plant can be restarted.

Proprietary Information
Not Available for Publication

Plant shutdown screen

Cathode inlet temperature ramp holds

AGO catalyst temperature ramp holds



4.2 Fuel Cell System Shutdowns

Any condition that could damage the fuel cell stack or other system equipment causes a full plant shutdown and nitrogen purge. The plant shuts down to one of three levels depending on the problem. These levels include shutdown with auxiliary power available, shutdown with no auxiliary power available and the computer on UPS power, or shutdown with computer failure. All shutdowns are manually reset. Once the fuel cell system has completed cooldowns 1 through 3 the fuel cell is idle.

The off spec gas alarm is also noted by the system but because the system can run on off spec gas, it will continue to operate. The fuel cell cannot automatically switch between digester gas mode and natural gas mode. A digester gas conditioning system trip or a low-low digester gas pressure alarm will shutdown the plant, if the plant is in digester gas mode.

Shutdown with power available

If the plant shuts down with auxiliary power available, the following occurs:

- XV-820A & B closed
- XV-103A & B closed
- The oxidizer and air blower stop
- The fuel gas flow control valve FV-117 or FV-800 (whichever is open) closes
- The treated water flow control valve FV-131 closes
- Air blower discharge block valve XV-241 closes.
- Anode exhaust vent valve (XV-260) opens after 10 minutes and then exhaust gas block valve XV-262 is closed.
- The oxidant bypass valve HV-240 is closed.
- Heat recovery unit (HRU) fuel humidifier dampers TV-120A and TV-120B are closed to minimize air intrusion, but are not designed to maintain a gas tight seal.

The DCS then initiates a slow nitrogen bleed (about 1 scfm) into the stack module anode fuel gas inlet piping and oxidant inlet piping by opening bleed nitrogen valves XV-280 and XV-284.

The slow nitrogen bleeds are introduced into the anodes/cathodes to compensate for gas contraction and prevent air intrusion into the stack module as the module cools. Gas exiting the anodes is vented to the atmosphere through the anode exhaust vent and gas exiting the cathodes will pass through the HRU and the HRU fuel humidifier damper valves to the atmosphere.

The slow nitrogen bleeds continue until the bleed nitrogen supply pressure has dropped to ambient pressure.

XV-280 and XV-284 must be closed before the next startup of the plant.

When the fuel cell median collector temperature drops (TI-XXX) drops to < 650°F, the DCS will initiate a fast nitrogen purge by opening nitrogen purge valve XV-191 and XV-282. The purge flushes fuel gas out of the fuel gas preparation system to prevent nickel carbonyl formation. The purge flow of 100 scfm will last until the nitrogen bottle pressure is depleted.

XV-282 and XV-191 must be closed before the next startup of the plant.

Shutdown with no power available, DCS on UPS

The UPS is large enough to support computer operation for 30 minutes. The instrument air receiver can provide 20 to 30 minutes of instrument air. The shutdown with power available sequencing is used until the system starts to run out of instrument air or the computer fails.

So first the plant does a shutdown with power available and the slow nitrogen bleeds into the stack module are carried out. Then, after about 25 minutes, the nitrogen fast purge valves XV-191 and XV-282 open when either power or instrument air pressure is lost.

Plant shutdown due to computer failure

All valves immediately go into their fail positions.

The following valves fail closed:

- Natural gas supply isolation valves XV-103 A and B
- Digester gas supply isolation valve XV-820 A and B
- Fuel gas flow control valves FV-117 or FV-800 (whichever was open)
- Water flow control valve FV-131
- Anode fuel gas inlet valve XV-247A
- HRU fuel humidifier damper valves TV-120A and B
- Air blower discharge valve XV-241.

The following valves fail open:

- Fuel gas vent valve XV-247B
- Anode exhaust gas vent valve XV-260
- Nitrogen purge valves XV-191 and XV-282
- Nitrogen bleed valves XV-280 and XV-284

The following valves remain in the fail-last position (the position they were in at the time of the failure):

- Anode exhaust gas block valve XV-262 (always open unless plant is tripped)
- Oxidant bypass valve HV-240 (normally closed except during restart temperature matching)

Once shut down, nitrogen purging begins:

- Opening XV-191 immediately cause a fast nitrogen purge (50 scfm) of the fuel gas lines, fuel humidifier, deoxidizer, preconverter, and fuel superheater, with the purged gas exiting through XV-247B to the atmosphere.
- Opening XV-282 will cause a fast nitrogen purge (50 scfm) of the anodes to occur, with the purged gas exiting through XV-247B to the atmosphere and through XV-262 to the oxidizer inlet.

NOTE: The fast nitrogen purges will continue until the purge nitrogen bottles are empty.

- Opening XV-280 immediately causes a slow nitrogen bleed (0.1 scfm) and opening XV-284 immediately causes a slow nitrogen bleeds 0.5 scfm) at the stack module anode fuel gas and oxidant inlet piping. The gas exiting the anodes will vent through XV-247B to the atmosphere and through XV-262 to the oxidizer inlet. The gas exiting the cathodes will pass through the HRU and the HRU fuel humidifier damper valves to the atmosphere.

NOTE: These slow nitrogen bleeds will continue until the bleed nitrogen bottles are empty.

Manual plant shutdown

You can manually shut down the plant at any time from DCS, the EMERGENCY STOP buttons on the local control panel, or any of the field-mounted facility shutdown switches.

Resetting a shutdown. To reset a plant shutdown, the RESET switch (HS-112) on the local control panel must be pressed before the plant can be restarted. To reset the hand switches on the DCS, select the RESET button.

Manual shutdown locations

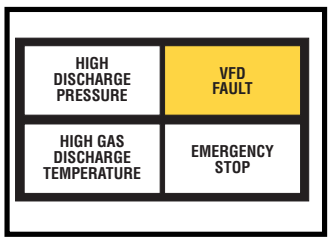
HS-111	Location
A	Software switch, someone has selected the STOP button on a DCS screen
B	SW corner AGO skid (skid 2)
C	NE corner of AGO skid (skid 2) near IA
D	SE corner of skid 1, near fuel preparation
E	SW corner of the digester gas skid
F	NE corner of EBOP
G	SW corner of EBOP

Resetting trips

To reset the trips you will need to know what first tripped the system, the first-out trip will have a yellow arrow next to it. Once the condition has been corrected, select the 1ST OUT RESET button. You will need to correct any other conditions that fail to clear as they arise.

The RESET MSG button resets the FAIL MESSAGE to NONE.

The reset trip trap button, resets the trip trap module.



4.3 Fuel Cell Alarms

The fuel cell has numerous alarms that register on the DCS computer. The first table lists all the alarms; the shaded boxes are the alarms which change setpoint and response depending on which phase of operation the fuel cell is in. The set point listed is the units the sensor register, ppm, psi, etc. The second table lists the shaded alarms, the set points and responses at the different phases of heat up, hot standby, power generation, or cool down. Some alarms also register on local control panels and must be reset locally. These alarms are in the following module.

Alarm output	Index Tag	Service	Setting and response	What to do
		Proprietary Information—Not Available for Publication.		

Alarm output	Index Tag	Service	Setting and response	What to do
		Proprietary Information—Not Available for Publication		

Alarm output	Index Tag	Service	Setting and response	What to do
		Proprietary Information—Not Available for Publication		

Alarm output	Index Tag	Service	Setting and response	What to do
		Proprietary Information—Not Available for Publication		

Alarm output	Index Tag	Service	Setting and response	What to do
		Proprietary Information— Not Available for Publication		

Alarm output	Index Tag	Service	Setting and response	What to do
		Proprietary Information—Not Available for Publication		

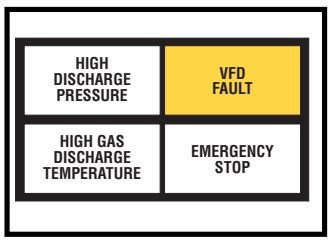
Alarm output	Index Tag	Service	Setting and response	What to do
		Proprietary Information— Not Available for Publication		

Alarm output	Index Tag	Service	Setting and response	What to do
		Proprietary Information—Not Available for Publication		

Alarm output	Index Tag	Service	Setting and response	What to do
		Proprietary Information—Not Available for Publication		

Alarms with multiple set points and responses

Alarm output	Index Tag	Service	Setting during HU 1	Setting during HU 2	Setting during HU 3	Setting during HU 4	Setting during NG Hot Stndby	Setting during NG PwrGen	Setting during DG Hot Stndby	Setting during DG PwrGen	Setting during CD 1	Setting during CD 2	Setting during CD 3
				Proprietary Information— Not Available for Publication									



4.4 Local System Alarms

All alarms go to the FuelCell Energy, Inc. operator's pager. The system can be controlled locally or remotely with an operator being dispatched from Fuel Cell Energy, Inc. The digester gas prepartion control panel, the burner management control panel, and startup skid local alarms are listed here.

Digester gas preparation panel alarms

Alarms	Cause	What to do
LOW LUBE OIL FLOW ALARM FSLL-801A	Lost vacuum in sightglass	Pump the piston next to the sightglass
LOW LUBE OIL LEVEL ALARM LAL-832	Low level	Check the level, fill the tank as needed
LOWLUBE OIL FLOW ALARM FSLL-801B	Lost vacuum in sightglass	Pump the piston next to the sightglass
LOW LUBE OIL LEVEL ALARM LSL-836	Low level	Check the level, fill the tank as needed
LOW OIL SEAL LEVEL ALARM LSSL-835	Low level	Check the valve lineup from the large oil tank
LOW GAS SEAL PRESSURE ALARM PSLL-832	Bottles are empty	Check the regulator setting on the bottle; replace as needed
SUCTION FILTER SERVICE REQUIRED PDSH-827	High differential pressure	Schedule service on filter
HIGH GAS DISCHARGE TEMPERATURE ALARM TSHH-833	Loss of cooling water	Check flow path to aftercooler is open; check the regulator setting
HIGH GAS DISCHARGE PRESSURE ALARM PSH-831	High discharge pressure	Check the VFD and /or PCV-819
LOW LIQUID LEVEL KO DISCHARGE LSLL-827	Low level	Verfiy drain valves are closed
KO DISCHARGE FILTER SERVICE REQUIRED PDSH-828	High differential pressure	Schedule service on fillter
LOW LIQUID LEVEL SUCTION KO LSLL-824,	Low level	Refill and verify the drain valves are shut
HIGH HIGH DISCHARGE TEMPERATURE TT-830 (TAHH-830)	High high digester gas temperature at the compressor discharge	Check the flow path through the compressor is open;check regulator setting
HIGH DISCHARGE TEMPERATURE TT-830	High digester gas temperature at the compressor discharge	Check the flow path through the compressor is open;check regulator setting
LOW LOW SUCTION KO LIQUID LEVEL LT-825	Low level	Verify the drain valves are closed

Digester gas preparation panel alarms

Alarms	Cause	What to do
HIGH HIGH SUCTION KO LIQUID LEVEL LT-825 (LAHH-825)	High level in the digester gas feed knock out drum. Trips the DG compressor.	Check the flow path is open. When the path is clear, reset and restart the DG compressor.
LOW LOW DISCHARGE KO LIQUID LEVEL LT-826	Low level	Check the drain valves are closed.
HIGH HIGH DISCHARGE KO LIQUID LEVEL LT-826 (LAHH-826)	High level in the digester gas dishcarge knock-out drum. Trips the DG compressor.	Check the flow path is open. When the path is clear, reset and restart the DG compressor.
VFD FAULT	Numerous reasons	Verify the DG compressor is still running, troubleshoot and reset the fault by truning the VFD off and the back on???, and restart the compressor if necessary.
LOW LOW FLOW ENCLOSURE FAN FSLL-805A	Low air flow and a fan is needed.	Check the fan for power, bad belts, or bearings. REVIEWER: DOES THE FAN HAVE A THERMAL RESET?
LOW LOW FLOW ENCLOSURE FAN FSLL-805B	Low air flow and a fan is needed.	Check the fan for power, bad belts, or bearings.

Burner management system panel alarms

Alarms	Cause	What to do
PAH 210B FUEL GAS HIGH PRESSURE	High gas pressure Trips AGO burner	Shuts off the burner. When the pressure has returned to normal relight the burner.
PAL 210B FUEL GAS LOW PRESSURE	Low gas pressure Trips AGO burner	Shuts off the burner. Trace the lines for closed valves. When the pressure has returned to normal relight the burner.
PAL 233B PRIMARY AIR LOW PRESSURE	Loss of air supply or blower has stopped.	Shuts off the burner. Check the air supply flow path, check the blower for power, bad belts or bearings. When the air supply is available relight the burner.
PAL 234B SECONDARY AIR LOW PRESSURE	Loss of air supply or blower has stopped.	Shuts off the burner. Check the air supply flow path, check the blower for power, bad belts or bearings. When the air supply is available relight the burner.
PAL 261 INSTRUMENT AIR LOW PRESSURE	Problem with the IA system	Shuts off the burner. Check the instrument air system, if compressors are running, check for a line leak.
EMERGENCY STOP	Emergency stop of the AGO burner either automatic due to an alarm or because someone has pushed the local E-STOP.	Shuts off the burner. Check for other alarms that would cause a burner trip. Check for anyone in the area.
BALL-233 FLAME FAILURE	Pilot and main burner are off.	Pilot system uses instrument air (IA) reduced to 10 psi and natural gas at 8 psi.

Burner management system panel alarms

Alarms	Cause	What to do
BALL-243 FLAME FAILURE	Main burner is off.	The main burner requires 900 scfm of air and 13 scfm of fuel flow to stay lit. Check the permisisives that would cause the flame to go out or not to light.
PAL-264 VFD PURGE LOW PRESSURE	NA	NOT USED.
TAH-246 THERMAL OXIDIZER HI HI TEMP	Too much fuel to the burner or not enough air. Shuts down fuel cell system.	Check the blower, check the fuel control valve (FC-230) controls (FV-230).
TAL-246 THERMAL OXIDIZER LOW TEMP	Too little fuel to the burner or not enough air. Shuts down fuel cell system.	Check the fuel flow path is open. Check the blower, check the fuel control valve.
HIGH LIMIT	There is a high limit alarm that will shutdown the heater if the heating coils get too hot.	There is a LIMIT RESET button to reset this alarm once the coils have cooled

Startup skid local alarms

Alarms	Cause	What to do
HIGH LIMIT	There is a high limit alarm that will shutdown the heater if the heating coils get too hot.	There is a LIMIT RESET button to reset this alarm once the coils have cooled

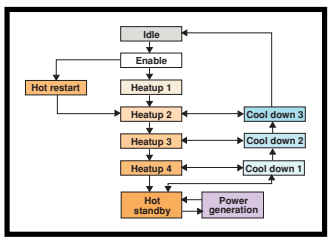
Water system local alarms

Alarms	Cause	What to do

Reference

SECTION 5
Fuel Cell System Control

5.1 Overview of the Fuel Cell System Controls 5-2
5.2 How the Fuel Cell Works 5-4
5.3 How the Support Systems Work 5-6
5.4 Overview of the Fuel Cell Startup Skid Controls 5-8
5.5 Overview of the Anode Fuel Preparation System Controls 5-10
5.6 Overview of the Oxidant Supply System Controls 5-12
5.7 Overview of the Fuel Cell Stack Module Controls 5-14
5.8 Overview of the Electrical Conditioning System Controls 5-16
5.9 Overview of the Instrument Air, Fire Alarm Panel, and Nitrogen Supply Controls 5-18
5.10 Overview of the Water Treatment System Controls 5-20
5.11 Overview of the Digester Gas Conditioning Controls 5-24
5.12 Enabling the Fuel Cell System for Startup 5-28
5.13 Heating Up the Fuel Cell Stack 5-30
5.14 Normal Fuel Cell Shutdown 5-32
5.15 Trip Recovery, Rapid Restart, and Hot Restart 5-34



5.1 Overview of the Fuel Cell System Controls

The fuel cell control system is quite complex. The system is controlled by an overall distributive control system (DCS) computer that interacts with several local programmable logics controllers (PLC) and the fire alarm panel. There are also several local control panels throughout the site. Together these elements control the fuel cell system. The system is either in idle, shutdown, power generation, or in one of its heatup or cooldown phases. Most sub systems of the fuel cell system have a section view. Detail screens provide control of most of the equipment.

Plant heatup and cooldown

The heatup and cooldown phases of the fuel cell system are managed through checklist screens. These show the items that must happen before the system can transition out of the current level or mode. Once all the items are checked off, an alarm will register to alert the operator that this mode is finished. The operator then choose to move to a new mode or hold at the current level.

Since the system is very complex and heatup and cooldown is a lengthy process, when an alarm registers, if appropriate, the control system will initiate a protective response (PPR). These protective responses, listed in order of increasing severity, include a heatup ramp hold, a reduced kW production step down, a hot standby step down, and a system shutdown.

Plant emergency shutdown and restart

In case of an emergency, to protect the system and the people the plant will shut down completely. This is called an emergency shut down (ESD). Any condition that could damage the fuel cell stack or other system equipment causes an ESD and nitrogen purge. The plant shuts down to one of three levels depending on the problem. These levels include a shutdown with auxiliary power available, shutdown with no auxiliary power available and the computer on UPS power, or shutdown with a computer failure. All shutdowns must be manually reset.

In the case of an emergency shutdown, once tripped, the fuel cell will start to cool on its own, because no more heat is being applied, this is called free cooling. If the fuel cell is cooling down and the condition that caused the shutdown is corrected, the system can be restarted.

Operator responsibilities on shutdown

Because the system is complex, when a shut down happens it is important that the operator verifies that the equipment status is correct for the type of shutdown that occurred, and that all relevant purges take place. It is also important that the operator fully document any shutdowns or system halts before troubleshooting and attempting to restart the system. This is done by finding the “first out” alarm, marked by a yellow arrow, and printing all the alarm screens connected with the shutdown, starting with the “first out” alarm screen. Then the equipment status is checked. Once the plant status is established, the operator must decide which method to use to restart the plant either a normal restart, rapid restart w/anode cover gas (ACG), or a rapid restart w/o ACG. The ultimate restart decision is made by team lead in consultation with FuelCell Energy management, based on what has happened, what the current plant status is, what the current fuel cell temperature is, and what energy is required.

Power outage

On loss of utility or grid power the fuel cell system will trip and shut down. The UPS and the instrument air receivers provide the power necessary to shut down the system safely. The fuel cell “free cools” or naturally cools down from the surrounding air until power is restored.

Proprietary Information
Not Available for Publication

Overview screen

Proprietary Information
Not Available for Publication

Faceplate with a detail screen

Proprietary Information
Not Available for Publication

Alarm screen with first out marked

Proprietary Information
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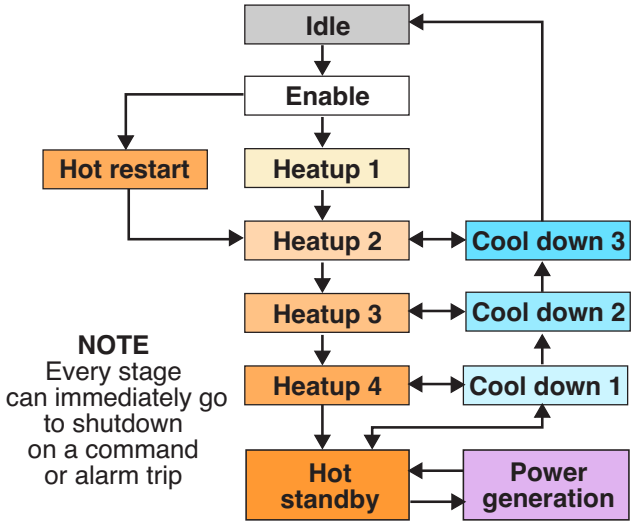
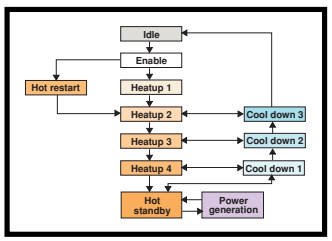
Heatup/cooldown screen with checklist



NOTE
Every stage can immediately go to shutdown on a command or alarm trip

The control system uses several modes to keep the fuel cell system active. Normally the system is either heating up, cooling down, in hot standby, or generating power



5.2 How the Fuel Cell Works

The fuel cell can be set to operate on several different operating modes or levels. These levels and the paths between them are shown in the illustration on page 5-3. The two active operating levels are hot standby and power generation. In either of these levels, the fuel cell is either generating power or ready to generate power (hot standby). It takes about 8 hours to move from hot standby to full power.The other operating levels happen when starting up or shutting down the fuel cell.

Control strategy

While many plant levels happen automatically in response to alarm set points (See *Section 4, Alarms*), most levels can also be chosen manually.

The heatup sequence proceeds through four stages, based on the temperature of the oxidant gas entering (cathode inlet) or leaving (cathode outlet) of the fuel cell stack. The heatup sequence can be halted at any stage due to alarms. The system will wait until the alarms clear before continuing the heatup sequence.

Cold start. The startup system skid does the initial heating of the fuel cell by recirculating a progressively warmer air stream through the fuel cell cathodes. This keeps the water vapor in the oxidant stream from condensing in the cold fuel cell stack.

Fuel cell stack temperature. Until the fuel cell stack is producing 750 kW of power the cathode temperature is controlled by TC-238, which controls the oxidizer burner's firing rate by providing a set points to the burner fuel (FC-208) to keep the oxidizer effluent at 1,110°Fand air flow (FC-230) controllers. Once the stack is producing 750 kW the main burner is turned off the cathode temperature is controlled by trimming the air flow, this is done with temperature controller TC-243. High-high temperature at TI-236C or TC-244 or at the catalyst inlet temperature will shutdown the fuel cell system.

Fuel cell stack air flow. The primary airflow controls direct compressed air to the oxidizer's thermal combustion section of the oxidizer burner. Primary air flow controller FC-230 monitors the primary airflow using flow transmitter FT-230, and controls the primary airflow using modulating valve FV-230. The oxidizer is controlled by the total air flow controller (FC-210). FC-210 maintains the air flow at 3,500 scfm until the fuel cell enters power generation. In power generation the air flow set point varies based on the current electrical demand trimmed by TC-243 to maintain a constant cathode inlet temperature.

Preconverter temperature control. During the initial warm up, the electric jacket heater preheats the preconverter to operating temperature. This is controlled locally.

Oxidant supply system. The oxidant supply system supplies a large flow of progressively warmer air through the fuel cell cathodes until the cathode inlet temperature is raised from 880°F (end or stage 2) to 1,100°F (end of stage 4). This heat up rate is 15°F per hour during heatup 2 and 4 and 12°F during heatup 3. Fuel flow to the burner is controlled by the cathode inlet temperature control (TC 238).

The oxidizer's natural gas burner is fired to provide the heat and the air blower runs at 3500 scfm to minimize the temperature differential across the fuel cell cathode.

Oxidizer catalyst section. The oxidizer's catalyst section is heated up to operating temperature using the oxidizer's tertiary air controls, the oxidizer catalyst must be above 1000°F for power generation. The ramp up is controlled by the AGO catalyst temperature controller (TC 244).

Oxidizer (AGO) burner). During plant heat up, cool down, or hot stand by, the oxidizer burner is lit and the fuel-to-air mixture is adjusted automatically to maintain the oxidizer discharge gas temperature.

Once in power generation mode, when operating at more than 75% power, the burner is not lit and the oxidizer discharge temperature is maintained by adjusting the air flow.

A normal oxidizer discharge set point is 1,110°F at Hot Standby to 1,005°F at full load power generation.

Burner gas feed automatic isolation valves. The valves close on a fuel cell shutdown. If the oxidizer is being fired when these valves close, a PLANT SHUTOWN alarm or a LOSS OF OXIDIZER PILOT LIGHT alarm registers. If the power load requires the burner the plant will NOT shut down, however operations are limited because the the plant must be tripped in order to relight the pilot.

(On a pilot light failure, a shutdown trip, the pilot must be relit before a shutdown or standby can happen.)

Natural gas heater. The natural gas heater (100-HE-101) starts and stops to maintain the incoming gas at 60°F. The heater cannot start unless there is gas flow at FC-117 (anode fuel gas) or at FC-208 (oxidizer burn fuel). The heater shuts down on high temperature. The heater control is at the local control panel. The heater pressure relief valve set at 20 psi to protect the system from over pressurization.

Humidifier. The water injection rate is controlled to maintain the steam-to-carbon ratio at or above what is needed: 2:1 for power generation; 8:1 for hot standby, plant heatup or cooldown.

The humidifier dampers are modulated to maintain the fuel deoxidizer outlet temperature at 775°F for natural gas and 800°F for digester gas.

Desulfurizers. The beds are normally operated in series as lead and guard. They are manually valved into the lead/guard position.

Sample ports are located in the middle of each bed. When a sample shows sulfur breakthrough, the lead/guard position should be switched. The contaminated bed should then be taken off line, purged with a portable bottle of nitrogen, emptied, and refilled. Once filled, the desulfurizer must be purged with nitrogen to remove the air. Then the outlet valve (FCV-112) is opened to allow gas to flow into the bed. The manual valves can then be configured to place it in the guard position.

Desulfurizer skid. The desulfurizers are in a heated enclosure. The temperature is maintained at 60°F. The enclosure has two ultraviolet/infrared flame detectors found in opposite corners of the ceiling. These detectors activate a local strobe and horn and alarm at the fire panel.

Two supply fans maintain a slight negative pressure within the cabinet If a fire is detected in the cabinet, the fuel cell is shut down, and the ventilation fans stop. One of two supply fans operates whenever the fuel cell system is started. The fans run in lead/follow. High temperature or low flow will start the follow fan. Failure of both fans shuts down the fuel cell system.

Anode fuel flow control. The flow control system controls the flow of anode fuel gas either from the cold gas desulfurizers or the digester gas conditioning system. It controls the steam-to-carbon ratio by modulating the amount of water that is added to the fuel, 2:1 for power generation; 8:1 for hot standby, plant heatup or cooldown.

Fuel superheater. The superheater acts passively. A normal operating outlet temperature is 900 to 1,000°F.

Oxidizer (fresh air) blower. In AUTO the blower starts as part of the system startup. The discharge valve opens when the blower starts. The blower will stop on a vibration alarm. The speed of the blower is modulated to maintain the set point on SC-224. The normal set point for the blower is 28 inches W.C. The blower discharge valve is normally open except for fuel cell shutdown.

Control options

Low-pressure sludge gas (LSG). The LSG supply has remote manual and automatic shutoff valves. The incoming LSG gas pressure relief valve is set at 15 psi. The remote shutoff is near the waste gas burners.

Preconverter. The preconverter performance can be judged by the temperature drop between the inlet and outlet gas temperature. A 175 to 250°F temperature drop indicates good performance (the temperature drop will be less when using digester gas). A smaller temperature drop shows the catalyst has been oxidized.

Preconverter afterfilter. The filter has been removed, only the housing remains.

Interlocks

- The nitrogen supply must be above low pressure to start the system.
- At least one desulfurizer cabinet fan must be operation to start up the system.
- The electric gas heater can only run if fuel is flowing (to the AGO burner).

Alarms

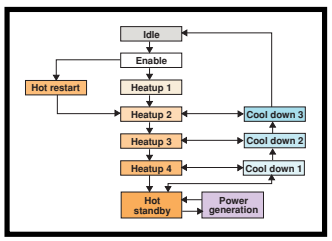
The fuel cell system include numerous alarms and alarm responses. See the individual system control description or *Section 4, Alarms* for more information.

Power outage

In a power outage the fuel cell system is shut down. The IA receivers supply enough air to operate all the valves necessary to safely shut down the system. The system will be restarted by the FCE operator.

Proprietary Information— Not Available for Publication.

Reference



5.3 How the Support Systems Work

The fuel cell system has several critical support systems, including the digester gas conditioning system which prepares the raw digester gas for the fuel cell, the water treatment system that cleans the impurities from the city water, the nitrogen purge system that purges explosive gas from the equipment and lines and protects the anode and cathode from damage, and the instrument air system which supplies the critical air actuated valves that can shut down the fuel cell system in case of a power outage.

Control strategy

Digester gas conditioning feed and discharge knockout drums. The knockout drums remove liquid from the gas. The liquid level inside the drum is controlled by the solenoid-operated drain valve (LV-825/LV-826). The valve opens on high level and closes on low level. A downstream solenoid drain valve will close on a low-low level.

Digester gas conditioning compressor. The compressor speed is varied to maintain a discharge pressure set point of 28 psi. Once the compressor is running at minimum speed, a bypass valve is opened to maintain the pressure set point. The compressor shuts down on high high or low-low pressure or high temperature. The compressor also shuts down if the low pressure sludge gas (LSG) header pressure is 4 inches W.C.

Digester gas cleaning. The digester gas travels though an high efficiency oil filter, a SulfaTreat vessel, and two digester gas polishers. These systems are monitored but there are no controls other than manual valves between the vessels. The gas polishers run in series with the fresher media in the first position.

Water treatment system. The water treatment system cleans impurities from city water. The system runs continuously it either makes up water for the storage tank anytime the tank is less than 90-percent full or recycles the water from the storage tank once it is full.

The makeup water cycle normally starts when the tank is 60-percent full and changes to recycle once the tank is 90-percent full. The supply pump starts just before the fuel enable signal. The pumps run in lead and follow, the follow pump starts if the lead pump fails. Both pumps will stop on a low low tank level.

Booster pumps supply high pressure city water to the water treatment system. They run in lead/follow, if both booster pumps fail a yellow beacon the shed lights, and the fuel cell system will shuts down.

Nitrogen (N2) bleed. The nitrogen bleed system provides a nitrogen cover to protect the cathode and anode on shutdown and anytime fuel gas has been used. One six pack provides for both flow paths. Flow rates are set passively by the orifice size used and the regulated pressure delivered. Automatic valves open XV-280 supplies 0.1 scfm to the anode, and valve XV-284 supplies 0.5 scfm to the cathode.

Nitrogen purge. Equipment and lines are purged of explosive gas with nitrogen anytime the temperature drops below a set point. One six pack provides both flow paths. Flow rates are set passively by the orifice size used and the regulated pressure delivered. An automatic valve (XV-191) opens and supplies 50 scfm to the fuel supply system downstream of flow valve FV-117; another valve (XV-282) opens and supplies 50 scfm to the anode side of the fuel cell. Valves XV-191 and XV-282 open on an emergency shutdown (ESD) whenever the fuel cell temperature drops below 650°F.

Valve XV-191 also supplies a nitrogen purge at 50 scfm if:

- the preconverter inlet temperature is less than 550°F,
- the preconverter internal temperature is less than 500°F or
- the fuel cell collector median is less than 650°F. supplies 0.5 scfm to the cathode.

Anode cover gas. Anode cover gas (nitrogen-based) is also provided to the anode on a rapid restart. The flow rate of anode cover gas is controlled by throttling needle valve HV-293. The

valve must be fully throttled to maintain the anode pressure needed (1 inch W.C. above the cathode pressure), while the AGO blower is running.

Instrument air. The instrument air system has two redundant systems that run in lead and follow. The compressors and dryer are powered up and down manually. The compressors start and stop automatically to maintain the receiver set point. The receiver provides enough air to shut-down the fuel cell system in case of a power loss.

Control options

Digester gas conditioning compressor. A local control panel has an ON/OFF and LOCAL/ REMOTE switches with buttons for manually adjusting the speed. The compressor is normally run in REMOTE.

SulfaTreat bed. The SulfaTreat bed should last about 40 weeks before the catalyst needs to be replaced. To replace the bed, the vessel must be depressurized and purged with nitrogen; the digester gas and nitrogen gas are released to the atmosphere in a safe area.

Gas polisher sorbant. Each gas polisher bed should last about 27 weeks before it needs to be replaced.

Instrument air compressors. The instrument air compressors are run in lead follow and AUTO. The compressors are turned to AUTO at the local control panels.

Instrument air dryers. The instrument air dryers are turned on manually at the local control panel.

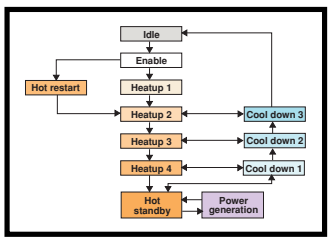
Alarms

The support systems have numerous alarms and alarm responses. See the individual system control description or *Section 4, Alarms* for more information.

Power outage

In a power outage the fuel cell system is shut down. The IA receivers supply enough air to operate all the valves necessary to safely shut down the system. The system will be restarted by the FCE operator.

Reference



5.4 Overview of the Fuel Cell Startup Skid Controls

The startup heater can produce 122,900 BTU/hour at 400°F and 5 psi. The 7.5 hp blower can produce 1,300 scfm at 18 inches W.C. The portable heating unit and blower are attached to cold start the fuel cell system. The equipment is isolated before the system reaches 300°F. Air above 300°F circulated through the blower will damage it.

Components

Startup blower. The portable startup blower (200-BL-101) suction is isolated from the cathode discharge bypass line by chain operated isolation valve (MV-2040) on an 8-inch pipe installed between the valve and a length of flex hose on the startup skid. Air is discharged into the startup heater. The blower has two silencers.

A manual MOTOR ON/OFF switch is located on the electronic heater/blower control panel.

Startup heater. Air from the blower enters the portable startup heater (200-HE-101). The heated air is blown into oxidant supply line (200-HF-101) to pre-warming the fuel cell stack. The heated air discharge through an 8-inch pipe. It is isolated by a chain-operated isolation valve (MV-2039) installed between the valve and a length of flex hose on the startup skid.

The heater is monitored locally for temperature and its pressure relief valve (PSV-260) is set at 5 psi and vents to the atmosphere.

CAUTION

When the system is shutdown it is important to isolate the blower and heater by closing the inlet and outlet valves. The air in the fuel cell will continue to heat up and air above 300°F circulated through the blower will damage it.

Control strategy

The startup heater and blower are manually valved in and started and stopped from the local control panel.

When the SETUP/OFF/ON switch is in ON, the local temperature controller TC-216 controls the ramp up rate to the heater to maintain a 15°F per hour heat up of the cathode. The controller automatically holds the temperature increase if the difference between the inlet and outlet temperature is 100 °F or more.

Control options

When using the system, the heater and the blower motor is normally turned to ON. The startup blower differential pressure and the heater pressure are monitored on local gauges.

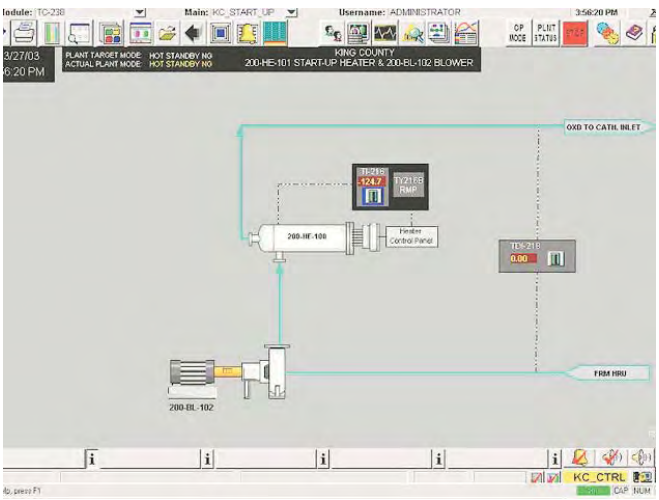
The local control panel has a SET UP/OFF/ ON switch, a POWER ON light, a HIGH LIMIT light, a LIMIT RESET button, a MOTOR OFF/ON switch, a MOTOR OFF light, a MOTOR ON light and the temperature controller.

Alarms

HIGH LIMIT. There is a high limit alarm that will shutdown the heater if the heating coils get too hot. There is a LIMIT RESET button to reset this alarm once the coils have cooled.

Power outage

The blower and heater are plugged into the welding receptacle on the corner of the fuel prep skid. In a power outage the startup skid will shutdown, the equipment should be turned off and restarted manually once power is restored.

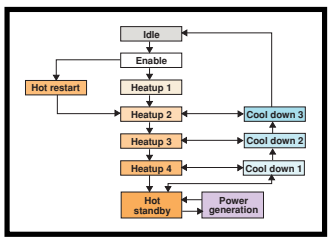


Startup system screen

Startup system local control panel

Startup system skid

Startup system local control panel



5.5 Overview of the Anode Fuel Preparation System Controls

Anode fuel can be scrubbed methane ("natural gas"), pipeline natural gas, or unscrubbed anaerobic digester gas. The anode fuel supply system either prepares natural gas for use as anode fuel and oxidizer-burner fuel, or prepares natural gas for oxidizer burner fuel and meters digester gas prepared by the digester gas condition system for anode fuel. The fuel gas preparation system for natural gas has supply isolation valves, an electric gas heater, a desulfurizer, a humidifier, a deoxidizer, a preconverter, a superheater, and an anode gas supply system.

NOTE: The fuel cell system is fueled either with anaerobic digester gas or with a scrubbed "pipeline quality" natural gas normally sold to Puget Sound Energy. "Natural gas" refers to scrubbed methane, "digester gas" refers to the unscrubbed anaerobic digester gas which must be pretreated before it is used in the fuel cell.

Gas supply and isolation

Metered, filtered, pressure-regulated gas enters the system through a manual isolation valve. The gas passes through a pressure reducing valve (PCV-101) that regulates it to 15 psi for the fuel gas preparation system. The cold gas desulfurizers do not work well with greater pressure.

The gas then passes through two automatic isolation valves (XV-103A/B). These valves close automatically on a fuel cell system shutdown.

Fuel gas preparation system

Inlet flow control. The flow control system controls the flow of anode fuel gas either from the cold gas desulfurizers or the digester gas conditioning system. It monitors the carbon content and molecular weight and controls the steam-to carbon ratio by modulating the amount of water that is added to the fuel.

The system is monitored for high and low flow, and a differential between the flow set point and gas actually measured at the flow meter. There are two systems, one for "natural gas" (NG) and one for anaerobic digester gas (ADG). On each system a flow controller (FC-800 or FC117) uses a flow meter (FE-800) and valve (FV-800[1]) to modulate the flow, and calculates the flow need for the current conditions, using a downstream analyzer (AI-100A&B).

1. Need a different valve number?

Gas heater. The electric natural gas heater (100-HE-101) maintains the incoming gas at 60°F for the cold gas desulfurizers. The temperature is controlled by a local controller, the DCS can only enable or disable this controller. The heater cannot start unless gas is flowing. It has a pressure relief set at 20 psi, and over temperature protection.

Desulfurizers. The desulfurizers absorb sulfur compounds. They are normally operated in series as lead and guard. Operating temperature and pressure affect the absorption rate. Each bed will last about 27 weeks. The desulfurizer after filter prevents small particles from getting into the fuel stream. The differential pressure is monitored to indicate when the filters need changing.

Analyzer. An analyzer (AE-100) monitors the gas content. In natural gas mode, when the methane content is below 80 percent and oxygen content is above 0.2 percent, the system switches to peak shave gas (PSG) mode. Low methane, high oxygen level, and high and low inlet pressures cause alarms. The analyzer also determines the carbon content, whether using natural gas or digester gas.

Humidifier. The gas is then humidified (using purified water from the water treatment system) and preheated in the fuel humidifier (HX1), a part of the heat recovery unit. The water injection rate controller (FC-131) maintains the steam-to-carbon ratio needed: 2:1 for power generation, 8:1 for hot standby, heatup, or cooldown. The water supply valve (FV-131) closes on a fuel cell system trip or whenever "gas enable" conditions are not met.

The humidifier damper louvers are controlled to keep the fuel-steam mixture temperature at the fuel deoxidizer outlet at 775°F. This temperature

provides peak performance for the deoxidizer and preconverter catalyst. Low humidifier exit temperature is alarmed and a low-low temperature puts the system on hold, a plant protective response (PPR).

Deoxidizer. The steam-fuel gas mixture is then passed through a fuel deoxidizer (100-RR-102) to remove the oxygen. This protects the preconverter and the fuel cell catalysts from oxidation. Chemically removing the oxygen also heats the gas. (Oxygen is only a problem if peak shave gas (PSG) mode is used.

Preconverter. The preconverter (100-RR-1030) is part of the heat recovery system. Carbon and hydrocarbons are reformed to H_2, CO and CO_2 in the reforming reaction, and a shift reaction converts the CO and water into CO_2 and H_2. This frees the hydrogen and avoids carbon (C_2^+) propane (C_3H_8) and methane (CH_4) from buildup in the fuel cell stacks.

The system is monitored for inlet/outlet temperature differential. Normally the number is negative. At 0°F the low alarm registers. At a positive value, a high-high alarm registers and the fuel cell shuts down. The preconverter is also monitored for an inlet temperature differential (the second temperature that is used for the differential is from a point 9 inches down in the bed)—normally this number is negative. At either a low negative number or a positive number, a loss of preconverter catalyst activity and a high-high differential alarm registers.

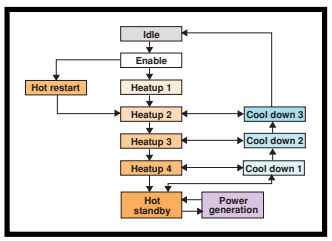
Fuel superheater. The fuel superheater (HX2), a part of the heat recovery system. Fuel is passively heated in the heat exchanger by heat from flue gas and is sent to the fuel cell stack module (300-VE-101).

Anode fuel gas supply

Heat traced pipe. The fuel leaving the fuel superheater enters the anode fuel inlet of the fuel cell stack module through a high temperature heat traced pipe so that the fuel remains above 960°F.

Inlet block valve pair. The inlet is controlled by a an isolation or block valve and a vent valve. The inlet valve (XV-247A) is used to isolate the fuel cell stack from the fuel gas treatment system whenever the fuel cell system is shutdown. For safety, a vent line is locate upstream of the inlet valve. The vent valve (XV-247B) is opened when the inlet valve closed. This allows the vent to release fuel gas and nitrogen purge gas to the atmosphere. The temperature of the vent line is monitored about 1 foot from the vent valve to be sure that the vent valve is fully closed during normal operation, because the fuel gas is toxic and flammable. A high-high vent line temperature alarm shuts down the fuel cell system. Closing the inlet valve (XV-247A) also shuts down the fuel cell system.

Outlet block valve pair. The outlet is controlled by a similar set of valves with similar functions. The vent is upstream of the outlet valve (XV-262), and the vent valve is XV-260.



5.6 Overview of the Oxidant Supply System Controls

The oxidant supply system provides air for cathode oxidant makeup and generates cathode oxidant gas for fuel cell power generation. It collects anode exhaust gas from the fuel cell stack module, mixes it with the pressurized air, catalytically oxidizes the stream to remove excess hydrogen and methane, and delivers the oxidant gas to the fuel cell stack module. The system consists of a blower, a anode gas oxidizer (AGO), and the heat recovery unit.

Components

Air blower. The AGO blower or fresh air blower (200-BL-101) is a rotary air blower with a variable speed drive that provides up to 5,000 scfm air to the oxidizer and provides cooling for the oxidizer sightglasses and flame detector. The blower suction has an inlet air filter and a silencer. The inlet filter pressure drop is monitored. The blower discharge has an automatic isolation (block) valve (XV-241). This valve is closed during fuel cell shutdown to prevent air from leaking into the fuel cell stack. The discharge valve position and the discharge air temperature are monitored. If the discharge valve (XV-241) is closed, the fuel cell will shut down.

Anode gas oxidizer (AGO). The thermal/catalytic oxidizer (200-HF-101) has a natural gas burner, a thermal reactor, a catalytic reactor, and fuel piping. The burner and its pilot must burn "natural gas" (scrubbed pipeline quality methane from the cold gas desulfurizers). Digester gas cannot be used because the heating value is too low.

Control strategy

Air flow control. The oxidizer splits the air from the AGO blower into three streams. The primary air flow supplies a minimum air flow for burner light-off and otherwise maintains the fuel-to-air ratio. The secondary stream provides the remainder of the air flow required to maintain the fuel cell temperature and provides enough flow to provide heat to the humidifier and superheater. The third stream of air is used to cool the oxidizer discharge so that if needed the catalytic section can be operated at a higher temperature than the oxidizer discharge.

During plant heat up, cool down, or hot standby, the oxidizer burner is lit and the fuel-to-air mixture is adjusted automatically to maintain the oxidizer discharge gas temperature. This flow to the thermal reactor (primary flow) is monitored by a flow controller (FC-230) which controls a flow control valve (FV-230). This valve has a stop so that even when closed, it provides 900 scfm of air which is the minimum air required for the safe operation of the burner.

During power generation, when generation at least 75-percent power, the burn is not lit and the oxidizer discharge temperature is maintained by adjusting the air flow. The total air flow is monitored at a flow controller (FC-210) and secondary air flow is controlled by a flow valve (FV-210) to maintain the total flow set point.

Tertiary air flow is controlled by TC-425 to maintain a catalyst discharge temperature. See "Catalyst section temperature control." on page 5-15.

Fuel flow control. Fuel gas inlet flow is monitored and low pressure activates an alarm if the burner is being fired. The main burner supply valves (FV-208A/B) both close if the oxidizer is shut down. Fuel is fed to maintain a 1,010°F oxidizer gas discharge temperature or the temperature required by the current heatup or cooldown ramp.

Fuel flow isolation. There is a pair of isolation or block valves (XV-212 and XV-214) on the fuel line. A similar pair (XV-203 and XV-205) is on the pilot supply line.

Burner control. The fuel flow adjustment always lags behind the air flow adjustments. The flow controller uses two flow control valves to adjust the fuel flow (FV-208A/B) for a total 28:1 turn down adjustment.

The pilot is lit when the burner is called to operate. The pilot light-up sequence requires a purge of 900 scfm of primary air flow for two minutes before the pilot and instrument air block

valves will open. Three valves on the pilot fuel supply must be opened before the electric ignitor fires. The pilot fuel supply is shut off about 15 seconds after the main burner is lit, and the pilot is relit when the burner is shut down.

The main burner requires 900 scfm of air and 13 scfm of fuel flow to stay lit. High pressure at the main burner inlet causes an alarm.

The main burner is shut down when no longer needed, but the pilot relight must be confirmed before it can be shutdown. The burner is then set to "on call" with the burner fuel and air flow at minimum and the controller in manual. Once the main burner lights the controller is put in auto, and the burner fuel flow is then controlled to maintain the oxidizer gas discharge temperature set point on temperature controller TC-238.

The pilot system uses instrument air (IA) reduced to 10 psi and natural gas at 8 psi. The IA supply valve opens when the pilot is operating. Low IA pressure causes an alarm.

Both the burner and the pilot have flame detectors to confirm ignition. If the burner is called for and fails to light, the system must be shut down and restarted even though the catalytic system is still working.

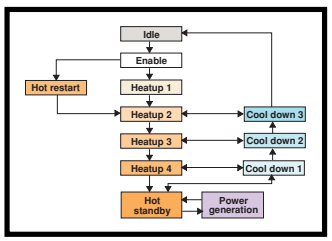
Catalyst section temperature control. To make sure the temperature is correct for the catalyst chemical reaction to occur (1,000 °F), during heatup a small stream of cold air (tertiary) is used to control the temperature of the catalyst section. The air is directed to the oxidizer discharge to maintain the catalyst discharge temperature set point. During power generation or hot standby the catalyst inlet temperature is kept above 1,000°F and below 1,250°F. During heatup and cool down, the catalyst discharge temperature is maintained above 1,000°F to oxidize the methane in the anode exhaust gas before it is vented to the atmosphere. A high high catalyst inlet temperature or a high high outlet temperature shuts down the oxidizer.

Anode gas oxidizer (AGO) response to power generation. As the fuel cell stack starts to load and generate power, it starts to use the all gas delivered to it, causing the gas that was going to the AGO burner to decrease and the AGO to cooldown. Temperature controller TC-238 will increase the fuel flow to the burner during this period to maintain the discharge setpoint.

Cathode exhaust system

Cathode exhaust gas is routed to the heat recovery unit, where an exhaust gas polisher removes any combustible gases. The gas is then used as the heat source for the fuel superheater (HX2) and fuel humidifier (HX1). The gas temperature is monitored at the heat recovery unit inlet. A high-high temperature shuts down the system. The exhaust is monitored for combustible gas. A 25 percent LEL causes an alarm to register and a 60 percent LEL shuts down the fuel cell system. The cathode exhaust gas, at 600° to 700°F, is vented to the atmosphere, or used in the waste heat recovery system.

NOTE: Some of the cathode exhaust is used by the South Plant heat recovery system, described in South Treatment Plant Operations Manuals, Volume 1, Plant Overview.



5.7 Overview of the Fuel Cell Stack Module Controls

Each fuel cell stack module contains four fuel cell stacks. Inside the fuel cell stacks, anode fuel gas is reformed and electrochemically reacted with the cathode oxidant gas to generate DC power. The anode exhaust gas is discharged to the oxidant supply system and cathode exhaust gas is discharged to the heat recovery system.

Fuel cell stack controls

The fuel cell stack receives oxidant from the oxidant supply system (200-HF-101) and anode fuel gas from the anode fuel supply system (100-HR-101/HX2) or from the conditioned digester gas system. It also receives nitrogen purge and bleed gas from the nitrogen supply system. The system discharges anode and cathode exhaust gas and generates DC electricity.

Control strategy

Fuel cell stack LEL. This vessel has two combustible gas detectors (AE-342A/B). A lower explosive limit (LEL) of 25 percent registers as an alarm at the fire panel. An LEL of 60 percent shuts down the fuel cell and activates a horn and blue rotating beacon.

Fuel gas flow. Desulfurized fuel gas (either "natural gas" or digester gas) is combined with treated water to produce a fuel gas/steam mixture suitable for feeding as anode fuel gas to the fuel cell stack module. The steam is needed by the preconverter and deoxidizer as a reactant for the reforming and shift reactions that generate hydrogen from the natural gas fuel.

The steam-to-carbon ratio is a critical element of the fuel cell control. For power generation a ratio of 2:1 is used. For hot standby, fuel cell heatup, and cooldown, 8:1 is used. When little fuel is needed, this higher steam ratio provides more volume for better fuel distribution.

Stack temperature. The oxidant supply system provides the temperature control of the fuel cell stack. During heatup and cooldown, hot standby and power generation below 75-percent, the anode gas oxidizer (AGO) burner fuel flow is varied to control the temperature. During power generation above 75-percent, the stack temperature is controlled by the oxidant air flow.

NOTE: The temperature of the anode fuel gas entering the fuel cell stack is not controlled. It is dependent on the temperature and flow of the cathode exhaust gas to the fuel superheater. It must be maintained above 960°F once hot standby is reached.

The fuel cell stack inlet temperature (TI-320) of the cathode air is monitored during cooldown. A temperature below 650°F starts a nitrogen purge of the fuel cell stack.

Stack pressure. The pressure within the fuel cell stack is not controlled. The pressure is the result of the accumulated system pressure drops throughout the system. The pressure differential of the anode inlet/outlet and the cathode inlet are monitored to detect leaks inside the cells, between the anode and cathodes. The DCS receives the anode fuel gas supply header pressure (PI-251), exhaust gas header pressure (PI-252), cathode exhaust gas header pressure (PI-253), and fuel cell cathode side vessel pressure (PI-309). Two differential pressure transmitters on stack A and C measure the differential pressure from the fuel turn to the cathode vessel.

The anode outlet-to-cathode outlet differential pressure is calculated and a high differential pressure activates a DCS alarm. High-high differential pressure alarm initiates a kW ramp down.

The pressure drop across that stack's anodes should be less than 5 inches W.C. The reforming unit (RU) and RU inlet header pressure can not exceed 1 psi or 28 inches W.C.

Monitoring fuel distribution

Monitoring the cell voltages, the pressure, temperature and composition at the fuel turn manifold gives a good indication of the fuel distribution between the four stacks.

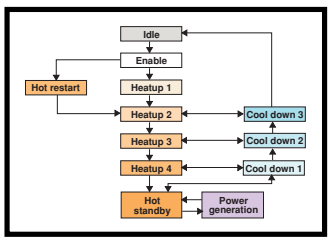
Voltage. The absolute voltages of individual fuel cells and voltages generated across groups of fuel cells within the individual stacks are monitored by the DCS. The average voltage is calculated and displayed on the operator interface unit.

Cell group voltages are used to determine the response and health of the stack. During ramps and while in steady state the cell group voltage deviation is used to monitor the stack and various alarms and plant protective responses (PPR) are automatically triggered based on the reading of these deviations. For more information see *Section 6, Operators Notes—Monitoring Cell Group Voltage Deviation, page 6-12*

Fuel flow rate. It is critical that the fuel cell stacks not be starved of fuel or limited by the concentrations and flow of reactants (H_2, 0_2, CO_2) within the stacks. Starvation reduces the life and performance of the stacks. It is the hydrogen content of the fuel reaction within the fuel cell anodes, that generates the electricity.

The fuel utilization set point is a preset value, the theoretical amount of hydrogen available, when using natural gas; it comes from the gas analyzer (AT-100) when using digester gas. The fuel flow set point varies based on the electrical current drawn from the fuel cell module, whether the fuel cell is running on scrubbed digester gas or conditioned digester gas (natural gas or digester gas mode).

The anode fuel components, methane and steam, are controlled and monitored carefully by the system and numerous alarms and trips protect the plant from incorrect flows.



5.8 Overview of the Electrical Conditioning System Controls

The electrical conditioning system is a part of the electrical balance of plant. It converts the DC electric power generated by the fuel cell stack module into AC electric power. It has electrical system protective devices and the distribution and control devices for auxiliary loads. The electrical outputs of the four fuel cell stacks are connected in parallel to a common DC bus. The positive (cathode) terminal is resistance grounded. The stacks are electrically isolated by blocking diodes. To start power production, the power conditioning system and grid must be "ready" to accept power. The operator picks either load reduced or load rated power level, and the DCS starts a power ramp up. Once about 750 kW is produced, the anode exhaust stream should maintain the fuel cell stack temperature without the oxidizer burner. A fully ramped up system should produce about 1 MW of net power.

Electrical conditioning system enclosure. The electrical balance of plant (EBOP) is an outdoor, non walk-in enclosure containing the power conditioning system, DC power fuses, DC grounding circuit, DC isolation diodes, AC utility interconnection circuit breaker and protective relaying, the DCS computer equipment, a UPS, and the low voltage distribution equipment.

DC power. The amount of DC current drawn from the fuel cell stacks is controlled based on the current power level set point (NET AC POWER TARGET) and the ramp rate that has been set on the DCS. The ramp rate is 2kW per minute. There is also a calculated maximum amount of current that can be produced; this is based on the fuel flow.

The DEMANDED IDC (DC current), the UF (fuel utilization), and DEMANDED S/C RATIO (water flow for steam-to-carbon ratio) is calculated by the DCS.

Inverters. The four inverters operate in parallel. The two-stage inverters have step-up chopper front ends to boost the variable DC voltage from the fuel cell to a fixed DC voltage. The fixed DC then enters the voltage source inverter which converts the DC voltage to 400V AC. A single-stage inverter directly converts the variable DC voltage from the fuel cell to 150V AC.

Each inverter's output is then connected to the 480VAC power grid through a step-up isolation transformer.

Power conditioning system. The power conditioning system inverters use pulse width modulation (PWM) of the power semiconductors to provide AC electric power at 480V, 3-phase, and 60 Hz that meets the requirements of IEEE 519.

The system is only capable of operating in grid-connected mode at South Plant. Island mode is not available.

Grid-connected. The system is grid-connected whenever it is connected to the electrical grid. The net AC power output setpoint is operator-selected on the DCS, and the power condition system is operated to maintain this set point.

Monitoring

For monitoring information *Section 6, Operators Notes—Monitoring Cell Group Voltage Deviation, page 6-12*

The DCS receives data from the electrical conditioning system either from modbus or profibus links. The operator interface unit displays the current DC set point, DC current limit, VAR set point, stack string current, DC module voltage, total AC kW output, AC output voltage, AC output current, total kVA output, and output power factor. The following faults are tracked: open contactors on the ground fault.

Total module current. The total module current is the sum of the four stack's DC current output. The four stack currents are also checked for important performance differences that could be caused by uneven stack degradation, fuel leaks, or uneven fuel gas or oxidant gas distribution. A stack current high deviation alarm registers if the difference exceeds 10 percent. Low voltage activates an alarm, and low-low voltage initiates a PPR.

Control options

The system has a START/STOP switch that starts and stops AC power generation. A mode switch allows the operator to choose GRID-CONNECTED or ISLANDED, and shows whether the AC circuit breaker is open or closed.

A COMMON TROUBLE alarm also registers to indicate the following: a DC power conductor blown fuse, a DC ground fault blown fuse, a PCS (power conditioning system) tripped, a UPS common trouble, and a UPS on battery alarm.

Calculated set points

The power level is calculated from the net AC power set point, offset to estimate the gross power needed to achieve the power level. The actual gross AC power generated is then compared with the demand. This DEMANDED GROSS AC POWER is changed, limited by the fuel cell ramp rate.

DC current demand and total air flow, and the target values for steam-to-carbon ratio and the fuel use are calculated by the computer using a lookup table. The total carbon content of the fuel gas is also calculated.

Ramp limits. Certain factors determine how adjustments must be made, these are factors programmed into the DCS computer.

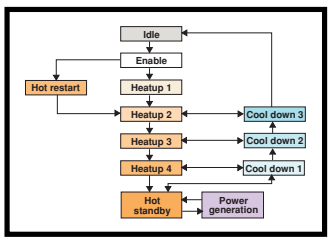
- Fuel gas flow must “lead” steam flow during decreasing load ramps, and “lag” steam flow during increasing ramps.
- Fuel gas flow must “lead” increases in power demand and “lag” decreases in power demand.

Power outage

On loss of utility or grid power the fuel cell system will trip and shut down. The UPS and the instrument air receivers provide the power to shut down the system safely. The fuel cell “free cools” or naturally cools down until power is restored.

For more information on powering up the electrical system and restarting after a power outage see *Section 6, Starting the electrical system, page 6-88* and *Section 6, Restoring power following a power failure, page 6-91*.

UPS. For more information on the UPS see page 6-91.



5.9 Overview of the Instrument Air, Fire Alarm Panel, and Nitrogen Supply Controls

Purified city water supply, instrument (IA) air supply, and nitrogen supply system must be available for the fuel cell system to startup. A fire alarm panel monitors safety concerns and uses the DCS to shut down the fuel cell system when needed.

Instrument air system

The IA system uses rotary oil-free compressors and produces dry, compressed air. It is designed to compress 25 scfm to 100 psi with a dewpoint of -40°F. The air is used to operate pneumatic control valves, to purge the electrical conditioning equipment panels, and as pilot light combustion air.

The system has two air compressors, two air receivers, two prefilters, two after filters, and two air dryers. Each compressor has a trouble and a shutdown alarm. The instrument air lines between the compressor and the dryers are heat traced and insulated to provide protection from freezing in winter.

Control strategy. The IA system is powered up from the local control panels and operates automatically to maintain a set point. The IA system pressure is monitored, and low and low-low alarms register at the DCS and a low-low alarm shuts down the fuel cell system. The receivers store enough reserve air to operate the air actuated valves used to shutdown the fuel cell system in case of a utility power outage.

Fire alarm system

The fire alarm panel is located on the north end of skid 1. The fire alarm panel uses the DCS to activate alarms and shutdown the fuel cell system. In case of a power outage the fire alarm panel has a battery backup.

- A fire alarm registers at the fire panel, shuts down the fuel cell, and activates a horn and red flashing beacon.
- A toxic gas (hydrogen sulfide) level of 5 ppmv registers as an alarm at the fire panel. A hydrogen sulfide level of 15 ppmv shuts down the fuel cell and activates a horn and yellow flashing beacon.
- A lower explosive limit (LEL) of 25 percent registers as an alarm at the fire panel. A level of 60 percent shuts down the fuel cell and activates a horn and white flashing beacon.

The digester gas compressor enclosure has two hydrogen sulfide detectors (AE-801/2), two ultraviolet and infrared flame detectors (AE-820 and AE-830), and a combustible gas detector (AE-805) located 1 foot below the ceiling.

LEL detectors are also located in the deoxidizer/preconverter area, near the oxidizer, and near the SulfaTreat vessel. There are also two hydrogen sulfide (H2S) detectors located near the high efficiency oil filter, and near the SulfaTreat vessel inlet.

Nitrogen gas supply system

The nitrogen gas supply system provides low-pressure nitrogen gas for purging during shutdown. Purging prevents vacuum and condensation caused by cooling, and prevents nickel carbonyl formation. The system has two six-packs of high pressure cylinders inside the cold gas desulfurizer enclosure. The supply pressure relief is set at 3,000 psi. Local pressure gauges are available. The fuel cell system will not heatup unless the nitrogen gas supply system is operating. South Treatment Plant supplies the nitrogen gas six-packs for the purging system.

Purge nitrogen. The pressure is stepped down to 40 psi at the distribution header, with a local pressure relief set at 50 psi. The header manifold supplies about 50 scfm to the inlet of the fuel humidifier and to the anode fuel gas inlet. The system purges the fuel deoxidizer, the preconverter, the heat recovery unit, and the fuel cell stack module. The nitrogen supply valve at the humidifier (XV-191) and at the fuel cell stack (XV-282) will not open unless the vent lines are open. The system is alarmed for high and low pressure.

The fast purge system can produce 100 scfm total: 50 scfm to the fuel treatment system through

valve XV 191, and 50 scfm to the anode of the fuel cell though valve XV 282. Both are vented to atmosphere.

Nitrogen bleed. The pressure is stepped down to 40 psi at the distribution header, with a local pressure relief is set at 50 psi. The header manifold supplies about 0.6 scfm total: 0.5 scfm to the cathode through valve XV-284, and 0.1 scfm to the anode through valve XV-280. Both are vented to the atmosphere. The system is alarmed for high and low pressure. This is sometimes called the slow bleed system.

Anode cover gas. The flow rate of anode cover gas is controlled by throttling needle valve HV 293. Anode cover gas is needed during the rapid restart process or trip recovery, whenever fuel gas had been flowing before the trip. The gas is nitrogen with 3±0.5 percent hydrogen; it is mixed with 0.1 scfm of pure nitrogen from the anode slow purge system.

The logic closes the anode inlet and outlet block and vents (XV-247A, XV-247B, XV-260 and XV-262) and opens anode N2 bleed valve (XV-280). The DCS then opens cover gas isolation solenoid valve (XV-290) and introduces the cover gas into the anode.

The logic prevents the AGO blower from starting until a 1 inch W.C. differential pressure (DPI-257) exists between the cathode in (PT-309) and the anode out (PT-252), for 60 seconds.

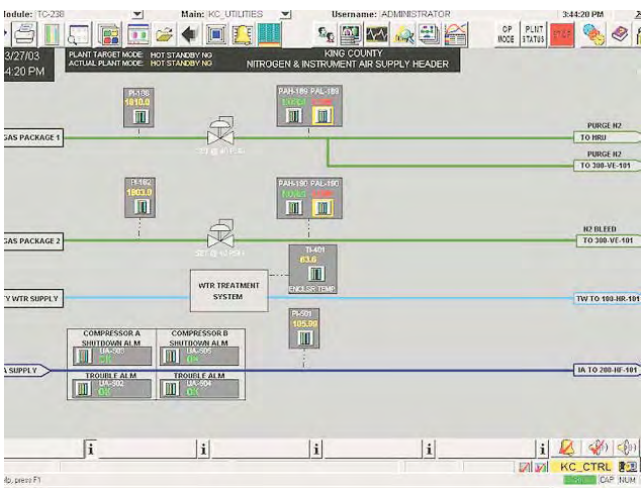
Once the anode and cathode differential pressure have been confirmed and the 60-second timer times out, the AGO blower is started.

The AGO system heats up the fuel cell to the fuel enable set point. Then the fuel block valves (XV-247A and XV-262) are opened, and fuel is enabled using FV-117. After a 10-second delay, the cover gas isolation valve (XV-290) closes.

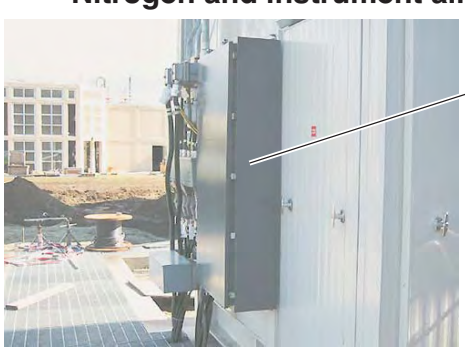
The DCS monitors the cover gas supply pressure (PT-290). A low pressure set point indicates that a cylinder needs replacing. DCS interlock prevents the plant from starting a Rapid Restart with anode cover gas if the cover gas pressure is below the low set point.

Pressure transmitter PT-290 monitors the supply pressure in the cylinders. The cover gas is filtered in FL-290 and then passed through regulator PCV 290, which is set at 40 psig. Pressure gauges PI-291 and PI-292 monitor the upstream and downstream pressure of the regulator. Relief valve PSV-290, set at 50 psig, protects the anode cover gas distribution header. Anode cover gas is supplied by opening valve XV-290 (on to open/off to close). Gas flow rate is controlled by needle valve HV-293. Check valve CHV-290 prevents the entry of any fuel gas into the anode cover gas system. The cover gas is mixed with 0.1 scfm of pure nitrogen from the purging system. The anode cover gas line is tied into the 3-inch mixing tee at the anode inlet.

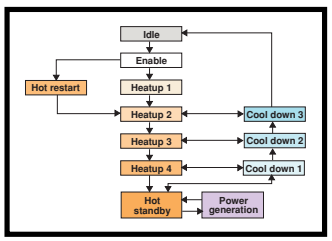
Maintenance nitrogen. Nitrogen gas is also needed for maintenance, but this is supplied by portable tanks. Nitrogen purging is required before and after fuel gas pipes are opened or before changing out the cold gas desulfurizers, the SulfaTreat vessel, and the digester gas polishers.



Nitrogen and instrument air supply



Fire alarm panel



5.10 Overview of the Water Treatment System Controls

The water treatment system (400-WT-101) purifies chlorinated municipal water for makeup water for the fuel humidifier located in the heat recovery system. It also provides a 12-hour reserve supply of water when the system is out of service. The system has its own PLC. The PLC controls filter backwashing, water softener regeneration, storage tank level control, reverse osmosis control, deionization control, and water pump control. Water quality is measured at several points in the system, and displayed locally and on the DCS.

The system has a multimedia filter, two water softeners, a brine tank, a carbon filter, an anti-scalant tank and injection system, a reverse osmosis unit with prefilters and a booster pump, a deionization unit, mixed bed polishing units, a purified water storage tank, a cartridge filter, and water pumps.

Enclosure

The system is housed in a heated enclosure that is kept at 40°F by a unit heater with a local thermostat. A ventilation fan is used for cooling; it comes on at 80°F from a local thermostat. The enclosure is monitored, and high, high-high, low and low-low temperature alarms register at the DCS.

Pretreatment

Activated carbon filter and Jelcleer filter. When the filter is in backwash, the downstream equipment is locked out. When the PLC starts the backwash, the filter is stepped through a backwash sequence, and then put back in service.

Water softeners. The water softeners operate in duty/standby. One softener is always online. When the output flow totalizer indicates that a softener needs regeneration, the unit controller switches leads, puts the softener in regeneration. During regeneration a highly concentrated brine is pulled into the softener, and diluted with water. The softener is then backflushed at 5 gpm and put in standby.

Anti-scalant injection. The anti-scalant injection metering pump runs whenever the reverse osmosis unit is running. The pump has a manual setting for stroke and frequency so the operator can choose the dosing rate. If the anti-scalant tank level is low, the reverse osmosis unit is locked out and the metering pump stops. A mixer is mounted on the anti-scalant tank.

Reverse osmosis

The reverse osmosis (RO) system has an OFF LINE/AUTO/HAND switch. It has three conductivity monitors and three flow monitors.

Control strategy. In AUTO, the unit will run if the activated carbon and/or Jelcleer filters are not being backwashed, the anti-scalant tank does not have a low level alarm, and the high pressure pump (PU-2) is running.

When the unit starts the feed water inlet valve (XV-415) opens, and the high pressure pump (PU-2) and anti-scalant injection pump start. When the unit stops the high pressure pump stops and the feed water inlet valve closes. The reverse osmosis flush switch (SS2) is in AUTO the unit will start and run for 5 minutes of every 2 consecutive hours of down time.

In HAND the system runs in override.

Reverse osmosis pre-filters. The pre-filters use three 5.0 micron cartridge filters. One is located on the inlet piping as a pressure transmitter PT-410, and the other is on the outlet piping as pressure transmitter PT-411. If the reverse osmosis unit pressure differential is more than 1 psid for 5 seconds, a high alarm registers.

Deionization

The system uses a continuous electro deionization unit, three polishing units (mixed bed DI exchange units), an after filter (FL-6), a product water storage tank (TK-3), and water transfer pumps (PU3 and 4). A recycle line downstream of

the polishing unit can recycle water back to the inlet of the reverse osmosis unit.

Control strategy. On a LOW CDI PRODUCT QUALITY alarm, on high conductivity at the output of the polishing unit, or when there is no call for water from the fuel cell and the storage tank is full, the recirculation valve on the inlet of the reverse osmosis unit (XV-442) opens and DI storage tank inlet valve (XV-443) closes and flow is recycled. If conductivity continues to be too high, the water treatment system shuts down.

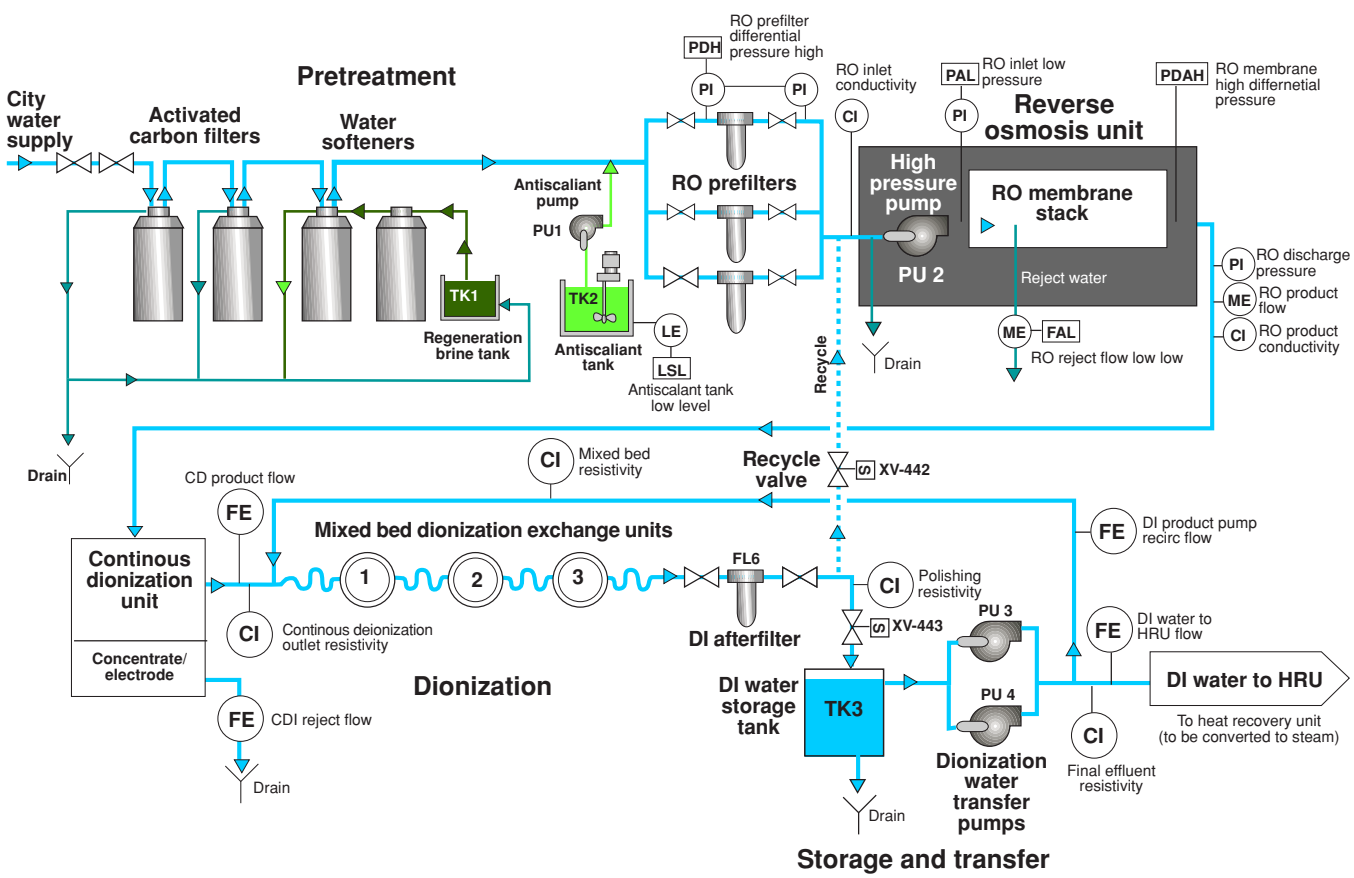
Continuous electro deionization reject flow. The incoming flow is split between the two inlets on the unit and about 0.4 gpm of electrode flow that contains impurities (reject flow) is sent to a drain. The deionization unit is turned on based on the amount of reject flow, it turns off as reject flow slows.

Polishing units. Three gpm of water from the deionization unit flows to the mixed-bed service deionization units that are run in series.

Manual isolation valves allow removal and replacement of the units. When increasing conductivity at the outlet of the second unit indicates that the unit is exhausted, the system shuts down. The primary and secondary units are removed. The third unit, that was uses as a polishing unit, is then moved into the primary position and two fresh replacement units are put in the other two positions. The system is then returned to service. The conductivity monitor (CIT-403) is on the main control panel.

Storage and transfer

Deionized water storage tank. This tank is also called the product water tank. The tank has inlets for normal flow (from the polisher) and transfer recycle flow. Level sensors in the tank are used to control the flow of water in and out of the storage tank. Normally, the deionized water flows at 3 gpm from the polishing units through the automatic deionization storage tank inlet valve and into the tank.



Control strategy. If the water in the tank is at high level (90 percent full) and the fuel cell requests water; the PLC starts the lead deionization water transfer pump and recycles water through the reverse osmosis and deionization units. This allows the reverse osmosis unit and deionization units to remain in service until the level in the tank drops. Once the storage tank level falls below the low level set point (60 percent), the tank starts to fill. A low-low tank level (20%) shuts down the downstream deionization water transfer pump until the level in the tank rises. If a low CDI resistivity is measured flow is also diverted from the deionization tank. The tank has a manual drain.

Deionized water transfer pumps (PU-3/4). The transfer pumps run in lead/follow to recycle flow. The lead is switched manually by a switch on the control panel. The pumps are monitored for product flow, recirculated flow, and product quality. The readouts are displayed on the main control panel. In AUTO, the water transfer pumps will start automatically and shut down on a low-low tank level alarm.

NOTE: There are two city water booster pumps in a shed north of the water treatment system, while not a part of the water treatment system, the system depends on these pumps running. If the booster pumps shut down a light near the shed roof will come on.

Alarms

Local control panel alarms. The following alarms register on the reverse osmosis (RO) system local control panel:

- LOW RO FEED WATER PRESSURE (PSL-4 13). If the RO unit is running and the feed water pressure (PSL-418) does not pass set point (20 psig) for 30 seconds, the RO shuts down.
- HIGH RO PUMP DISCHARGE PRESSURE (PAH-417). If the RO unit is running and the feed water pressure (PIT-422) exceeds set point (300 psig) for 1 second, the RO shuts down.
- HIGH RO MEMBRANE DIFFERENTIAL PRESSURE (PDAH-426). If the RO unit is running and the differential pressure from PIT-422 and PIT-423 exceeds set point (20 psig) for 5 seconds, the RO shuts down.
- HIGH RO PRODUCT PRESSURE (PAH-419). If the RO unit is running and the feed water pressure (PT-429) exceeds set point (50 psig) for 10 second, the RO shuts down.
- LOW RO REJECT FLOW (FAL-401A). If the high pressure pump is running and the RO reject flow (FE-403B) exceeds the low alarm set point (2 gpm) for 90 seconds, the RO shuts down.
- HIGH RO REJECT FLOW (FAH-401A). If the high pressure pump is running and the RO reject flow (FE-403B) exceeds the high alarm set point (3 gpm) for 10 seconds, the RO shuts down.
- LOW% REJECTION (AAL-401A). If the high pressure pump is running, and the percent rejection (FE-403A/B) falls below the set point (90 percent for 90 seconds an alarm registers.
- LOW PRODUCT CONDUCTIVITY (AAI-401B). If the high pressure pump is running and the product conductivity (CE-417B) falls below the low alarm set point for 60 seconds, an alarm registers.
- LOW RO PRODUCT FLOW (FAL-401B). If the high pressure pump is running and the RO product flow (FE-403A) exceeds the low alarm set point (3 gpm) for 90 seconds, the RO shuts down.
- HIGH RO PRODUCT FLOW (FAH-401B). If the high pressure pump is running and the RO product flow (FE-403A) exceeds the high alarm set point (4 gpm) for 10 seconds, the RO shuts down.
- CDI PRODUCT QUALITY (AAL-437). If product quality falls below the set point (2 Mohm) for 10 seconds, the system will go into recirculation until quality is met.

Main control panel alarms[1]. To reset the alarm press RESET.

- LOW LOW TANK LEVEL. If the deionization storage tank level (LALL-402) falls below the low-low level set point (20 percent) for 10 seconds, an alarm registers and the transfer pumps are shut down.

DCS water treatment system alarms. Several alarms are relayed from the water treatment

1. WHERE is this control panel

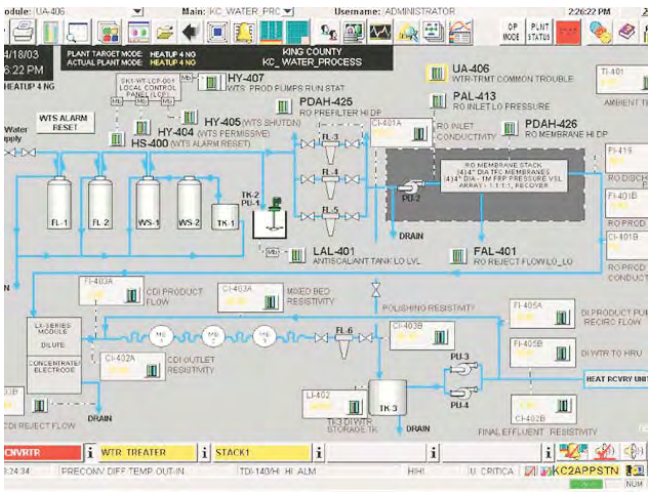
system PLC to the fuel cell DCS. Many items can also be monitored from the water treatment system PLC operator interface unit

MOD BUS sends the following alarms to the DCS:

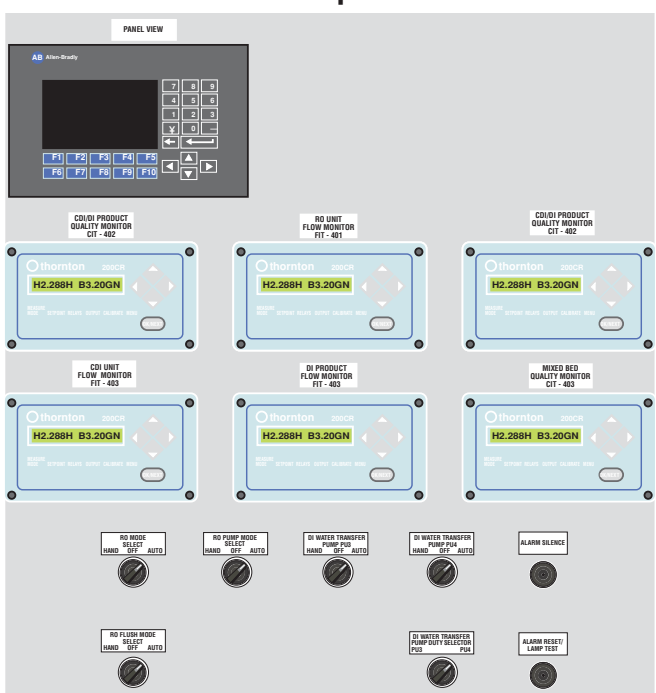
- ANTI-SCALANT TANK LOW LEVEL (TC) shuts down the system.
- RO PRE-FILTER DIFFERENTIAL PRESSURE HIGH (>10 psig) shuts down the system.
- RO FEED PRESSURE LOW (<20 psig) shuts down the system.
- RO MEMBRANE DIFFERENTIAL PRESSURE HIGH (>20 psig) shuts down the system.
- RO PRODUCT PRESSURE HIGH (>50 psig) shuts down the system.
- RO PRODUCT FLOW LOW (<3 gpm shuts down the system.
- LOW CDI RESISTIVITY (TC) flow is diverted from the deionization tank.
- LOW SDI UNIT RESISTIVITY (TC).
- LOW FINAL RESISTIVITY AT DI TRANSFER PUMPS (TC).
- LOW DI WATER FLOW AT CDI PRODUCT LINE. (TC).
- LOW LOW DI STORAGE TANK LEVEL. The deionization storage tank level has dropped to 20 percent. Shuts down the transfer pumps.

Power outage

After a power outage the water treatment system must be restarted. See *Section 6, Restarting after a power loss, page 6-85*

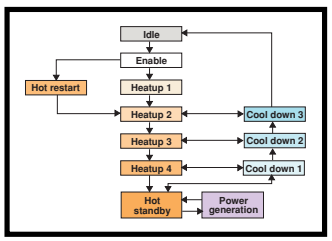


KC water process



Water system LCP (panel 28)

Reference



5.11 Overview of the Digester Gas Conditioning Controls

The digester gas conditioning system treats and conditions the raw digester gas for use as anode fuel. The raw digester gas passes through a knockout drum to remove liquids mixed with the gas and is then fed to a compressor. The compressed gas is cooled in a water-to-air heat exchanger and passed through a second knockout drum to remove condensed liquids. The cooled dry compressed gas is sent through a SulfaTreat bed for bulk sulfur removal. The gas then passes through two gas polishers (potassium hydroxide- [KOH] impregnated activated carbon beds) to remove trace sulfur compounds. The impregnated KOH also helps remove COS, SO_2, and traces of siloxanes (polymers) and organic chlorine compounds.

The cooling water and condensed liquids are sent to the plant headworks. The SulfaTreat bed is made of ferric and triferric oxides on an inorganic substrate. Both it and the gas polisher sorbant are considered environmentally benign.

A low-pressure sludge gas (LSG) header pressure alarm (4 inches W.C) from the South Treatment Plant gas system places the digester gas conditioning system in standby and shuts down the compressor.

Compressor enclosure

The compressor, the aftercooler, and the knockout drums are housed in a heated enclosure that is kept at 40°F by a unit heater with a local thermostat. The enclosure temperature is monitored, and high-high and low-low alarms register at the DCS. A fan comes on _____.

WARNING

Personal toxic gas meters set for hydrogen sulfide must be worn when entering this enclosure.

The enclosure also has two hydrogen sulfide detectors (AE-801/2), two ultraviolet and infrared flame detectors (AE-820 and AE-830), and a combustible gas detector AE-805 located1 foot below the ceiling.

- A fire alarm registers at the fire panel, shuts down the fuel cell, and activates a horn and flashing red beacon.
- A hydrogen sulfide level of 5 ppmv registers at the fire panel. A H_2S level of 15 ppmv shuts down the fuel cell and activates a horn and flashing yellow beacon.
- An LEL of 25 percent registers as an alarm at the fire panel. An LEL of 60 percent shuts down the fuel cell and activates a horn and flashing white beacon.

Raw digester gas supply

A manual isolation valve is located on a heat-traced line east of the compressor. This manual valve must remain open at all time to ensure a relief path is available on shutdown. This valve is normally locked open.

Control strategy. The automatic isolation valves (two in series) open when the gas conditioning system is being used, and close on fuel cell system shutdown. If the valves close while the fuel cell is using conditioned digester gas as anode fuel, an alarm registers and the fuel cell shuts down.

Feed knockout drum

Knockout drum (800-SP-101) removes entrained liquids from the gas. The drum has a pressure relief valve set at 50 psi, and is locally monitored for temperature, pressure, and differential pressure.

Control strategy. The liquid level inside the drum is controlled by a level transmitter (LE-825) acting on the drain solenoid valve (LV-825). The valve opens on high level and closes on low level. On a high-high level, an alarm registers and the compressor shuts down. On low-low level, an alarm registers and a second solenoid valve on the drain line closes. A check valve down stream of the pair of drain valves prevents backflow into the drum. There is also a high high level switch

(LS-821) that shuts down the fuel cell, if the fuel cell is using digester gas as anode fuel.

Digester gas compressor

Gas at about 0.1 psi and 80°F is fed to the digester gas compressor.

Control strategy. The compressor speed is controlled by PC-819 which varies the speed of the compressor to maintain a set point of 28 psi. If the compressor is running at minimum speed, a bypass valve (PV-819) on the discharge is opened and the gas is sent back to the inlet of the feed knock out drum to maintain the discharge pressure set point (28 psi).

Alarms. The compressor discharge has high and low pressure alarms. High pressure causes the pressure relief valve (PSV-825) to open at 55 psig and shuts down the compressor. High high and low-low pressure shuts down the fuel cell system, if the fuel cell is using digester gas as anode fuel.

A high temperature also causes the compressor to shut down.

A compressor VFD fault registers as a common trouble alarm.

A low pressure sludge gas (LSG) header pressure alarm from South Plant puts the fuel cell in Hot Standby. A low low LSG header pressure alarm shuts down the fuel cell.

Jacket water flow. The compressor jacket water flow is kept at a constant temperature by temperature control valve TCV-831. The jacket water system uses C2 water.

Aftercooler

The compressed gas is cooled in the digester gas aftercooler (800-HX-101) a water-to-gas heat exchanger to 85°F.

Control strategy. The cooling water is C2, and the flow rate is modulated by control valve TCV-833 to control the temperature of the gas leaving the aftercooler. A manual isolation valve (XV-801) is closed during system shut downs.

Discharge knockout drum

The cooled compressed gas enters the discharge knockout drum (800-SP-102) to remove condensed water. The drum has local gauges for inlet pressure and pressure differential and a pressure relief valve (PSV-815) set at 50 psig.

Control strategy. The level control is similar to the feed knockout drum. The level controller is LC-826, the first solenoid drain valve is LV-826, and the second valve is LV-827.

Alarms. The alarms are similar, however, a high-high liquid level also closes the aftercooler water supply valve (XV-801) if the high level is from a leak in the aftercooler. A high high level switch (LS822) will trip as well.

High temperature downstream of the discharge knock out drum puts the fuel cell in a PPR if the fuel cell is using digester gas for anode fuel.

High efficiency oil filter

The gas then goes through a a high efficiency oil filter that removes entrained lubrication oil from the gas.

SulfaTreat

The compressed dry gas is then fed to the SulfaTreat vessel (800-RR-101) to remove hydrogen sulfide (H_2S) to less than 10 ppmv. The H_2S is removed chemically. The vessel is monitored locally for the bed differential pressure and the discharge pressure. The vessel has a pressure relief valve (PSV-816) set at 50 psig. The valve vents to the digester gas feed line upstream of the supply isolation valve (XV-820A). The vessel has sample ports and a manual drain for condensation.

The vessel is drained of concentration once a day.

LEL and toxic gas. Two H_2S detectors are located near the SulfaTreat vessel. A hydrogen sulfide (H_2S) level of 5 ppmv registers as an alarm at the fire panel. An H_2S level of 15 ppmv shuts down the fuel cell and activates a horn and flashing yellow beacon.

Digester gas polisher

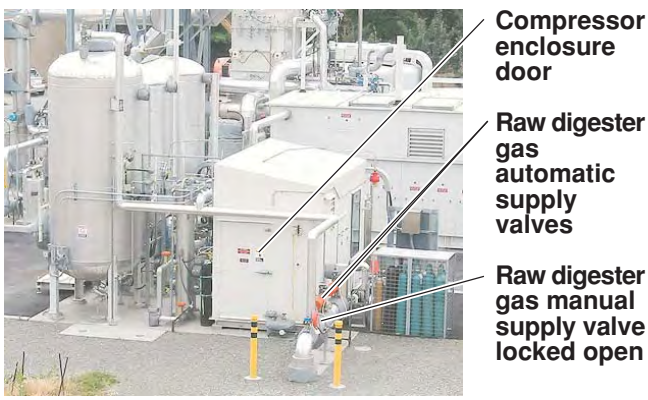
The discharge from the SulfaTreat vessel goes to the digester gas polishers (800-RR-102A/B) to remove contaminants and any remaining sulfur to a level of less than 0.1 ppmv.

Control strategy. The gas polishers run in series and valves are manually configured to place them in lead/guard. The lead position is switched when the sulfur concentration of the discharge indicates the bed is used up. The guard is then valved to the lead position and the lead polisher is isolated, depressurized, and purged with nitrogen. The

sorbant is replaced, then the polisher is purged with nitrogen, and repressurized with desulfurized gas from flow control valve FCV-812. The vessel is then returned to the guard position.

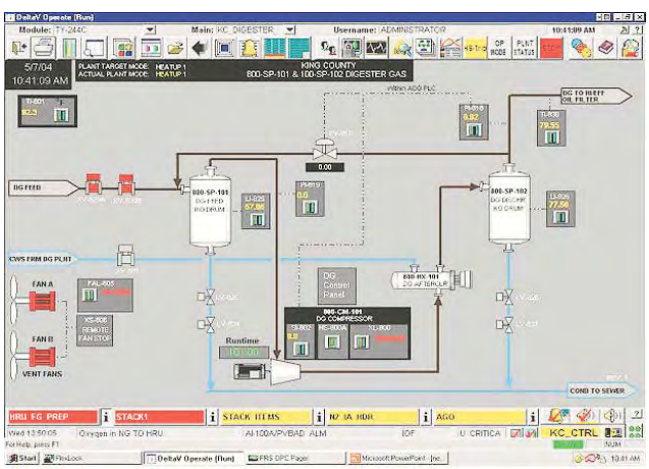
Monitoring. Each gas polisher is monitored locally for bed pressure differential and vessel pressure.

The vent lines open to the atmosphere and a pressure gauge is located between the pair of isolation valves to detect leaks in the vent line valve. The lines are heat-traced at 90°F to prevent condensation in the lines. (Portable nitrogen cylinders are used for purging.)

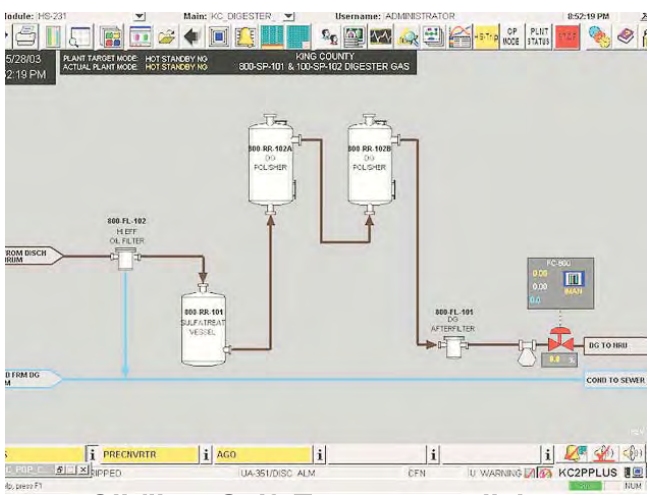


Digester gas preparation system

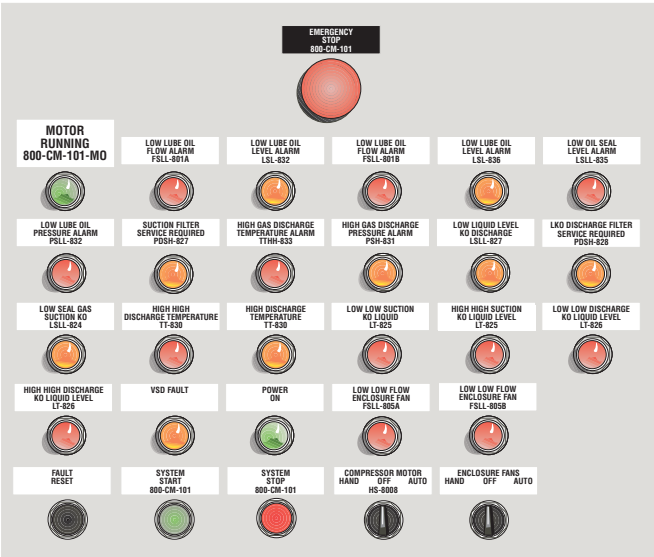
Digester gas preparation system



Knockout drums and compressor screen

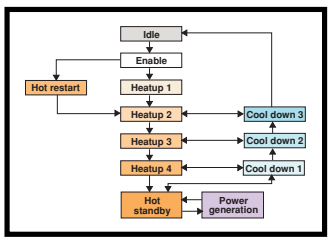


Oil filter, SulfaTreat, gas polisher and after filter screen



Digester gas preparation system panel

Reference



5.12 Enabling the Fuel Cell System for Startup

During startup, the fuel cell stack module is heated up from ambient temperature to a standby operating condition (about 1,100°F) while the gas environments are maintained in the fuel cell anodes and cathodes. The fuel cell is then ready to start generating power or to be placed in hot standby. In hot standby, the fuel cell can ramp to full power generation within 8 hours.

During plant startup, "natural gas" or scrubbed digester gas is used to fire the oxidizer and heat up the plant.

NOTE: The FuelCell Energy (FCE) operator is required during all plant startups (from a cold condition or from a warm condition).

Nitrogen bottles must be replaced before starting up or restarting the plant, and the FCE operator must witness light-off of the oxidizer burner.

Startup skid

A startup system skid (including a startup heater 200-HF-101 and startup blower 200-BL-102) must be put in service to warm up the fuel cell stack module. Once the fuel cell is warmed up, an FCE operator must shut off and physically isolate the startup system skid, electrically from the fuel cell balance of plant (panel 7) and mechanically by closing the fuel supply and closing the inlet and outlet valves.

DANGER

Before a first-time startup and after maintenance that might have allowed air to enter the anode side piping or equipment, the following must be done before heating up the fuel cell:

- *Purge the fuel gas piping and fuel cell anodes (first-time startup only) with nitrogen gas using the nitrogen tie-in at the desulfurizer. This will purge and inert all equipment in the anode fuel system.*
- *Confirm that the cold gas desulfurizers are filled with natural gas.*
- *Confirm that the SulfaTreat vessel and digester gas polishers are filled with digester gas if the plant will use digester gas for anode fuel.*

Enabling the fuel cell system for startup

1. **Verify that electric power is available.**
2. **Boot up the computers and verify that plant process information is displayed.**
3. **Verify that the plant shutdown relay is energized and that field power is available to all DCS outputs.**
4. **Verify that no combustible gas alarms, heated enclosure temperature alarms, or plant shutdown alarms are activated.**

Enabling process and utility feed streams

1. **At the natural gas supply, verify that the battery limit manual block valve is open and natural gas is available at 15 to 50 psig.**
2. **Check the digester gas conditioning system.**
   a) Verify that at least one desulfurizer compartment fan must be running.
   b) Verify that the battery limit manual valve is open and digester gas is available at the plant battery limit (if the plant is using digester gas for anode fuel).
   c) Check the level in the lube oil day tank for digester gas compressor 800-CM-101.
   d) Check that the cooling water battery limit manual valve is open and cooling water is available at the plant battery limit (if the plant is in digester gas mode).
3. **Start the water treatment system.**
   a) Check the city water supply battery limit manual valve is open, the booster pump is running, and raw city water is available at 50 to 65 psig.

b) Start up the water treatment system by sending it DCS permissive signal HY-404.

c) Verify that the treated water level in the product water storage tank is acceptable, and that the common trouble alarm UA-406 is not in alarm. (Control panel in panel 28, Skid 1)

4. Start the instrument air system.

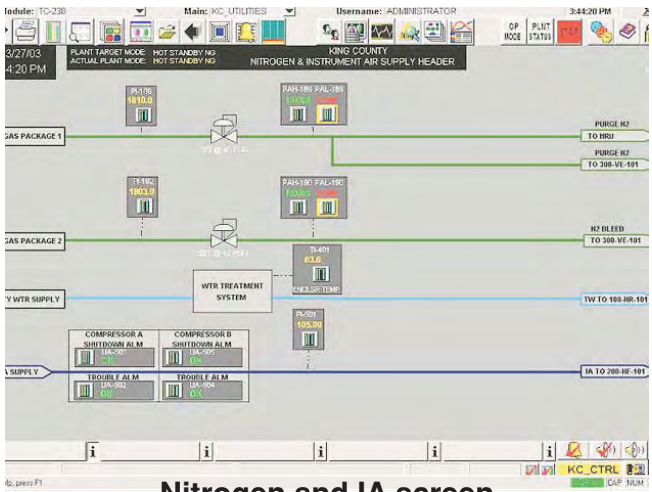
Start up the instrument air compressor and dryer at the local panels. Verify that trouble alarms UA-502 and UA-504 are not activated and that instrument air is available at acceptable pressure (PI-501 is not in alarm). (Side B and C of skid 2).

5. Check the nitrogen supply system

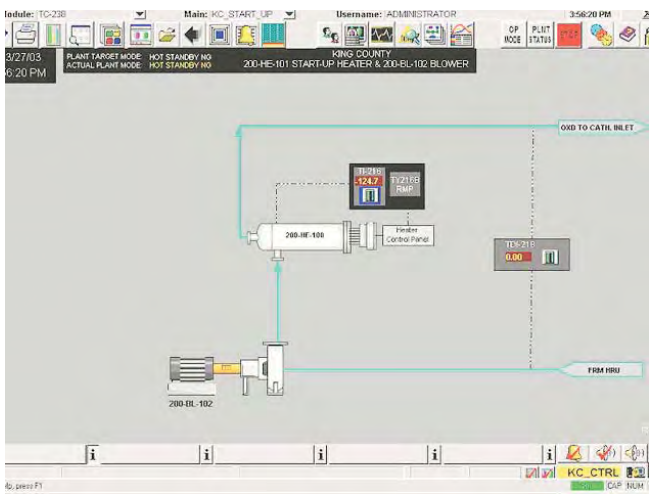
a) Check that the nitrogen bottles are full and nitrogen is available to the nitrogen gas supply system and that neither system is in low pressure alarm. A DCS interlock prevents plant heatup if either nitrogen system is in low alarm. The N2 bottle racks may remain isolated until just before gas and water are enabled. (Skid 1 panels 1 and 2)

b) Verify that nitrogen purge valves XV-1 91 and XV-282 and nitrogen bleed valves XV-280 and XV-284 are closed.

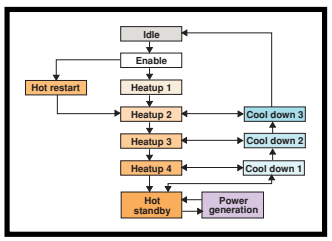
Insturment air system (side C, skid 2)



Nitrogen and IA screen



Startup skid screen



5.13 Heating Up the Fuel Cell Stack

The heatup sequence proceeds through four stages, based on the temperature of the oxidant gas entering (cathode inlet) or leaving (cathode outlet) of the fuel cell stack. The heatup sequence can be halted at any stage due to alarms. The system will wait until the alarms clear before continuing the heatup sequence. From Hot standby (essentially Heatup 4), the fuel cell can start power generation and ramp to full power about 1 mW net power within 8 hours. Screens on the DCS provide detailed checklists for transition to the next stage. For detailed procedures, *Section 6, KCPP Startup to Hot Standby (NG), page 6-14* and *Section 6, KCPP Power Generation, page 6-34*.

Heatup 1

The startup system skid does the initial heating of the fuel cell by recirculating a progressively warmer air stream through the fuel cell cathodes. This keeps the water vapor in the oxidant stream from condensing in the cold fuel cell stack. The oxidizer effluent during this stage contains too much water vapor to provide this warm-up air.

- The startup skid blower and heater are used until the stack's cathode outlet temperature is greater than 250°F, then it is shut down.
- During this stage, the electric jacket heater preheats the preconverter to operating temperature.

NOTE: The startup system skid operates at temperatures below 300°F. The skid's interconnecting piping is manually aligned and must be manually isolated from the cathode oxidant piping at the end of this stage of startup. The startup skid's power is also turned on at the beginning of startup and shutoff, at the balance of plant after shutdown and isolation.

Heatup 2

The oxidant supply system supplies a large flow of progressively warmer air through the fuel cell cathodes until the cathode inlet temperature is 880°F. This heat up rate is 15°F per hour.

- The oxidizer's natural gas burner is fired to provide the heat and the air blower runs at 3500 scfm to minimize the temperature differential across the fuel cell cathodes.
- The oxidizer's catalyst section is heated up to operating temperature using the oxidizer's tertiary air controls.
- The electric jacket heater still preheats the preconverter to operating temperature.
- Hot cathode exhaust air passes over the coils of the humidifier and fuel superheater (located in the heat recovery unit).
- Once the cathode inlet temperature is at 700°F, the oxidizer catalyst is at above 1000°F, and after the preconverter catalyst has reached its operating temperature, a small flow of natural gas and water is generated in the fuel gas preparation system and sent through the anodes. This protects the anodes from being oxidized. As this fuel exits the anodes, it passes through the oxidation catalyst section to remove and hydrogen (H2) or methane (CH4) in the exhaust gas.

Heatup 3

The oxidant supply system continues to supply 3500 scfm of progressively hotter air through the fuel cell cathodes until the cathode inlet temperature is up to 990°F.

- The heatup rate (12°F/hour) is less at this stage to limit the stress on the cells because the electrolyte salts are melting.
- The reducing gas flow is maintained on the fuel cell anodes.

Heatup 4

The oxidant supply system continues to supply 3500 scfm of progressively hotter air through the fuel cell cathodes until the cathode inlet temperature is up to 1,110°F.

- The heatup rate returns to 15°F/hour at this stage.
- The reducing gas flow is maintained in the fuel cell anodes.

Hot standby

The transition to hot standby is in name only, the controls and set points are the same as Heatup 4.

The fuel cell can also be tripped to hot standby either automatically as a plant protective response (PPR) or manually by the operator.

- TC-238 controls the oxidizer burner's firing rate to keep the oxidizer effluent at 1,110°F.
- FC-210 maintains the air flow at 3500 scfm.
- The tertiary air flow controller TC-245 has closed the valves.
- The anode fuel gas flow rate is maintained at the same rate that was used during heatup to maintain a reducing environment in the anodes.

Power generation

To start power production, the power conditioning system and electric grid system must be available and capable of accepting power.

The first step in starting power generation from the fuel cell stack is to start drawing a minimum current from the stack using the power conditioning system (PCS). This current must be enough to synchronize the P05 to the power grid.

Once power production has started, power generation and fuel flow ramp up at the same time. This maintains the process, electrical and control system constraints, and operating windows.

The FuelCell Energy operator will choose one of two pre-defined power levels: load reduced or load rated.

The DCS then starts to ramp up power production. The DCS calculates the instantaneous power that is generated from the voltage and current signals and determines whether to increase or decrease fuel flow to the fuel cell stack module.

Based on the fuel flow measurement, the DCS also calculates the maximum allowable DC current that may be drawn from the fuel cell stacks. The power ramp and fuel flow is then coordinated by the DCS until the target power level is reached.

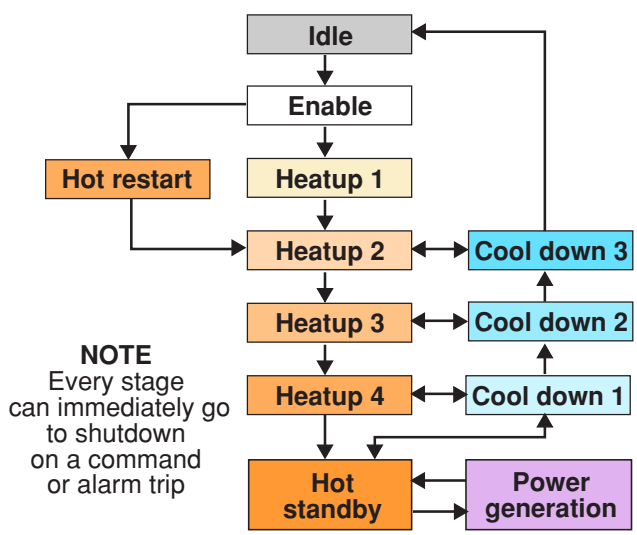
To prevent over consuming the available fuel and to minimize the effects of power generation, the fuel utilization (FU) is set to a low value (about 50 percent). During power ramp up, to maintain the correct steam-to-carbon ratio, the water flow increase will lead the natural gas fuel flow increase.

During the ramp up, the air flow to the oxidizer is controlled by the total air flow controller (TC-236). The DCS determines the total air flow based on the demanded current (DEMANDED DC). This set point may be trimmed (plus 1 to 10 percent) by the cathode inlet temperature controller (TC-243) and constrained by the minimum air-to-fuel ratio controller (FY210C) and the oxidizer outlet controller (TC-238).

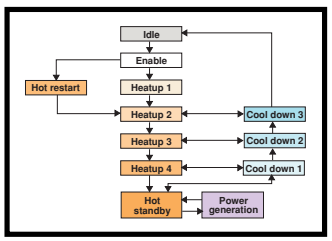
When the plant reaches a net AC power production level of about 750kW, the anode exhaust stream can provide enough heat to maintain the fuel cell stack temperatures without the oxidizer natural gas burner. Until this happens the cathode temperature is controlled by TC-238, which adjusts the burner fire rate. After the main burner is turned off the cathode temperature is controlled by trimming the air flow, this is done with TC-243.

Transition from load reduction back to hot standby

As the demanded load ramps down to less than about 750 kW the fuel cell stack is no longer produces enough heat to maintain its own temperature so the main burner on the oxidizer relights. As power demand continues to drop and the power control system (PCS) continues to reduce the power output eventually it reaches a point where the DC disconnects open and the load demand is at zero. This effectively puts the fuel cell system back in hot standby.



The control system uses several modes to keep the fuel cell system active. Normally the system is either heating up, cooling down, in hot standby, or generating power



5.14 Normal Fuel Cell Shutdown

A normal shutdown is manually started from the DCS operator interface unit. All utilities and equipment must be available for this staged shutdown. The fuel cell stack module is gradually cooled from the operating temperature to less than 300°F. All gas environments are maintained in the fuel cell anodes and cathodes. A plant cooldown is normally started while the fuel cell system is in hot standby, but it can also happen from any stage of plant heat up or after a plant restart.

The cooldown sequence is the reverse of the heatup process, but does not need the startup skid. When starting from hot standby, the cooldown goes through three stages based on the temperature of the oxidant gas (cathode inlet temperature) being fed to the fuel cell stack module. If cooldown is started after an unfinished heatup sequence or a restart, the DCS first checks the fuel cell stack module temperature. It then selects the cooldown stage based on the temperature.

Cooldown from hot standby

When cool down starts, the oxidizer air flow is increased to 3,500 scfm; it is held there by controller FC-210 until cool down is over. The flow controller monitors the oxidizer total air flow and adjusts the secondary air flow valve (FV-210) to compensate for changes in primary or tertiary air flow. The oxidizer effluent temperature is also kept at 1,110°F. Temperature controller TC-238 controls the oxidizer burner's firing rate by providing a set point to the burner fuel (FC-208) and air flow (FC-230) controllers. The air flow changes always lag fuel reductions so that the burner will fully burn the fuel.

Cool down 1. The oxidant supply system cools the fuel cell stack from 1,110°F to 990°F at 15°F per hour by passing a large flow of progressively cooler effluent gas through the fuel cell cathodes. The oxidizer's natural gas burner controls the heat to maintain the ramp down rate by controlling the main burners fuel flow rate.

A small flow of reducing gas going through fuel cell anodes protects them from being oxidized. The reducing gas reacts as it passes through the oxidation catalyst section. The fuel gas preparation system uses natural gas, water, and heat recovered from the cathode exhaust gas to generate the reducing gas and heat it to the required temperature.

Cooldown 2. The cooldown continues until the cathode inlet temperature is 880°F at the rate of 12°F per hour. The cooling rate is reduced the electrolyte solidifies or freezes to limit the stress on the fuel cells. The oxidant supply system still supplies the large hot air stream for the fuel cell cathodes, and the reducing gas flow for fuel cell anodes.

Cooldown 3. The cooldown resumes the initial ramp rate of 15 °F per hour. The oxidant supply system still supplies the large hot air stream for the fuel cell cathodes. The reducing gas flow for fuel cell anodes continues until the fuel cell stack falls below 650°F, the preconverter inlet fuel gas temperature falls below 550°F, or the preconverter internal temperature falls below 500°F. The fuel gas preparation system then shuts down and is purged with nitrogen. The purge prevents carbonyl[1] and condensation from forming as the fuel cell cools.

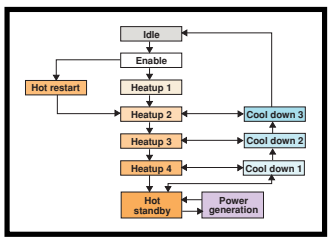
The cooldown continues until the oxidizer reaches its minimum firing condition and an effluent temperature of ≤ 286°F. The oxidizer effluent is then held at this temperature and passed through the fuel cell cathodes until the cathode outlet temperature drops below 300°F. At this time the plant transitions to IDLE, with the main burner off, and the air blower off. The fuel cell stack will now continue to cool passively by natural circulation of air.

Shutdown hardwire button. When the SHUTDOWN HARDWIRE button is pressed, the DCS switches to off mode. The DCS remains on and plant process information can be displayed, but all DCS outputs are off. The fuel cell stack module continues to cool down to ambient temperature by natural convection. The plant is then shutdown and secured.

1. Carbonyls, both aldehydes and ketones are mainly formed by the oxidation of alcohols

Normal shutdown

Natural gas supply isolation valve A (XV- 103A)	Close
Natural gas supply isolation valve B (XV- 103B)	Close
Natural gas flow control valve (FV- 117)	Close
Natural gas geater (100-HE-IOI) permissive lost	Off
Heat recovery unit (HRU) fuel humidifier damper (TV-120 A)	Close
HRU fuel humidifier bypass damper (TV- 120 B)	Close
Preconverter jacket heater temp controller (TC- 130)	Disable
Treated water flow control valve (FV- 131)	Close
Nitrogen purge valve at humidifier inlet (XV- 191)	Open *
Startup heater 200-HE-I 01 temp controller (TC- 217)	Off
Air blower 200-BL-1 01 (HS- 224)	Stop
Oxidizer 200-HE-IOI (burner mng sys) (HS-231 A)	Stop
Oxidant bypass valve around Stack Module (HV-240)	Close
Air blower discharge valve (XV- 241)	Close
Anode fuel gas to stack module iso valve (XV 247 A)	Close
Anode fuel gas vent valve (XV- 247 B)	Open
Anode exhaust gas vent valve (XV- 260)	Open
Anode exhaust gas block valve (XV- 262)	Close
Nitrogen bleed valve at fuel gas inlet to stack module (XV- 280)	Open
Nitrogen purge valve at fuel gas inlet to stack module (XV- 282)	Open *
Nitrogen bleed valve at oxidant inlet to stack module (XV- 284)	Open
Power conditioning system 600-PC-401 (XS- 351 B)	Stop
Digester gas flow control valve (FV- 800)	Close
Digester gas compressor 800-CM-i 01 (HS- 800 A)	Stop
Digester gas supply isolation valve A (HV- 820 A)	Close
Digester gas supply isolation valve B (HV- 820 B)	Close



5.15 Trip Recovery, Rapid Restart, and Hot Restart

Once the fuel cell trips and is starting to cool down it can be restarted using one of three ways depending on the current temperature of the fuel cell stack. The current setting on the fuel cell system are show on the King County Plant Setting screen. In all cases the problem that tripped the fuel cell must have been corrected, and documented, the water treatment system, the instrument air system, and the safety and fire protection systems must be ready and running, and the FuelCell Energy operator must be consulted. If the main oxidizer burner has shutdown only the FuelCell Energy operator can relight the burner. For detailed procedures to trip recover the fuel cell system see *Section 6, KCPP Trip Recovery Procedure, page 6-42*. For detailed procedures to rapid restart the fuel cell system see *Section 6, Rapid Restart Procedure, page 6-48*. For detailed procedures to hot restart the fuel cell system see *Section 6, KCPP Hot Restart Procedure, page 6-46*.

Hot restart

Hot restart allows the operator to bypass the Heatup 1 and startup the fuel cell system without using the startup skid equipment. The system is started at heatup 2 and from there progresses like any other heatup. The FuelCell Energy (FCE) operator can “hot restart” the fuel cell after a shutdown as long as the fuel cell stack module temperature is still above 150°F but less than 500°F.

CAUTION

Only a FCE operator may light the oxidizer burner.

Because this procedure requires an oxidizer burner “light off”, only the FCE operator can do this procedure. All utilities and equipment must be “ready” and the problem that caused the trip must be resolved. Then the AGO pilot is lit, then once air flow from the blower is up to 2,000 scfm the main AGO burner is lit, and oxidizer outlet temperature controller TC-238 controls the ramp up at 15°F per hour. The airflow continues to increase until it reaches set point of 3,500 scfm.

This procedure is used once the plant is in IDLE. The fuel cell stack module must be above 150°F on TI 240, and less than 500°F on TI 320A. The nitrogen system must be at pressure, the water treatment and instrument air systems must be ready, and all alarms must be cleared from the fire panel. When this procedure is finished, you enter the plant heatup sequence at HEATUP-1 NG.

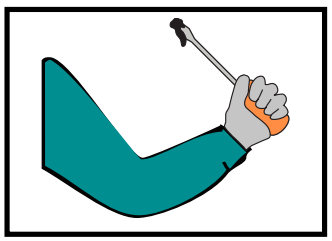
Rapid restart

For this procedure the plant must be in Idle, the fuel cell stack “best temperature” is greater than 500°F as determined by the FCE operator. There are actually two ways to rapid restart the fuel cell, with and without anode cover gas. The anode cover gas is used if fuel had been sent to the fuel cell stack before the shutdown.

The goal of Rapid Restart is to return the AGO outlet temperature to the fuel cell temperature as quickly as possible without overshooting the mark.

SECTION 6
Operating the Fuel Cell

6.1 Operators Notes—Normal Operation 6-2
6.2 Operators Notes—Trip Recovery 6-6
6.3 Operators Notes— the Anode Cover Gas System and Nitrogen Purge 6-10
6.4 Operators Notes—Monitoring Cell Group Voltage Deviation 6-12
6.5 KCPP Startup to Hot Standby (NG) 6-14
6.6 Startup to Hot Standby DG 6-24
6.7 KCPP Power Generation 6-34
6.8 KCPP Trip Recovery Procedure 6-42
6.9 KCPP Hot Restart Procedure 6-46
6.10 Rapid Restart Procedure 6-48
6.11 KCPP Shutdown Procedure 6-54
6.12 Using the Startup Skid 6-60
6.13 Operating the Fuel Preparation System 6-62
6.14 Changing Desulfurizer Lead and Guard Positions 6-66
6.15 Purging the Desulfurizer and Preconverter with Nitrogen 6-70
6.16 Replacing the Filter Media on the Fuel Preparation System 6-74
6.17 Operating the Nitrogen System 6-78
6.18 Operating the AGO System 6-82
6.19 Operating the Water Treatment System 6-92
6.20 Operating the EBOP 6-96
6.21 Miscellaneous Systems 6-102
6.22 Initial Valve Lineup Checklist 6-104



6.1 Operators Notes—Normal Operation

These operators notes have been provided by FuelCell Energy, Inc. As much as possible they have been edited for grammar only and reformatted. They are part of the information needed to operate the fuel cell system. Read these notes before trying any of the procedures that follow in this section. In this section the term "plant" refers to the fuel cell system, not the wastewater treatment plant.

In General

When bringing the plant up in temperature you should be operating through the Operation Mode screen: The software does most of the valve and major equipment operations.

Get the preconverter jacket heater started as early as possible. When the preconverter jacket heater is on, it needs to be purged with N2 daily.

Verify the fuel line heat trace and anode inlet heat trace are on.

Heatup 1:

This mode is not used often, but it will be needed when we integrate the fuel cell. It provides moisture free heatup and better control of the temp ramp at low temperatures.

When we decide to preheat the unit using the startup heater skid, we will stop the heatup before the cathode outlet temperature reaches 300°F. To protect the blower the return temperature to the blower must remain less than 300°F.

Hot Restart:

This mode will bypass Heatup 1 mode. The startup heater/blower system is not used.

The temperature at TI-320A is >150 F. It is important that the ramp controllers for the oxidant out (T-238B), and the catalyst (T-244C), are setup correctly. The controllers should be enabled, tracking set to OFF, and loaded with the current set points and ramp end set points.

When the checklist opens the following options should display:

Rapid Restart (used when fuel cell is >500°F, TI-320A) and Anode Cover Gas (if plant was gas and water enabled before the trip).

(For Rapid Restart and Anode Cover Gas, "Operators Notes—Trip Recovery" on page 6-6, and "Rapid Restart Procedure" on page 6-48.

Note: The mode checklist shows which heatup level the plant can be returned to, based on the fuel cell temperature.

The operating mode control screen shows that you can choose any level (i.e. heatup 2, 3 or 4) based on the temperature, BUT if you choose 3 or 4 the equipment must be manually restarted. ***Therefore, start at heatup 2 and allow the DCS to sequence the rest of the heatup, one step at a time.***

Heatup 2, Rapid Restart not selected

To change to Heatup 2 the following things must happen:

- The startup heater and blower must be shutdown. This must be done manually at the local control panel.
- The oxidizer air blower is started and the AGO burner is lit.
- The fuel cell bypass valve, HV-240 opens.
- The air blower discharge valve opens.
- Currently the total air flow controller (FC-210), changes to auto with a set point of 900 scfm.
- When the differential pressure alarm (PDAL-233) clears, the 2 minute purge should start. This is done locally by pressing the system STOP/RESET push button and then pressing the system RESTART pushbutton.
- Once the purge is done, the pilot lights off. When the FireEye sees a flame the total air flow controller (FC-210) set point changes to 3500 scfm and the blower ramps at 2 scfm/sec.
- When FC-210 reaches 2000 scfm the main burner fires.
- Now TY-238B begins its ramp at 15°F/hr., by increasing the output signal sent to the AGO burner gas flow control valve (FC-208). Monitor the temperature ramp rate verifying

actual rate and watching for any ramp hold conditions.

- When the cathode inlet temperature (TC-238), exceeds the cathode outlet temperature (TC-240), fuel cell bypass valve (HV-240) will close automatically but it has been set to close very slowly. It will take about 30 minutes.
- Once the catalyst out temperature (TC-244) reaches 500°F, the catalyst heatup ramp rate will increase the catalyst temperature to 1010°F at 30°F per hour by modulating the tertiary air valves. (It takes about 17-hours). (The valve opens to increase the catalyst temperature and closes to decreases the catalyst temperature.)
- Monitor the catalyst temperature ramp rate, verify the actual rate and watch for any ramp hold conditions.

  Currently the catalyst out temperature (TC-244) is the average of TI-244A, B and C. Oscillations occur if trying to ramp up using only the highest TI-244 input (normally B).

  The cathode inlet heat up ramp, TY-238B, will stop when the oxidant out temperature is 700°F, if the gas and water can not be enabled. The following must be met before water and fuel gas can be enabled: TI-142 >600°F, TC-244 >1000°F and TI-125 >500°F).

Monitor the following during heat up

Oxidant temperature ramp rate is monitored by checking the ramp rate and watching for ramp hold conditions.

It is critical that gas and water are enabled and maintained above 700°F. If the anode is exposed to oxygen it will oxidize, which is bad, so gas and water flow are started in the fuel cell at 700°F to maintain a reducing (as opposed to an oxidizing) gas flow on the anode side.

Enabling gas and water is one of the critical points the operation. The Lead should hold a briefing, and the entire shift should participate.

Water flow must start first. The most important thing to do is to be sure that water flow starts first and that the steam-to-carbon ratio is maintained at greater than 2:1 at all times; the steam to carbon ratio starts at 8:1

If gas flow starts without water. If gas flow starts without enough water, you should take manual control of valve FV-117 and close it. If you get zero gas flow, then take manual control of valve FV-131 and close it.

If the gas flow is not reduced to zero keep enough water flow to maintain an 8:1 steam-to-carbon ratio or trip the plant to isolate all the gas flow (supply valves XV-103A and B will close).

The gas valve responds very slowly to a demand for flow. It generally took 15 minutes to open the valve from fully closed to about 13% open, the point when flow is first shown by flowmeter FE-117. To decrease this time the "LO LIM" setting for FV-117 was changed to 10%. This means that the valve is 10% off its closed seat when it stops driving closed, and while not fully close, there is no flow.

Normal water and gas flow valve settings. The water valve is normally about 23% open to maintain 85 scfm flow. The the gas valve is normally open 16% to maintain 10 scfm flow.

NOTE: The water flow set point is set based on the equation (gas flow) x (S:C, steam-to-carbon ratio) x (TCC, total carbon content). The total carbon content is calculated by the DCS based on the gas composition that is input on the Natural Gas Input screen.

Heatup 3

This part of heatup (880–960°F) is when the electrolyte melts so the heatup ramp rate is reduced to 12°F/hr. at TY-238B.

When the burner starts cycling. During heatup 3, the tertiary valve gets closer to its closed seat and hunts between fully close and 8% open. This may cause large temperature swings on TC-238 which makes the burner fuel flow to cycle needlessly. If this starts to happen it is best to take manual control, (controller TC-245), and SLOWLY, over time, close the valve. The valve is fully closed during Heatup 4. Be careful to maintain TC-244 at >1000°F.

Four-hour hold/soak. At the end of Heatup 3 is a four-hour hold/soak. However the hold timer will reset, if the cathode in or out temperatures are not held within 20°F of the set point. The hold timer appears on the Mode Transition checklist as well as on the Fuel Cell graphic.

Heatup 4

During this part of the heatup (960-1110°F) the ramp rate of TC-238 returns to the 15°F/hr., since the electrolyte has completed its melt. When Heatup 4 is finished the anode inlet temperature at TI-331 should be >950°F, if it is not consult FCE Mgmt.

If the tertiary valve has not already closed in Heatup 3; it will be fully closed during this phase.

Hot Standby

The change from Heatup 4 to Hot Standby is only a name change—no plant parameters change. Hot standby was originally designed to reduce air flow to about 1000 scfm and prepare for power generation. But, if the air flow is lowered the anode inlet temperature cannot be maintained above 950°F.

Power Generation

Set FULL LOAD and REDUCED LOAD setpoints as needed for the planned load step.

Select POWER GENERATION MODE. The plant will ramp up at 2 kW/minute. Then monitor the fuel cell stack current indications very closely: delta As, cell voltages, cell temperature, and any plant systems that would effect the current such as, gas flow, temp control etc.…

Always use Full Load mode. In Full Load mode load increases and decreases are done at 2 kW/min. In Reduced Load mode increases are done at 2 kw/min. but decreases are done at 8 kW/min.

Grid Connect Mode. The net power target is increased by the auxiliary load to give the gross kW (AC) target. The DCS computer coverts the gross kW (AC) target to the gross kW (DC) by dividing by the power conversion system (PCS) efficiency (constant). The DCS computer coverts the gross kW (DC) demand to DC current demand using a look up table.

The DC current demand is used to set the PCS current set point and generates a demand fuel flow from the equation: (current demand x 0.00026 x cells per stack) / (Fuel Util x TH2). This value becomes the fuel flow set point.

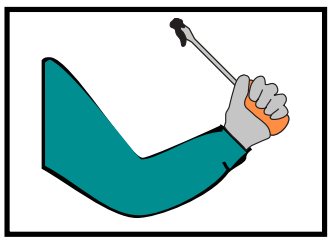
There are limits built into the circuit. Since water flow must always lead fuel flow, the fuel flow set point can be limited by the water flow during power increases to maintain the minimum steam-to-carbon ratio. Since power demand cannot exceed actual fuel flow, the PCS current set point can be limited by actual fuel flow. Since there is a maximum power setting, the Net AC power target cannot exceed this setting.

Main burner. While the main burner is on, the fuel cell cathode inlet temperature will be controlled by TC-238 increasing or decreasing FC-208 as needed. FC-210, total air flow, is in cascade and receives its set point from a look up table based on the current demand.

When the main burner is off, the fuel cell cathode inlet temperature will no longer be controlled by TC-238, control is provided by TC-243 which trims the total air flow set point. Total air flow is set from a look up table based on the current demand, however, its flow set point is also “trimmed” by TC-243 to maintain cathode inlet temperature (TI-238) at set point.

Anode gas oxidizer (AGO) response: As the fuel cell stack starts to load and generate power, it starts to use the gas delivered to it, causing the gas that was going to the AGO to decrease; until TC-238 can compensate by increasing the main burner fuel flow, the AGO will cooldown.

Reference



6.2 Operators Notes—Trip Recovery

When responding to a plant shutdown, you must find out why the plant tripped. This is usually the first alarm that tripped the plant, called the First Out, it is marked with a yellow arrow on the alarm screen. Before you acknowledge alarms or troubleshoot the fuel cell you need to document the trip, and what happened after the plant shut down. If the fuel cell temperature is below 500°F, then once the reason for the trip is corrected, a normal restart is used to reheat the fuel cell. If the fuel cell temperature is above 500°F a Rapid Restart can be used, either with anode cover gas or without depending on whether anode fuel was flowing to the fuel cell before the trip or not. The following module also gives you three case studies of plant trips.

When responding to a plant emergency shutdown (ESD):

Find out what alarm actually tripped the shutdown. Find out what alarm tripped the plant shutdown, figure out why a little later.

Find out whether the trip was completed sucesfully: After a trip has happened, verify all actions that should have happened, have taken place. Manually take action to complete any items that should have take place (shutdowns, valve closures etc.).

Print out ALL the alarms before you troubleshoot or acknowledge any alarms: Do not acknowledge/reset any alarms until you have decided what alarm actually caused the shutdown. Call up the Shutdown Trips Screen and print out ALL the alarm screens. Normally, this means printing several screens because, there will be several tabbed sheets, each tabbed sheet holds only 25 alarms, and the print function prints only the the tabbed sheet that is visible.

Decide how you will restart the plant. When you are ready to restart you will need to know which method to use: Normal restart, Rapid Restart w/Anode Cover Gas (ACG), or Rapid Restart w/o ACG.

The ultimate decision will be made by Team Lead in consultation with Fuel Cell Management, but here are the general rules:

NOTE: The median of TI 320 is used as the fuel cell temperature. This is the median of temperatures at TI 320A/B/C.

- Fuel cell temperature less than 150°F, startup with the electric heater/blower
- Fuel cell temp greater than 150°F but less than 500°F, do normal trip restart
- Fuel cell temp greater than 500°F but less than 700°F, Rapid Restart with out anode cover gas
- Fuel cell temp greater than 700°F, Rapid Restart w/ anode cover gas

Rapid Restart

Select Rapid Restart from the Hot Restart checklist and, after consulting with Fuel Cell Mgmt, when prompted for Fuel Cell Best Temperature enter the value they give you.

The Hot Restart logic sets the ramp end point to a representative fuel cell temperature, increases the TY-238 ramp rate to 600°F/hr. and places the plant in AUTO STARTUP.

If ANODE COVER GAS is selected (fuel was flowing before to the trip), the operator will be dispatched to put one bottle in service.

ACG outlet isolation valve XV-290 opens. When the anode pressure is greater than cathode pressure by 1 inch W.C. (PDI-257), for one minute, the air blower will be allowed to start.

Plant enters Heat up 2. The plant enters Heat Up 2 and the air blower starts to purge the anode gas oxidizer (AGO). During the purge, the total air flow controller (FC-210) will be in auto with a set point of 900 scfm. The purge will last 2 minutes. When the purge is finished the pilot will light.

Unlike a “normal” startup, the main burner will light off as soon as the pilot flame is sensed by the fire-eye. At this low air flow rate, the temperature will increase rapidly in the AGO, which is what we want. When the cathode inlet temperature reaches the “Best Temperature” –150°, the total airflow controller will change its set point to 3,500

scfm and will ramp up to this flow rate at 2.2 scfm/sec.

If using Rapid Restart with anode cover gas, the total air flow will be held at 2,000 scfm until the fuel and water are enabled.

NOTE: The catalyst heat up ramp, and the TC-238 ramp hold at 700°F are disabled during Rapid Restart.

Gas and water will start when all normal conditions are met: (preconverter temperature (TI-142) >600°F, HRU outlet temperature (TI-125) >500°F and catalyst out temperature (TC-244) >1,000°F). If cover gas was in service, it will now be isolated.

In Rapid Restart, once the Heat Up 3 ramp up is finished, the 4 hour hold/soak is bypassed. Fuel cell bypass valve (HV-240), will be open until the Rapid Restart is complete. During the TY-238B ramp, the feed forward (FF) input to TC-238 will be automatically disabled if: TC-246 ≥ TC-238 SP +30°F, and enabled if: TC-246 < TC-238 SP +30°F.

Rapid Restart ends when:

- Both Fire Eyes see the flame
- TC-238 >BEST Temp
- FC-210 >3,400 scfm

Once Rapid Restart ends:

- The catalyst temperature ramp will come out of hold, and it will return TC-244 to 1010°F at 250°F/hr., if needed. At 1010°F, TC-244 will return to the normal setting.
- TY-244C will go through a Track-On/Track-Off cycle to ensure a large deviation between PV and set point will not make the tertiary valve to open too rapidly.

Three ways the plant can respond

When using Rapid Restart, how the plant responds depends on what the fuel cell plant conditions were before it tripped. Although most of the plant control is done automatically, the operator needs to understand how the plant responds to: minimize the fuel cell temperature fluctuations, minimize the time needed to return the AGO to the fuel cell temperature, and minimize the time needed before gas and water are re-enabled.

The following table describes the 3 cases:

Case	Fuel Cell Temps	Plant temps before trip	TC-238 Response	Notes
1	1000–1,200°F	TC-238 > TC-244	Heatup to the best fuel cell temperature	Feed forward (FF) to TC-238 will help return temperature. Gas and water reenable quickly.
2	700 – 1,000°F	TC-238 < TC-244	Cooldown slightly to best fuel cell temperature	FF to TC-238 will sometimes fight efforts to cooldown. Gas and water take longer to reenable.
3	500 – 700°F	TC-238 about equal to TC-244	Cooldown slightly to best fuel cell temperature	FF to TC-238 will sometimes fight temperature control. Gas and water will not be reenabled.

Case 1, a high temperature trip. TC-238 will overshoot its ramp end point (BEST TEMP –50°F), so when TC-238 PV exceeds TC-238 ramp end point, the end point will automatically be reset to BEST TEMP.

Gas and water will be enabled very soon after starting Rapid Restart because the catalyst temperature normally does not go below 1000°F.

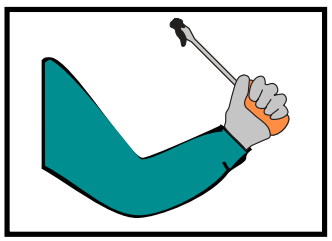
Case 2, a medium temperature trip. In this case, the TC-238 temperature will actually increase during the purge because purge air will be warmed by the catalyst which was at a higher temperature than TC-238 and the fuel cell. Therefore, TC-238 will act to cooldown, instead of heat up the system.

Early in the restart TC-238 PV will normally exceed the TY-238B ramp end point. Logic will automatically reset the end point to the fuel cell BEST TEMP. In this case, if feed forward (FF) was always enabled it would fight the effort to cooldown. So the operator must verify that FF actually enables when TC-246 < TC-238 SP+30°F, and disables when TC-246 ≥ TC-238 SP +30°F.

After the Rapid Restart ends, the catalyst heat up ramp rate will start at a 250°F/hr. The operator will also need to verify that TC-245 has cycled through Track-On and then Track-Off to prevent the tertiary valve from opening too fast and causing small temperature fluctuations at TC-238.

Case 3, a low temperature trip. TC-238 will be recovering to a Best Temp less than 700°F, so when Rapid Restart finishes, the operator will need to discuss the situation with FCE Management and then on their recommendation start a catalyst heatup. When less than 700°F, the plant does not automatically start a rapid heat up of the catalyst.

Reference



6.3 Operators Notes— the Anode Cover Gas System and Nitrogen Purge

During a hot restart, if the plant trips, oxygen can diffuse into the anode, oxidizing the catalyst. This happens when the fuel cell is "hot" (over 700°F) and air is flowing over the cathode but there is no fuel flow in the anode. In order to relight the anode gas oxidizer (AGO), it must be purged, relit, and heated. The AGO air blower must operate during this time. Although there is a bypass line around the cathode, the cathode cannot be fully isolated. Anode cover gas (from cylinders) is used to protect the catalyst from the air flow from the blower.

To prevent air from leaking from the cathode into the anode before fuel flow is started, the anode must be blanketed with a reducing gas at an anode pressure of 1 inch W.C. above the cathode pressure. This is called anode cover gas.

Anode cover gas

Gas composition and flow rate . Cylinders of cover gas contain nitrogen (N2) with 3±0.5 percent hydrogen; it is mixed with 0.1 scfm of pure nitrogen from the anode slow purge system.

Anode cover gas system. Two 200 cu.ft. cover gas cylinders are connected to the cover gas header using flexible hose. Each cylinder can be isolated using manual valves HV-290 and HV-291. When not in use, both bottles are isolated at the bottle until needed to reduce the chance of a small leak draining one or both bottles.

One bottle is used at a time. The cylinders are mounted on a rack near the gas analyzer calibration gas cylinders. Pressure transmitter PT-290 monitors the supply pressure in the cylinders. Cover gas is filtered in FL-290 and then passed through regulator PCV 290, which is set at 40 psig. Pressure gauges PI-291 and PI-292 monitor the upstream and downstream pressure of the regulator. Relief valve PSV-290, set at 50 psig, protects the anode cover gas distribution header. Anode cover gas is supplied by opening on/off valve XV-290. Gas flow rate is controlled by needle valve HV -293. Check valve CHV-290 prevents the entry of any fuel gas into the anode cover gas system. The anode cover gas is tied into the 3-inch mixing tee at the anode inlet.

Cover gas control. The flow rate of anode cover gas is controlled by throttling needle valve HV-293. Anode cover gas is needed during the rapid restart process or trip recovery, whenever fuel gas had been flowing before the trip.

The logic closes the anode inlet and outlet block and vents (XV-247A, XV-247B, XV-260 and XV-262) and opens anode N2 bleed valve (XV-280).

It prevents the AGO blower from starting until a 1 inch W.C. differential pressure (DPI-257) exists between the cathode in (PT-309) and the anode out (PT-252), for 60 seconds.

The DCS then opens cover gas isolation solenoid valve (XV-290) and introduces the cover gas into the anode.

Once the anode and cathode differential pressure have been confirmed and the 60-second timer times out, the AGO blower is started.

The AGO system heats up the fuel cell to the fuel enable set point. Then the fuel block valves (XV-247A and XV-262) are opened, and fuel and water are enabled using FV-117 and FV-131. After a 10 second delay, the cover gas isolation valve (XV-290) closes.

The DCS monitors the cover gas supply pressure (PT-290). A low pressure set point indicates that a cylinder needs replacing. DCS interlock prevents the plant from starting a plant heatup if the cover gas pressure is below the low-low set point.

Nitrogen purge systems

The two nitrogen purge systems, each have their own nitrogen supply and instrumentation.

The fast purge system can produce 100 scfm total: 50 scfm to the fuel treatment system through valve XV-191, and 50 scfm to the anode of the fuel cell though valve XV-280. Both are vented to atmosphere.

The slow purge system, also called the slow bleed system, can produce 0.6 scfm total: 0.5 scfm to the cathode in through valve XV-284, and 0.1 scfm to the anode through valve XV-284. Both are vented to the atmosphere.

Normal shutdown. As system temperatures (TI-320A, TI-142 or TC-120) drop below set point during a "normal cooldown," (when the system cooling is based on cooling cathode gas flows), valve XV 191 automatically opens to purge the fuel system piping. The section from FV-117 to the AEG inlet is purged. Mainline block isolation valves and vent valves are kept in their normal operating positions. The nitrogen is consumed in the anode gas oxidizer (AGO).

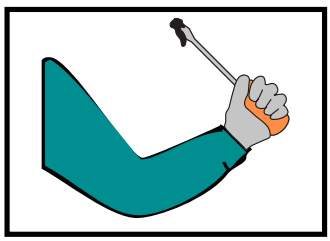
Emergency shutdown. When cooldown comes from an emergency trip, the process fuel and water flow valves close, the anode outlet block valve (XV-262) stays open for 10 minutes then closes when the anode inlet and outlet vent valves close (XV-247B and XV-260). The slow purge system purges the anode and cathode (using XV-280 and XV-284); this limit the amount of air pulled into the plant as it cools.

When the fuel cell temperature drops below 650°F or if the slow purge cylinders are empty, a N2 low pressure alarm (PAL-190) registers and a fast purge starts (using XV-282 and XV-191). Valve XV-260 and XV-247B should be opened and XV-247A closed. This allows the operator time to correct the fault that caused the emergency trip, and to try to bring the plant back online using a Rapid Restart, but still purges the fuel system with nitrogen if the Rapid Restart cannot be started.

NOTE: When anode cover gas is started, the anode bleed valve (XV-280) is opened.

The anode fast purge valve (XV-282) will not open if valve XV-260 is not open and valve XV-262 is not closed.

Reference



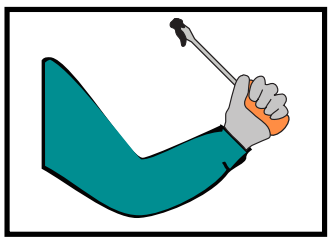
6.4 Operators Notes—Monitoring Cell Group Voltage Deviation

Voltage deviation is the most important indicator of fuel cell health, because when fuel cells are put on load, or as more load is demanded from the stacks, the voltage decreases. While the voltage decrease is normal, all the fuel cell groups should respond equally. The best way to measure this is to compare each cell group average voltage against the entire stack average voltage; the difference is called the cell group voltage deviation or dV/cell.

How monitor a dV/cell

Proprietary information—
Not Available for Publication.

Reference



6.5 KCPP Startup to Hot Standby (NG)

Use this procedure when the plant is shutdown and is at ambient temperature. The plant target mode and actual plant mode is EMERGENCY SHUTDOWN. This would be a startup from a fairly normal shutdown. Always find out why the plant tripped, and document all alarms and equipment status by printing out the required screens, before assessing and restarting the plant. This procedure uses scrubbed methane for both anode fuel and the oxidant burner.

Assessing the plant system

Before changing plant operating modes do the following operations if needed.

1. **Do initial valve line-ups as needed.**
   "Initial Valve Lineup Checklist" on page 6-104

2. **Verify utility systems are started and available using applicable procedures.**
   a) Electrical—Un-isolate the inverters and DC interface. "Operating the EBOP" on page 6-88
   b) Water Treatment "Operating the Water Treatment System" on page 6-84
   c) Nitrogen (If XV-191, XV-280, XV-282 and XV-284 are open, then placing the nitrogen bottles on service may need to be delayed until plant is in IDLE Mode.) Nitrogen should remain isolated until gas/water are enabled. "Operating the Nitrogen System" on page 6-78
   d) Instrument Air "Starting the instrument air system" on page 6-95
   e) Safety and Fire Protection "Operating the fire alarm panel" on page 6-94
   f) Ventilation for Fuel Prep and Water Treatment Skids. "Operating the ventilation systems" on page 6-94
   g) Anode Cover Gas. "Operating the Nitrogen System" on page 6-78

3. **Verify instrument and control circuits are energized.**

4. **Verify the local hand switches for the startup skid blower, start up heater, and AGO are in off position.**

5. **Verify the following disconnects are closed (ON).**
   - Cathode air blower disconnect is closed, DIS-200 (in front of the of air blower panel),
   - The breaker inside air blower panel for XFT-100 is closed (15 amp breaker).
   - The drive disconnect on VFD is on, (inside air blower panel).

6. **Check that the startup (S/U) heater/blower skid has power.**
   a) Verify that power and instrumentation cables are properly connected. Plug in the cables if needed.
   b) Turn on power to the startup skid receptacle (Breaker CB-155D in EBOP) and turn on the Startup Skid receptacle (Welding receptacle on the corner of the Fuel Prep skid, near the Preconverter after filter).
   c) Close the panel breaker for the startup heater and blower on the local control panel.

7. **Check that no equipment has been left disassembled, and all electrical and control systems are restored if maintenance has been done.**
   Check and adjust the valve lineup, if needed. See "Initial Valve Lineup Checklist" on page 6-104.

8. **Check that all lockout tagouts have been removed and the retest of affected equipment is finished, if possible.**

9. **If needed, start up the fuel preparation system and purge with methane.**
   "Operating the Fuel Preparation System" on page 6-62.

CAUTION

Unless the plant is in Idle, an emergency shutdown (ESD) will happen when the purge is finished and XV-103A and XV-103B close. Be careful because an EDS will change many valves positions. These will need to be readjusted.

In order to open XV-103A and XV-103B proceed as follows:

a) If a shutdown condition exists, go to alarm summary screen and acknowledge/clear all existing alarms.

b) Go the Shutdown (S/D) Trip screen and verify all S/D Trips are green. The HS-111A software switch may still be red at this time. If any other trips exist investigate, troubleshoot, and clear the condition trip before proceeding.

c) Reset the HS-111A software switch.

d) Open XV-103A and XV-103B and purge the natural gas system with natural gas. See "" on page 6-62.

e) Close XV-103A and XV-103B.

NOTE: Unless the plant is in Idle, closing XV-103A and XV-103B will cause a plant ESD.

10. **On the King Count Operation Mode Control screen verify the PLANT STARTUP OPTION for AUTO STARTUP is set to MANUAL.**

11. **On the King County Plant Settings screen verify all settings using the PLANT SETTINGS table.**
    See "Startup to Hot Standby plant settings" on page 6-22.

Changing from SHUTDOWN to IDLE

CAUTION

Do not transition to IDLE unless you are prepared to restart the plant. Shutdown is a stable state.

1. **If a RAPID RESTART was in progress and not finished, verify Rapid Restart has been aborted.**
   Go to the OPMODE screen. If a red ABORT RAPID RESTART is displayed, the Rapid Restart has been aborted. If RAPID RESTART IS ACTIVE is displayed, abort the Rapid Restart by selecting the ABORT button on the OPMode screen.

2. **If shutdown conditions still exist, go to the alarm summary screen and acknowledge/clear all existing alarms.**

3. **On the S/D Trip screen and verify all S/D Trips are green. The HS-111A Software Switch may still be red at this time.**
   If any other trips exist, investigate and clear the condition that caused the trip before proceeding.

4. **On the S/D Trip screen, push the 1st OUT RESET button to reset the first out pointer, and then press the FAIL MESSAGE RESET, if needed.**

5. **Reset the HS-111A software switch.**

6. **At the electrical balance of plant (EBOP) enclosure, press the SHUTDOWN RESET button (green HS-112).**

7. **On the King Count Operation Mode Control screen, select IDLE.**
   The box for IDLE will turn yellow, and the mode transition checklist will appear for IDLE MODE.

8. **Verify that the Plant Target Mode is IDLE and the Actual Plant Mode is EMERGENCY SHUTDOWN.**

9. **Verify IDLE mode transition checklist items are complete.**
   If text is blue with a red X, the operator must verify the step is complete and then click on

the blue text to change the red X to a green check mark.

If a red X is next to black text, when the DCS gets a signal that this step is complete it will change the red X to a green check mark. DCS may not automatically do this step so the operator may need to click on the black text to do this step.

10. **On the burner management system (BMS) panel, verify the EMERGENCY STOP (PB-62A/HS-231B) is pulled out, and then push the ACKNOWLEDGE (PB-246), RESET (PB-245), and ESD RESET (PB-62B) push buttons.**

11. **On the DCS, verify that the AGO SHUTDOWN button (HS-231A) does not have a shutdown signal. Reset the AGO shutdown if needed**.
    Open the AGO SHUTDOWN button and if HS-231A is green it needs to be reset. If HS-231A is red no shutdown signal is being sent to the AGO.

12. **Verify the DCS did the following pre-mode shift actions for IDLE MODE:**
    - HV-240 is closed.
    - XV-103A and XV-103B are closed to isolate natural gas to unit.
    - XV-820A and XV-820B are closed to isolate digester gas supply.
    - XV-191, XV-280, XV-282 and XV-284 closed to isolate purge and bleed nitrogen.
    - XV-247B and XV-260 closed and XV-247A and XV-262 open.
    - Cathode air blower (HS-224) is off with XV-241A closed.
    - Preconverter heater control (XS-195) is off.
    - Digester gas compressor (HS-800A) is off.
    - TC-120 is in manual with an output of –5.
    - On the water treatment system push WTS ALARM RESET button to reset the UA-406 alarm and verify a Water Treatment System Permitted (HY-404) is displayed.
    - Verify PCS OP MODE Target is GRID.
    - Verify XV-290 is closed.

13. **Verify the plant is now in IDLE mode.**
    When in IDLE mode, the box for IDLE will turn green.

14. **If needed, change out nitrogen six-packs and put the nitrogen bottles in service now.**
    "Operating the Nitrogen System" on page 6-78

15. **Check each of the anode cover gas bottle pressures (2) are greater than 1500 psig. Change out bottles that are less than1500 psig.**

Changing from IDLE to HEATUP-1

The startup skid is used to heat up the fuel cell stack. The ambient temperature is brought to 150°F on TI-240 at a ramp up rate of 15°F/hr. with an end point of 300°F. Once the AGO system is ready the startup skid equipment is shutdown and the next heatup cycle begins. The startup skid heater and blower can be used to hold the fuel cell stack temperature above the minimum 150°F temperature while the AGO system is prepared for startup.

1. **Start up the startup skid.**
   See "Starting up the startup skid" on page 6-60.

2. **On the King Count Operation Mode Control screen select HEATUP-1.**
   The box for HEATUP-1 will turn yellow, and the mode transition checklist will appear for HEATUP-1 MODE.

3. **Start the startup blower.**
   On the local control panel, turn the motor switch to ON.

4. **Verify that the Plant Target Mode is HEATUP-1 and the Actual Plant Mode is IDLE.**

5. **Verify HEATUP-1 mode transition checklist items are complete.**
   If text is blue with a red X, the operator must verify the step is complete and then click on the blue text to change the red X to a green check mark.

   If a red X is next to black text, when the DCS gets a signal that this step is complete it will

change the red X to a green check mark. DCS may not automatically do this step so the operator may need to click on the black text to do this step.

6. **Verify DCS did the following pre-mode shift actions:**
   a) HV-240 opens 100% (HIC-240 output 100%).
   b) All other valves and controls will be in the same state used for Idle. (If any of the valves are not in position for Idle, as the valve position changes for Heat Up 1, an ESD may occur).
7. **Verify the plant is now in HEATUP-1 mode.**
   The box for HEATUP-1 will turn green when in the HEATUP-1 mode. Once the change to Heat Up 1 is complete verify TY-216B begins to ramp at 15°F/hr. with an end point of 300°F.
8. **Close HV-240 when TI-216 is greater than TI-240.**
9. **Turn on power to the preconverter heater control panel at the control panel.**
10. **Start the preconverter jacket heater from DCS (XS-195).**
    Once the heater is enabled, the heater is set for 900 °F internal temperature and the jacket heater is set to 1,050 °F; the over temperature shutoff is set at 1,100 °F on the control panel.
11. **Verify TDI-218 remains less than 100°F.**
    If TDI-218 gets to 100 °F, the TY-216B ramp is held until temperature differential is reduced.
12. **Verify HEATUP-1 is complete.**
    When HEATUP-1 is complete (TI-240 is >225°F) an alarm registers on the DCS.

    Verify the HEATUP-1 Mode Complete Actions on the HEATUP 1 Mode table.

CAUTION

TI -240 should not be allowed to go above 300°F because this could damage the startup blower. The heater rampup will continue to 300°F, unless the operator shuts off the heater. Leaving the heater on increases the time available to change from the startup heater heater and blower to the AGO burner and blower, without the stack temperature dropping below the minumum 150°F metal temperature.

Changing from HEATUP-1 or HOT RESTART to HEATUP-2(NG)

Cathode temperature is >150 °F on TI-240. HEATUP-2 NG, minimum is set to 880 °F on TC-238 with a ramp up rate of 15 °F/hr.

1. **When the desired temperature is reached, disable the startup heater ramp (TY-216B).**
   a) Turn the startup blower switch HS-220 to OFF.
   b) Isolate the startup heater by closing valves MV 2039 and MV 2040, and opening valve MV 2042 (startup heater drain valve).
2. **Once the AGO system is running, continue to turn off and isolate the startup heater and blower.**
   "Shutting down the startup skid" on page 6-60.

CAUTION

Do not allow anode cover gas flow for longer than 30 minutes without having the AGO air blower running. Because the atmosphere created by the cover gas could damage the fuel cell stack module if left in place.

3. **Verify AGO air blower interlocks are satisfied:**
   a) There are no remote plant ESD (all the hand switches on S/D Trips Screen are green).

b) Check for a BMS ESD trip by doing the following:
   - Verify the EMERGENCY STOP (PB-62A/HS-231B) on BMS panel (locally at the AGO) is pulled out.
   - Verify on the DCS that the AGO SHUTDOWN button (HS-231A) does not have a shutdown signal (Open the AGO SHUTDOWN button on the AGO screen. If HS-231A is green it needs to be reset. If HS-231A is red no shutdown signal is being sent to the AGO).
   - Then locally at the AGO on the BMS panel, push the ACKNOWLEDGE (PB-246), RESET (PB-245), and ESD RESET (PB-62B) push buttons.

c) There is no high vibration condition alarm (VAH-224) registering.

NOTE: Shortly after selecting HEATUP-2 NG the AGO blower will start. Monitor for proper blower startup at the DCS and locally.

4. **Verify XV-241 is closed before selecting HEATUP-2 NG.**
   If it is opened before HEATUP-2 is selected, the change in the heatup status may cause a plant trip.

5. **As soon as possible after selecting HEATUP-2, verify the DCS did the following:**
   a) Opened HV-240 (HIC-240 at 100%)
   b) Opened XV-103A and XV-103B (anode natural gas supply)
   c) Set temperature controller TC-120 in AUTO at 775 °F
   d) Turned XS-195 preconverter jacket heater on.

6. **On the King Count Operation Mode Control screen, select HEATUP-2 NG.**
   The box for HEATUP-2 NG will turn yellow and the mode transition checklist will appear for HEATUP-2 NG MODE

7. **Verify that the Plant Target Mode is HEATUP-2 NG and the Actual Plant Mode is HEATUP-1 (or HOT RESTART if doing a hot restart).**

8. **Verify the AGO blower outlet valve XV-241A opens, the blower starts and that the discharge pressure increases to about 28 inches W.C. (PC-222).**
   The blower will ramp to a total air flow of 900 scfm (FC-210) at a 28 inches W.C. discharge pressure.

9. **Verify HEATUP-2 NG mode transition checklist items are complete as needed.**
   If text is blue with a red X, the operator must verify the step is complete and then click on the blue text to change the red X to a green check mark.

   If a red X is next to black text, when the DCS gets a signal that this step is complete it will change the red X to a green check mark. DCS may not automatically do this step so the operator may need to do this step.

10. **Once PDAL-233 resets (primary air flow pressure switch across FC-230), on BMS panel, start the AGO pilot as follows:**
    a) Press the SYSTEM STOP/RESET push-button.
    b) Verify the LIMITS SATISFIED light is on.
    c) Press SYSTEM LOCAL START push-button.
    d) Check that the following happened (locally and on DCS):
       - Purge light is on (local only).
       - Purge lasted for 2 minutes.
       - After the purge finishes, the pilot gas valves XV-203 and XV-205 and pilot air valve XV-260 should open.
       - Within 10 seconds the pilot should light, indicated by the UV flame scanner (BE-233) light coming on.

11. **Once the pilot is lit, verify that FC-210 resets to 3,500 scfm and is in AUTO.**

12. **Verify HV-240 closes as TC-238 becomes greater than TI-240.**

13. **When FC-210 exceeds 2,000 scfm verify:**
    a) XV-212 and XV-214 are open.
    b) The main burner is lit.

NOTE: If the plant has been shutdown for a long time, then BE-243 may not immediately indicated a flame. As long as either the main burner or pilot is on, BE-233 will show a flame.

c) XV-203 and XV-205 are closed.

14. Verify the plant is now in HEATUP-2 NG mode.

The box for HEATUP-2 NG will turn green when it is in the HEATUP-2 NG mode.

15. Monitor plant parameters for abnormalities and be sure the ramps happen as follows:

a) TY-238B will begin to ramp at 15 °F/hr. until TC-238 reaches 885 °F; TC-238 (cathode inlet temperature) and FC-208 (fuel gas to AGO burner) will change to CAS.

b) TY-238B ramp will hold if TC-238 reaches 700 °F and the preconverter catalyst bed temperature (TI-142) is <600 °F or the oxidizer catalyst bed temperature is <1000 °F.

c) As the oxidizer outlet temperature, TC-238 rises above 500 °F, TY-244C will enable and TC-245 will raise the catalyst temperature to >1000 °F at 30 °F/hr. Then TC-245 will change to CASCADE and control the tertiary air valve TV-245 and maintain the ramp set point.

d) Once catalyst outlet temp, TC-244, reaches 1,000 °F, TY-244C will maintain catalyst temperature at >1,000 °F (the TY-244C end value will be 1,010 °F).

16. Start the anode and fuel gas line heat traces.

Close breakers CB-161F and CB-163A. Check that breakers 163B, 163C, 163D, 163E, 163F, and 163G are closed.

17. Verify that the natural gas and water treatment systems are lined-up, and operating and ready to supply water. Verify water valve MV-4042 and gas valve MV-1063 are open, before the following five things happen:

- Preconverter catalyst bed temperature (TI-142) is >600 °F.
- Oxidizer catalyst bed temperature is at or >1,000 °F on TC-244, which is the average of TI-244A/B/C temperatures.
- HRU stack exhaust temperature (TI-125) is >500 °F.
- Anode inlet low low temperature alarm (TALL 331) is above 300°F.
- Anode outlet valve XV 262 opens.

18. Once the above five-conditions are met, verify anode fuel flow is established.

Water should begin to flow using FC-131, and fuel should begin to flow using FC-117 (minimum valve based on plant settings page) to maintain a steam-to-carbon ratio of 8:1. FC-131 and FC-117 should be in cascade.

19. When HEATUP-2 (TC-238 at 885°F) is finished, a Sequence Alarm is actuated in DCS and plant will hold at the TY-238B ramp end value.

Changing from HEATUP-2 NG to HEATUP-3 NG

The cathode temperature is >880 °F on TI-238. To change to HEATUP-3 NG (880 °F to 960 °F on TC-238) the system will use a ramp up rate of 12°F/hr.

1. Verify the ramp rate in the Plant Settings table, check the heatup (HU)/cooldown (CD) temperature ramp rates for HU3 and CD2 is 12 (deg F/hr.).

2. On the King Count Operation Mode Control screen, select HEATUP-3 NG.

The box for HEATUP-3 NG will turn yellow and the mode transition checklist will appear for HEATUP-3 NG mode.

3. Verify the plant target mode is HEATUP-3 NG and the actual plant mode is HEATUP-2 NG.

4. Verify HEATUP-3 NG mode transition checklist items are complete.

If text is blue with a red X, the operator must verify the step is complete and then click on the blue text to change the red X to a green check mark.

If a red X is next to black text, when the DCS gets a signal that this step is complete it will change the red X to a green check mark. DCS

may not automatically do this step so the operator may need to do this step.

5. **Verify the plant is now in HEATUP-3 NG mode.**
   The box for HEATUP-3 NG will turn green when in the HEATUP-3 NG mode.

6. **Verify in DCS that TY-244C is in RAMP ENABLED, RAMP NOT PAUSE, TRACK OFF with end value of 1010°F and TY-238B is in RAMP ENABLED, RAMP NOT PAUSE, TRACK OFF with an end value of 990°F.**
   Change the track on/off as necessary.

7. **Verify the DCS did d the following mode shift actions for Heatup-3 NG:**
   a) XS-195 (preconverter jacket heater) is on.
   b) TC-238 will remain in cascade.
   c) TC-243 will remain in manual with a set point of 1.0.
   d) FC-117 will remain in cascade.
   e) FC-131 will remain in cascade.
   f) FC-208 will remain in cascade.
   g) FC-210 will remain in auto with a set point of 3500 scfm.
   h) FC-230 will remain in cascade.
   i) TC-245 will remain in cascade.
   j) TC-244 will remain auto.
   k) TC-120 will remain in auto with a set point of 775 °F.

8. **Using TC-238, monitor the heat up to verify it is actually ramping up at 12°F/hr.**

9. **Verify that temperature holds for 4 hours at 990°F (the end point of Heat up 3).**
   This heat soak will make sure that at the end of electrolyte melt the temperatures throughout the stack are even.

10. **When HEATUP-3 is complete an alarm is actuated in DCS.**

Changing from HEATUP-3 NG to HEATUP-4 NG

Cathode temperature is >990 °F on TC-238 and TI-240. HEATUP-4 NG will raise the temperature from 985 °F to 1,105 °F on TC-238, with a ramp up rate of 15 °F/hr.

1. **On the King Count Operation Mode Control screen, select HEATUP-4 NG.**
   The box for HEATUP-4 NG will turn yellow and the mode transition checklist will appear for HEATUP-4 NG mode.

2. **Verify the plant target mode is HEATUP-4 NG and the actual plant mode is HEATUP-4 NG.**

3. **Verify the HEATUP-4 NG mode transition checklist items are complete.**
   If text is blue with a red X, the operator must verify the step is complete and then click on the blue text to change the red X to a green check mark.

   If a red X is next to black text, when the DCS gets a signal that this step is complete it will change the red X to a green check mark. DCS may not automatically do this step so the operator may need to do this step.

4. **Verify the plant is now in HEATUP-4 NG mode.**
   The box for HEATUP-4 NG will turn green when in the HEATUP-4 NG mode.

5. **Verify in DCS that TY-244C is in RAMP ENABLED, RAMP NOT PAUSE, TRACK OFF; and TY-238B is in RAMP ENABLED, RAMP NOT PAUSE, TRACK OFF with an end value of 1110, and a ramp rate of 15°F/hour.**
   Change the track on/off as necessary.

6. **Verify the DCS did the following mode shift actions for HEATUP-4 NG.**
   a) XS-195 (preconverter jacket heater) is on.
   b) TC-238 will remain in cascade.
   c) TC-243 will remain in manual with a set point of 1.0.
   d) FC-117 will remain in cascade.
   e) FC-131 will remain in cascade.
   f) FC-208 will remain in cascade.
   g) FC-210 will remain in auto with a set point of 3500 scfm.
   h) FC-230 will remain in cascade.
   i) TC-245 will change to auto with set point 500.
   j) TC-244 will remain in auto.

k) TC-120 will remain in auto with a set point of 875°F.

7. **Using TC-238, monitor ramp up to verify it is actually ramping up at 15°F/hr.**

8. **When HEATUP-4 is finished (1,105 °F) an a alarm registers on the DCS.**

Changing from HEATUP-4 NG to HOT STANDBY NG

Heatup 4 is the ramp up from 985°F to 1,105°F. The cathode temperature is >1,050 °F on TC-240. The change to Hot Standby is when conditions are steady and TC-238 is about 1,110°F. The end of HEATUP-4 NG is essentially the same as HOT STANDBY NG.

1. **On the King Count Operation Mode Control screen verify that "EXTENDED HOTSTANDBY" is NO.**

2. **On the King Count Operation Mode Control screen select HOT STANDBY NG.**
   The box for HOT STANDBY NG will turn yellow and the HOT STANDBY NG mode transition checklist will appear.

3. **The plant target mode is HOT STANDBY NG and the actual plant mode is HEATUP-4 NG.**

4. **Verify HOT STANDBY NG mode transition checklist items are complete.**
   All blue and black text are followed by a green check mark.

   If text is blue with a red X, the operator must verify the step is complete and then click on the blue text to change the red X to a green check mark.

   If a red X is next to black text, when the DCS gets a signal that this step is complete it will change the red X to a green check mark. DCS may not automatically do this step so the operator may need to do this step.

5. **Verify the DCS did the following mode shift actions for Hot Standby.**

   a) XS-195 (preconverter jacket heater) is OFF. (May be turned on if needed to maintain the catalyst temperature).

   b) TC-238 will change to auto with a set point of 1,110.

   c) TC-243 will remain in manual with a set point of 1.0.

   d) FC-117 will remain in cascade.

   e) FC-131 will remain in cascade.

   f) FC-208 will remain in cascade.

   g) FC-210 will remain in auto with a set point of 3,500 scfm.

   h) FC-230 will remain in cascade.

   i) TC-245 will remain in auto with a set point of 500.

   j) TC-244 will remain in auto.

   k) TC-120 will remain in auto with a set point of 775 °F.

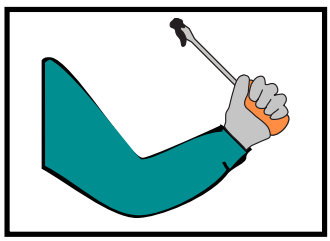
6. **At completion of HOT STANDBY sequence a DCS alarm is actuated.**

7. **Maintain HOT STANDBY until plant is placed on load (producing power) or plant needs to be changed to cooldown mode, or extended Hot Standby.**

Startup to Hot Standby plant settings

Proprietary information— Not Available for Publication.	

Reference



6.6 Startup to Hot Standby DG

Use this procedure when the plant is shutdown and is at ambient temperature. The plant target mode and actual plant mode is EMERGENCY SHUTDOWN. This would be a startup from a fairly normal shutdown. Always find out why the plant tripped, and document all alarms and equipment status by printing out the required screens, before assessing the and restarting the plant. This procedure uses scrubbed methane for the oxidant burner and conditioned raw sludge gas for anode fuel makeup. The initial assessment of the fuel cell plant, and the transitions from SHUTDOWN to IDLE, and IDLE to HEATUP-1 are the same as when using scrubbed methane for anode fuel. The digester gas preparation system must be started and valved in to run in digester gas mode, and fuel control valve FC-800 is used instead of FC-117.

Assessing the plant system

Before changing plant operating modes do the following operations if needed.

1. **Do initial valve line-ups as needed.**
   "Initial Valve Lineup Checklist" on page 6-104

2. **Verify utility systems are started and available using applicable procedures.**
   a) Electrical—Un-isolate the inverters and DC interface. "Operating the EBOP" on page 6-88
   b) Water Treatment "Operating the Water Treatment System" on page 6-84
   c) Nitrogen (If XV-191, XV-280, XV-282, and XV-284 are open, then replacing the nitrogen bottles on service may need to be delayed until plant is in IDLE Mode.) Nitrogen should remain isolated until gas/water are enabled. "Operating the Nitrogen System" on page 6-78
   d) Instrument Air "Starting the instrument air system" on page 6-95
   e) Safety and Fire Protection "Operating the fire alarm panel" on page 6-94
   f) Ventilation for Fuel Prep and Water Treatment Skids. "Operating the ventilation systems" on page 6-94
   g) Anode Cover Gas. "Operating the Nitrogen System" on page 6-78

3. **Verify instrument and control circuits are energized.**

4. **Verify the local hand switches for the startup skid blower, start up heater, and AGO are in off position.**

5. **Verify the following disconnects are closed (ON).**
   - Cathode air blower disconnect is closed, DIS-200 (in front of the of air blower panel),
   - The breaker inside air blower panel for XFT-100 is closed (15 amp breaker).
   - The drive disconnect on VFD is on, (inside air blower panel).

6. **Check that the startup (S/U) heater/blower skid has power.**
   a) Verify that power and instrumentation cables are properly connected. Plug in the cables if needed.
   b) Turn on power to the startup skid receptacle (Breaker CB-155D in EBOP) and turn on the Startup Skid receptacle (Welding receptacle on the corner of the Fuel Prep skid, near the Preconverter after filter).
   c) Close the panel breaker for the startup heater and blower on the local control panel.

7. **Check that no equipment has been left disassembled, and all electrical and control systems are restored if maintenance has been done.**
   Check and adjust the valve lineup, if needed.

8. **Check that all lockout tagouts have been removed and the retest of affected equipment is finished, if possible.**
   See "KCPP Shutdown Procedure" on page 6-54.

9. **If needed, start up the fuel preparation system and purge with methane.**
   "Operating the Fuel Preparation System" on page 6-62.

CAUTION

Unless the plant is in Idle, an emergency shutdown (ESD) will happen when the purge is finished and XV-103A and XV-103B close. Be careful because an EDS will change many valves positions. These will need to be readjusted.

In order to open XV-103A and 103B proceed as follows:

a) If a shutdown condition exists, go to alarm summary screen and acknowledge/clear all existing alarms.

b) Go the Shutdown (S/D) Trip screen and verify all S/D Trips are green. The HS-111A software switch may still be red at this time. If any other trips exist investigate, troubleshoot, and clear the condition trip before proceeding.

c) Reset the HS-111A software switch.

d) Open XV-103A and XV-103B and purge the natural gas system with natural gas. See "" on page 6-62.

e) Close XV-103A and XV-103B.

NOTE: Unless the plant is in Idle, closing XV-103A and XV-103B will cause a plant ESD.

10. **On the King Count Operation Mode Control screen verify the PLANT STARTUP OPTION for AUTO STARTUP is set to MANUAL.**

11. **On the King County Plant Settings screen verify all settings using the PLANT SETTINGS table.**
    See "Startup to Hot standby plant settings" on page 6-32

Changing from SHUTDOWN to IDLE

CAUTION

Do not transition to IDLE unless you are prepared to restart the plant. Shutdown is a stable state.

1. **If a RAPID RESTART was in progress and not finished, verify Rapid Restart has been aborted.**
   Go to the OPMODE screen. If a red ABORT RAPID RESTART is displayed, the Rapid Restart has been aborted. If RAPID RESTART IS ACTIVE is displayed, abort the Rapid Restart by selecting the ABORT button on the OPMode screen.

2. **If shutdown conditions still exist, go to the alarm summary screen and acknowledge/clear all existing alarms.**

3. **On the S/D Trip screen and verify all S/D Trips are green. The HS-111A Software Switch may still be red at this time.**
   If any other trips exist, investigate and clear the condition that caused the trip before proceeding.

4. **On the S/D Trip screen, push the 1st OUT RESET button to reset the 1ST out pointer, and then press the FAIL MESSAGE RESET, if needed.**

5. **Reset the HS-111A software switch.**

6. **At the electrical balance of plant (EBOP) enclosure, press the SHUTDOWN RESET button (green HS-112).**

7. **On the King Count Operation Mode Control screen, select IDLE.**
   The box for IDLE will turn yellow, and the mode transition checklist will appear for IDLE MODE.

8. **Verify that the Plant Target Mode is IDLE and the Actual Plant Mode is EMERGENCY SHUTDOWN.**

9. **Verify IDLE mode transition checklist items are complete.**
   If text is blue with a red X, the operator must verify the step is complete and then click on

the blue text to change the red X to a green check mark.

If a red X is next to black text, when the DCS gets a signal that this step is complete it will change the red X to a green check mark. DCS may not automatically do this step so the operator may need to click on the black text to do this step.

10. **On the burner management system (BMS) panel, verify the EMERGENCY STOP (PB-62A/HS-231B) is pulled out, and then push the ACKNOWLEDGE (PB-246), RESET (PB-245), and ESD RESET (PB-62B) push buttons.**

11. **On the DCS, verify that the AGO SHUTDOWN button (HS-231A) does not have a shutdown signal. Reset the AGO shutdown if needed**.
    Open the AGO SHUTDOWN button and if HS-231A is green it needs to be reset. If HS-231A is red no shutdown signal is being sent to the AGO.

12. **Verify the DCS did the following pre-mode shift actions for IDLE MODE:**
    - HV-240 is closed.
    - XV-103A and XV-103B are closed to isolate natural gas to unit.
    - XV-820A and XV-820B are closed to isolate digester gas supply.
    - XV-191, XV-280, XV-282 and XV-284 closed to isolate purge and bleed nitrogen.
    - XV-247B and XV-260 closed and XV-247A and XV-262 open.
    - Cathode air blower (HS-224) is off with XV-241A closed.
    - Preconverter heater control (XS-195) is off.
    - Digester gas compressor (HS-800A) is off.
    - TC-120 is in manual with an output of –5.
    - On the water treatment system push WTS ALARM RESET button to reset the UA-406 alarm and verify a Water Treatment System Permitted (HY-404) is displayed.
    - Verify PCS OP MODE Target is GRID.
    - Verify XV-290 is closed.

13. **Verify the plant is now in IDLE mode.**
    When in IDLE mode, the box for IDLE will turn green.

14. **If needed, change out nitrogen six-packs and put the nitrogen bottles in service now.**
    "Operating the Nitrogen System" on page 6-78

15. **Check each of the anode cover gas bottle pressures (2) are greater than 1500 psig. Change out bottles that are less than1500 psig.**

Changing from IDLE to HEATUP-1

The startup skid is used to heat up the fuel cell stack. The ambient temperature is brought to 150°F on TI-240 at a ramp up rate of 15°F/hr. with an end point of 300°F. Once the AGO system is ready the startup skid equipment is shutdown the next heatup cycle begins. The startup skid heater and blower can be used to hold the fuel cell stack temperature above the minimum 150°F temperature while the AGO system is prepared for startup.

1. **Start up the startup skid.**
   See "Starting up the startup skid" on page 6-60.

2. **On the King Count Operation Mode Control screen select HEATUP-1.**
   The box for HEATUP-1 will turn yellow, and the mode transition checklist will appear for HEATUP-1 MODE.

3. **Start the startup blower.**
   On the local control panel, turn the motor switch to ON.

4. **Verify that the Plant Target Mode is HEATUP-1 and the Actual Plant Mode is IDLE.**

5. **Verify HEATUP-1 mode transition checklist items are complete.**
   If text is blue with a red X, the operator must verify the step is complete and then click on the blue text to change the red X to a green check mark.

   If a red X is next to black text, when the DCS gets a signal that this step is complete it will

change the red X to a green check mark. DCS may not automatically do this step so the operator may need to click on the black text to do this step.

6. **Verify DCS did the following pre-mode shift actions:**
   a) HV-240 opens 100% (HIC-240 output 100%).
   b) All other valves and controls will be in the same state used for Idle. (If any of the valves are not in position for Idle, as the valve position changes for Heat Up 1, an ESD may occur).
7. **Verify the plant is now in HEATUP-1 mode.**
   The box for HEATUP-1 will turn green when in the HEATUP-1 mode. Once the change to Heat Up 1 is complete verify TY-216B begins to ramp at 15°F/hr. with an end point of 300°F.
8. **Close HV-240 when TI-216 is greater than TI-240.**
9. **Turn on power to the preconverter heater control panel at the control panel.**
10. **Start the preconverter jacket heater from DCS (XS-195).**
    Once the heater is enabled, the heater is set for 900 °F internal temperature and the jacket heater is set to 1,050 °F; the over temperature shutoff is set at 1,100 °F on the control panel.
11. **Verify TDI-218 remains less than 100°F.**
    If TDI-218 gets to 100 °F, the TY-216B ramp is held until temperature differential is reduced.
12. **Verify HEATUP-1 is complete.**
    When HEATUP-1 is complete (TI-240 is >225°F) an alarm registers on the DCS.

    Verify the HEATUP-1 Mode Complete Actions on the HEATUP 1 Mode table.

CAUTION

TI 240 should not be allowed to go above 300°F because this could damage the startup blower. The heater rampup will continue to 300°F, unless the operator shuts off the heater. Leaving the heater on increases the time available to change from the startup heater heater and blower to the AGO burner and blower, without the stack temperature dropping below the minumum 150°F metal temperature.

Changing from HEATUP-1 or HOT RESTART to HEATUP-2(DG)

Cathode temperature is >150 °F on TI-240. HEATUP-2 NG, minimum is set to 880 °F on TC-238 with a ramp up rate of 15 °F/hr.

1. **When the desired temperature is reached, disable the startup heater ramp (TY-216B).**
   a) Turn the startup blower switch HS-220 to OFF.
   b) Isolate the startup heater by closing valves MV 2039 and MV 2040, and opening valve MV 2042 (startup heater drain valve).
2. **Once the AGO system is running, continue to turn off and isolate the startup heater and blower.**
   "Shutting down the startup skid" on page 6-60.

CAUTION

Do not allow anode cover gas flow for longer than 30 minutes without having the AGO air blower running. Because the atmosphere created by the cover gas could damage the fuel cell stack module if left in place.

3. **Verify AGO air blower interlocks are satisfied:**
   a) There are no remote plant ESD (all the hand switches on S/D Trips Screen are green).

b) Check for a BMS ESD trip by doing the following:
   - Verify the EMERGENCY STOP (PB-62A/HS-231B) on BMS panel (locally at the AGO) is pulled out.
   - Verify on the DCS that the AGO SHUTDOWN button (HS-231A) does not have a shutdown signal (Open the AGO SHUTDOWN button on the AGO screen. If HS-231A is green it needs to be reset. If HS-231A is red no shutdown signal is being sent to the AGO).
   - Then locally at the AGO on the BMS panel, push the ACKNOWLEDGE (PB-246), RESET (PB-245), and ESD RESET (PB-62B) push buttons.

c) There is no high vibration condition alarm (VAH-224) registering.

NOTE: Shortly after selecting HEATUP-2 NG the AGO blower will start. Monitor for proper blower startup at the DCS and locally.

4. Verify that the DG compressor motor and enclosure fans are in AUTO.

5. Verify valve MV-8001 is open.

6. Verify XV-241 is closed before selecting HEATUP-2 DG.
If it is opened before HEATUP-2 is selected, the change in the heatup status may cause a plant trip.

7. As soon as possible after selecting HEATUP-2, verify the DCS did the following:

a) Opened HV-240 (HIC-240 at 100%)

b) Opened XV-103A and XV-103B (anode natural gas supply)

c) Set temperature controller TC-120 in AUTO at 775°F

d) Turned XS-195 preconverter jacket heater on.

e) Valve XV-820 A/B is open when TC-238 is >685°F.

f) DG compressor starts

g) DG has been selected as the mode

h) Switch the methane oxygen analyzer (AT-100) suction/discharge valves to the digester gas lineup.

8. On the King Count Operation Mode Control screen, select HEATUP-2 DG.
The box for HEATUP-2 DG will turn yellow and the mode transition checklist will appear for HEATUP-2 DG MODE

9. Verify that the plant target mode is HEATUP-2 DG and the actual plant mode is HEATUP-1 (or HOT RESTART if doing a hot restart).

10. Verify the AGO blower outlet valve XV-241A opens, the blower starts and that the discharge pressure increases to about 28 inches W.C. (PC-222).
The blower will ramp to a total air flow of 900 scfm (FC-210) at a 28 inches W.C. discharge pressure.

11. Verify HEATUP-2 DG mode transition checklist items are complete as needed.
If text is blue with a red X, the operator must verify the step is complete and then click on the blue text to change the red X to a green check mark.

If a red X is next to black text, when the DCS gets a signal that this step is complete it will change the red X to a green check mark. DCS may not automatically do this step so the operator may need to do this step.

12. Once PDAL-233 resets (primary air flow pressure switch across FC-230), on BMS panel, start the AGO pilot as follows:

a) Press the SYSTEM STOP/RESET push-button.

b) Verify the LIMITS SATISFIED light is on.

c) Press SYSTEM LOCAL START push-button.

d) Check that the following happened (locally and on DCS):
   - Purge light is on (local only).
   - Purge lasted for 2 minutes.
   - After the purge finishes, the pilot gas valves XV-203 and XV-205 and pilot air valve XV-260 should open.

- Within 10 seconds the pilot should light, indicated by the UV flame scanner (BE-233) light coming on.

13. **Once the pilot is lit, verify that FC-210 resets to 3,500 scfm and is in AUTO.**

14. **Verify HV-240 closes as TC-238 becomes greater than TI-240.**

15. **When FC-210 exceeds 2,000 scfm verify:**

    a) XV-212 and XV-214 are open.

    b) The main burner is lit.

    NOTE: If the plant has been shutdown for a long time, then BE 243 may not immediately indicated a flame. As long as either the main burner or pilot is on, BE 233 will show a flame.

    c) XV-203 and XV-205 are closed.

16. **Verify the plant is now in HEATUP-2 DG mode.**
    The box for HEATUP-2 DG will turn green when it is in the HEATUP-2 DG mode.

17. **Monitor plant parameters for abnormalities and be sure the ramps happen as follows:**

    a) TY-238B will begin to ramp at 15°F/hr. until TC-238 reaches 885°F; TC-238 (cathode inlet temperature) and FC-208 (fuel gas to AGO burner) will change to CASCADE.

    b) TY-238B ramp will hold if TC-238 reaches 700°F and the preconverter catalyst bed temperature (TI-142) is <600 °F or the oxidizer catalyst bed temperature is <1,000 °F.

    c) As the oxidizer outlet temperature, TC-238 rises above 500 °F, TY-244C will enable and TC-245 will raise the catalyst temperature to >1,000 °F at 30 °F/hr. Then TC-245 will change to CASCADE and control the tertiary air valve TV-245 and maintain the ramp set point.

    d) Once catalyst outlet temp, TC-244, reaches 1,000 °F, TY-244C will maintain catalyst temperature at >1,000 °F (the TY-244C end value will be 1,010 °F).

18. **Start the anode and fuel gas line heat traces.**
    Close breakers CB-161F and CB-163A. Check that breakers 163B, 163C, 163D, 163E, 163F, and 163G are closed.

19. **Verify that the digester gas and water treatment systems are lined-up, and operating and ready to supply water. Verify water valve MV-4042 is open, the digester gas valve lineup is complete and the digester gas compressor is running, before the following six things happen:**

    - Preconverter catalyst bed temperature (TI-142) is >600 °F.
    - Oxidizer catalyst bed temperature is at or >1000 °F on TC-244, which is the average of TI-244A/B/C temperatures.
    - HRU stack exhaust temperature (TI-125) is >500 °F.
    - Anode inlet low low temperature alarm (TALL 331) is above 300 °F.
    - Anode outlet valve XV 262 opens.
    - When TC-238 is >685 °F, XV-820A/B will open and the compressor will start.

20. **Once the above six-conditions are met, verify anode fuel flow is established.**
    Water should begin to flow using FC-131, and fuel should begin to flow using FC-117[1] (minimum valve based on plant settings page) to maintain a steam-to-carbon ratio of 8:1. FC-131 and FC-800 should be in cascade. When HEATUP-2 (TC-238 at 885°F) is finished, a Sequence Alarm is actuated in DCS and plant will hold at the TY-238B ramp end value.

Changing from HEATUP-2 DG to HEATUP-3 DG

The cathode temperature is >880 °F on TI-238. To change to HEATUP-3 NG (880°F to 960°F on TC-238) the system will use a a ramp up rate of 12°F/hr.

1. **Verify the ramp rate in the Plant Settings table, check the heatup (HU)/cooldown (CD) temperature ramp rates for HU3 and CD2 is 12 (deg F/hr.).**

1. Should this be FC-800?

2. **On the King Count Operation Mode Control screen, select HEATUP-3 DG.**
   The box for HEATUP-3 DG will turn yellow and the mode transition checklist will appear for HEATUP-3 DG mode.

3. **Verify the plant target mode is HEATUP-3 DG and the actual plant mode is HEATUP-2 DG.**

4. **Verify HEATUP-3 DG mode transition checklist items are complete.**
   If text is blue with a red X, the operator must verify the step is complete and then click on the blue text to change the red X to a green check mark.

   If a red X is next to black text, when the DCS gets a signal that this step is complete it will change the red X to a green check mark. DCS may not automatically do this step so the operator may need to do this step.

5. **Verify the plant is now in HEATUP-3 DG mode.**
   The box for HEATUP-3 DG will turn green when in the HEATUP-3 DG mode.

6. **Verify in DCS that TY-244C is in RAMP ENABLED, RAMP NOT PAUSE, TRACK OFF with end value of 1010°F and TY-238B is in RAMP ENABLED, RAMP NOT PAUSE, TRACK OFF with an end value of 990°F.**
   Change the track on/off as necessary.

7. **Verify the DCS did d the following mode shift actions for Heatup-3 NG:**
   a) XS-195 (preconverter jacket heater) is on.
   b) TC-238 will remain in cascade.
   c) TC-243 will remain in manual with a set point of 1.0.
   d) FC-800 will remain in cascade.
   e) FC-131 will remain in cascade.
   f) FC-208 will remain in cascade.
   g) FC-210 will remain in auto with a set point of 3500 scfm.
   h) FC-230 will remain in cascade.
   i) TC-245 will remain in cascade.
   j) TC-244 will remain auto.
   k) TC-120 will remain in auto with a set point of 1,000 °F.

8. **Using TC-238, monitor the heat up to verify it is actually ramping up at 12°F/hr.**

9. **Verify that temperature holds for 4 hours at 990°F (the end point of Heat up 3).**
   This heat soak will make sure that at the end of electrolyte melt the temperatures throughout the stack are even.

10. **When HEATUP-3 is complete an alarm is actuated in DCS.**

Changing from HEATUP-3 DG to HEATUP-4 DG

The cathode temperature is >990 °F on TC-238 and TI-240. HEATUP-4 DG will raise the temperature from 985 °F to 1,105 °F on TC-238, with a ramp up rate of 15 °F/hr.

1. **On the King Count Operation Mode Control screen, select HEATUP-4 DG.**
   The box for HEATUP-4 DG will turn yellow and the mode transition checklist will appear for HEATUP-4 DG mode.

2. **Verify the plant target mode is HEATUP-4 DG and the actual plant mode is HEATUP-4 DG.**

3. **Verify the HEATUP-4 DG mode transition checklist items are complete.**
   If text is blue with a red X, the operator must verify the step is complete and then click on the blue text to change the red X to a green check mark.

   If a red X is next to black text, when the DCS gets a signal that this step is complete it will change the red X to a green check mark. DCS may not automatically do this step so the operator may need to do this step.

4. **Verify the plant is now in HEATUP-4 DG mode.**
   The box for HEATUP-4 DG will turn green when in the HEATUP-4 DG mode.

5. **Verify in DCS that TY-244C is in RAMP ENABLED, RAMP NOT PAUSE, TRACK OFF; and TY-238B is in RAMP ENABLED, RAMP NOT PAUSE, TRACK OFF with an end value of 1110 and a ramp rate of 15°F/hour.**
   Change the track on/off as necessary.

6. **Verify the DCS did the following mode shift actions for HEATUP-4 NG.**
   a) XS-195 (preconverter jacket heater) is on.
   b) TC-238 will remain in cascade.
   c) TC-243 will remain in manual with a set point of 1.0.
   d) FC-800 will remain in cascade.
   e) FC-131 will remain in cascade.
   f) FC-208 will remain in cascade.
   g) FC-210 will remain in auto with a set point of 3500 scfm.
   h) FC-230 will remain in cascade.
   i) TC-245 will change to auto with set point 500.
   j) TC-244 will remain in auto.
   k) TC-120 will remain in auto with a set point of 775°F.
7. **Using TC-238, monitor ramp up to verify it is actually ramping up at 15°F/hr.**
8. **When HEATUP-4 is finished an a alarm registers on the DCS.**

Changing from HEATUP-4 DG to HOT STANDBY DG

Heatup 4 is the ramp up from 985°F to 1,105°F. The cathode temperature is >1,050 °F on TC-240. The change to Hot Standby is when conditions are steady and TC-238 is about 1,110°F. The end of HEATUP-4 DG is essentially the same as HOT STANDBY DG.

1. **On the King Count Operation Mode Control screen verify that "EXTENDED HOTSTANDBY" is NO.**
2. **On the King Count Operation Mode Control screen select HOT STANDBY DG.**
   The box for HOT STANDBY DG will turn yellow and the HOT STANDBY DG mode transition checklist will appear.
3. **The plant target mode is HOT STANDBY DG and the actual plant mode is HEATUP-4 DG.**
4. **Verify HOT STANDBY DG mode transition checklist items are complete.**
   All blue and black text are followed by a green check mark.

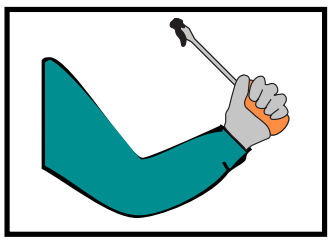
   If text is blue with a red X, the operator must verify the step is complete and then click on the blue text to change the red X to a green check mark.

   If a red X is next to black text, when the DCS gets a signal that this step is complete it will change the red X to a green check mark. DCS may not automatically do this step so the operator may need to do this step.
5. **Verify the DCS did the following mode shift actions for Hot Standby.**
   a) XS-195 (preconverter jacket heater) is OFF. (May be turned on if needed to maintain the catalyst temperature).
   b) TC-238 will change to auto with a set point of 1110.
   c) TC-243 will remain in manual with a set point of 1.0.
   d) FC-800 will remain in cascade.
   e) FC-131 will remain in cascade.
   f) FC-208 will remain in cascade.
   g) FC-210 will remain in auto with a set point of 3500 scfm.
   h) FC-230 will remain in cascade.
   i) TC-245 will remain in auto with a set point of 500.
   j) TC-244 will remain in auto.
   k) TC-120 will remain in auto with a set point of 775 °F.
6. **At completion of HOT STANDBY sequence a DCS alarm is actuated.**
7. **Maintain HOT STANDBY until plant is placed on load (producing power) or plant needs to be changed to cooldown mode, or extended Hot Standby.**

Startup to Hot standby plant settings

Proprietary information— Not Available for Publication.	

Reference



6.7 KCPP Power Generation

Once the plant is in Heatup 4 or Hot Standby the system is ready to begin generating power. There is a reduced and a full power load setting, normally full power load is used unless there is a problem with the fuel cell system.

Initial conditions

- Cathode inlet temperature (TC-243) has been greater than 1,070°F for at least 3 hours before asking for a load ramp.
- The plant is in Hot Standby NG/DG.
- Plant temperature (TI-240) is greater than the minimum temperature for Hot Standby (Normally >1,050°F).
- Total airflow about 3,500 scfm.

CAUTION

Hot Standby must be maintianed for 2, 4, or 12 hours depending on the plants condition to protect the fuel cell stack.

Before going to Power Generation the fuel cell must have been in Hot Standby for at least 12 hours if:

- This is the first time entering Power Generation after an electrolyte melt

or

- This is a trip recovery and any of the cathode out elbow temperatures (TE-333A/B/C/D) cooled below 900°F following the trip.

Before going to Power Generation the fuel cell must have been in Hot Standby for at least 4 hours if:

- This is a trip recover, and emergency shutdown (ESD) or a Hot Standby trip.

and

- It has been more than one hour since the plant tripped.

Before going to Power Generation the fuel cell must have been in Hot Standby for at least 2 hours if:

- This is a trip recover, and emergency shutdown (ESD) or a Hot Standby trip.

and

- It has been less than one hour since the plant tripped.

Changing from HOT STANDBY to Grid Power Generation

1. **On the Op mode screen select the FULL power mode.**

NOTE: Power mode is normally FULL unless required by other operating conditions. On the plant settings page when the indication shows REDUCED, FULL is actually selected, this can be checked by going to the OP MODE screen and seeing if FULL is displayed next to the FULL/REDUCED selector.

2. **Enter the estimated auxiliary load.**
   Determine the auxiliary loads by going to the EBOP screen and checking the Aux Load Readings KW Demand, then enter the value as the ESTIMATED AUX LOADS (KW) on the Plant Settings screen.

3. **Verify the following plant settings and conditions:**

   a) On the EBOP screen, verify the Target Mode is in Grid Mode.

   b) On the Plant Settings screen, the Normal KW Rate of Change (KW/min.) is set to 2.

   c) On the Plant Settings screen, the Fuel Cell Full Power setting is set to desired final KW value.

   d) On the Plant Settings screen, Fuel Cell Reduced Power setting is set to about 75-percent of the full power setting.

   e) On the Plant Settings screen, set the minimum current to secure AGO flame in power generation mode to 1,670 amps.

   f) On the EBOP screen, the Power Factor Set point to PCS (HC-330) is in manual mode with an output value of 1.00.

g) On the EBOP screen put NET POWER TARGET (for IC-320) in manual with a set point of 1.00 or Power/Fuel screen, put IC-320 in manual with a set point of 1.00.

h) On KCPP M10 Stack Voltages screen select the red RAMP CND button, and then select the YES button. The RAMP CND button should turn green when active.

i) Verify the ENABLE VOLTAGE SAFETY SWITCH status is ENABLED.

4. Verify the inverter fans are running.
Breakers CB-160B and CB-160C shut, and a local fan noise can be heard.

5. Enable the DC contactors (HS-301 on the EBOP screen).

CAUTION

Do NOT operate the DC input breakers. The DC input breakers should never be opened under load because it will damage the breakers.

6. Close each inverter DC input breaker (except inverter 4 which will not be used).
Go to each inverter and hold the breaker in the mid position for 5 seconds, then go to close position. These breakers is located on the top left of each inverter.

7. On the King Count Operation Mode Control screen select GRID POWER NG.
The box for GRID POWER NG will turn yellow and the mode transition checklist will appear for GRID POWER NG.

8. Verify the plant target mode is GRID POWER and the actual plant mode is HOT STANDBY.

9. Verify GRID POWER mode transition checklist items are complete.
All blue and black text should be followed by a green check mark.

If text is blue with a red X, the operator must verify the step is complete and then click on the blue text to change the red X to a green check mark.

If a red X is next to black text, when the DCS gets a signal that this step is complete it will change the red X to a green check mark. DCS may not automatically do this step so the operator may need to do this step.

10. Verify the DCS did the following mode shift actions for GRID POWER NG.

a) Verify the power control system (PCS) starts, go to the EBOP screen and verify the current is greater than zero and rising on II-310A/B/C/D.

b) Verify that the inverters have gone ON with the exception of inverter 4. (Normally inverters 1-3 will start at 10-second intervals.)

c) Verify the output breaker has closed on the inverters that are on. This will indicate the grid is connected.

d) Verify the preconverter jacket heater has turned off.

e) Verify that TC-238 has changed to cascade with a set point of 1110°F.

f) Verify TC-243 has changed to cascade with a set point of 1.0 (TC-243 will not begin to actively control temperature until AGO flame is off).

g) FC-117 or FC-800 remained in cascade.

h) FC-131 remained in cascade.

i) FC-208 remained in cascade.

j) FC-210 will change to cascade.

k) FC-230 remained in cascade.

l) TC-120 remained in auto with a set point of 775°F.

11. Verify that FC-210 has begun to ramp down to the value required by current power generation target value.
FC-210 will attempt to ramp down to a value on FY-210A Look Up Table, plus the minimum airflow boost for AGO flame from the Plant Settings screen. The final ramp down value of FC-210 is also affected by FY-246 (total AGO air to fuel ratio), so the actual airflow may be higher than what is required by FY-210A at low amp demands. Table FY-210A lists the airflow vs. current (amps) demand and is found on the Air/Fuel screen at FY-117A.

12. Verify that FC-117 or FC-800 has adjusted the fuel flow based on current (amps)

demand (or minimum required per the plant settings screen).
The required fuel flow can be found on the Power/Fuel screen at FY-117A. The steam-to-carbon ratio may also limit the fuel flow. The required steam-to-carbon ratio can be found as a look up table FY-131B on the Power/Fuel screen. Watch that the fuel and water valves respond correctly.

13. **Verify plant is ramping at 2 kW/min.**

14. **Verify that the plant is now in GRID POWER NG mode.**

15. **Monitor the plant during load ramps and steady state operation using the next section of this procedure Operating in Power Generation.**

Operating in Power Generation (grid power only)

1. **Maintain a maximum ramp rate 2 kW/min.**

2. **Monitor and maintain the following cell differential pressures:**

   a) Maintain PDI-254 (cathode out to anode out) as low as possible. A reduced power trip will happen if this value gets to 17 in W.C. and an ESD will happen at 19 in W.C.

   b) Maintain PDI-255 (fuel cell shell pressure to cathode outlet) below high alarm. The high alarm for this parameter is set to 12.5.in. W.C.

   c) Monitor the three differential pressure gauges PDT-340A,B, and C, the differential pressure should stay between 6 and 8 inches W.C.

3. **Monitor cell voltages before any load ramp.**

   a) Select the red RAMP CND button on the KCPP M10 Stack Voltages screen. The RAMP CND buttons will turn green when active.

   b) Check that the deviation readings on the stack voltage deviation monitor are below the specified limits.

   c) Verify the ENABLE VOLTAGE SAFETY SWITCH status is ENABLED.

4. **During the load ramp monitor the cell voltages as follows:**

   a) For the large cell groups, (cells #5-61, cells #62-118, cells #119-176, cells #177-234, cells #235-291, cells #292-348):

      1) Verify the cell group voltage deviations from the original cell group voltage deviations is less than –9mV (it should not become more negative) The DCS automatically registers a warning that the change in deviation is more than –9 mV from the original (steady state) cell group voltage deviation.

      2) If change in deviation is more than –9 mV (more negative), stop the load ramp and notify FCE management.

   NOTE: If the change in deviation is more than –11 mV (more negative) for 5 minutes the plant will automatically trip to Hot Standby.

   b) For small cell groups (cell #1-4, cells #398-400, cell #400 and cell #1):

      1) If these average cell voltages drop to –750mV notify the FCE management.

   NOTE: If these average cell voltages drop below 700mV for 5 minutes the plant will automatically trip to Hot Standby.

5. **During a load ramp, when 1,670 total amps are reached, monitor whether the pilot is coming on and the main AGO burner is shutting off.**

   a) Check XV-203 and XV-205 are open.

   b) After 10 seconds XV-212 and XV-214 should close.

   c) Verify the flame scanner BE-233 remains lit.

NOTE: If the pilot and main burner go off (BE-233 and BE243 indicate no flame) the plant will continue to operate as long as the power generation produces enough heat to maintain the required temperatures. If the plant temperatures drop and the pilot and main are needed a plant emergency shutdown (ESD) is needed to restart the pilot/main burner.

6. **Maintain the cell temperature during ramp up and steady state conditions as follows:**
   a) If the in-cell differential temperature (applies to individual stack on load) is:
      - Less than 175 °F (high alarm) contact FCE management for direction
      - Less than 200 °F (high high alarm) and there is a ramp in progress — hold the ramp.
   b) If the cell K or P the in-cell differential temperature (applies to individual stack on load) is:
      - Less than 70 °F (high alarm) contact FCE management for direction
      - Less than 80 °F (high high alarm) and there is a ramp in progress — hold the ramp
   c) If the cathode outlet elbow temperature (TI-333A/B/.C/D are less than 1180 °F

      _____

   d) During load ramps and steady state conditions check the maximum in-cell temperatures, a high alarm occurs if any in-cell temperature reaches:
      - <60 mA/cm^2 at 1,190 °F.
      - <80 mA/cm^2 at 1,200 °F
      - <100 mA/cm^2 at 1,210 °F
      - <110 mA/cm^2 at 1,220 °F
      - >110 mA/cm^2 at 1,230 °F

      A high high alarm occurs at 1,285°F.
7. **Verify the I deadbands on the face plate details screen for the following controls.**
   a) Verify the change to 1 for FC-117.
   b) Verify the change to 2.5 for FC-131.
8. **30-minutes after a load ramp has finished, check the STK VOLT DEV MONITOR to verify deviations are below limits.**
   If the change in the deviation is more than –3mV (more negative), notify FCE management. If the deviation is more than –5 for 5 minutes the fuel cell will automatically trip to Hot Standby

   For small cell groups (cell #1-4, cells #398-400, cell #400 and cell #1): If these average cell voltages drop to –750mV notify the FCE management.If these average cell voltages drop below 700mV for 5 minutes the plant will automatically trip to Hot Standby.
9. **On the KCPP M10 Stack Voltages screen, select the read STEADY CND button.**
   The STEADY CND button turns green when it is active.
10. **Print out screen shots for the general conditions (GCs) and other operation data as needed.**

Changing power level in Power Generation (grid power only)

1. **Verify on the Plant Settings screen that FULL POWER is selected.**
2. **Change the power output as follows:**
   a) Print the required screen shots, GC's and other operational data as needed.
   b) Verify IC-320 is in AUTO.
   c) On the Plant Settings screen change the fuel cell full power setting to the desired full power output. Once you confirm the setting change, the plant will begin to ramp to desired power level.
   d) Verify the I Deadbands for the following controls:
      1) On FC-117 (Face Plate Details screen) verify it to 0.5 for the ramp. (Normally during steady load conditions, this set to 1.0).
      2) On FC-131 (Face Plate Details screen) verify it to 1.0 for the ramp. (Normally during steady conditions, this is set to 2.5).
   e) On the KCPP M10 Stack Voltages screen select the red RAMP CND button. The RAMP CND button turns green when it is active.
   f) Verify the ENABLE VOLTAGE SAFETY SWITCH status is ENABLED.
   g) Monitor the fuel cell operation. "How monitor a dV/cell" on page 6-12.

3. **Operate the AGO system.**
   Operate it as you did in "Changing from HOT STANDBY to Grid Power Generation" on page 6-34

Responding to a reduce power trip in Power Generation (grid power only)

1. **If a reduce power trip happens check the following items that could have caused it:**
   a) Humidifier outlet temperature low alarm (TAL-121), TI-121 at 750°F or less.
   b) DC current difference high alarm (IDAH-310). This trip happens if an individual stack current has a 10% deviation from the average current of the stacks for at least 60 seconds.
   c) Cathode to anode differential pressure high alarm (PDAH-254), PDI-254at 17 inches W.C. or higher.
   d) Cathode inlet temperature high alarm (TAH-238), TC-238 at 1,130 °F or higher.
2. **Once a power trip happens be sure the power begins to ramp down to the reduced power setting at the rate specified in the Rapid KW Rate of Change (8 kW per minute).**
   This is found on the Plant Settings screen.
3. **Monitor the plant for proper response to the power ramp down.**
4. **Go to the S/D Trips screen to determine the cause of the reduced power trip.**
5. **Determine and correct the cause of the reduced power trip.**
6. **Once the problem causing the reduced power trip has been corrected do "a" if the plant has is at reduced power setpoint, or "b" if the plant is still ramping down.**
   a) To return to full power select FULL on the OP Mode screen full/reduced power selector.
   b) To stop the ramp down, put the plant on hold:
      1) Go to the KCPP OP Mode screen and select PLANT MASTER HOLD. It will have PLANT HELD beside it when plant is on hold. To return to desired power:
      2) Set the full power and reduced power settings on the Plant Settings screen to the desired power level.
      3) On the KCPP OP Mode screen, select FULL POWER on the full/reduced power selector.
      4) Select PLANT MASTER HOLD and take the plant out of hold. It will have PLANT NOT HELD beside it when the hold is released.
   c) Continue plant operation per the Plant Operations in Power Generation mode. "Operating in Power Generation (grid power only)" on page 6-36
7. **Once the cause of the trip has been found and corrected, reset the 1st Out Reduced Power Trip.**

Responding to a Trip to Hot Standby in Power Generation (grid power only)

1. **If a trip to Hot Stand By happens, check the following items that could have caused it:**
   a) Humidifier outlet temperature low low alarm (TALL-121), TI-121 at 650°F or less.
   b) DC current difference high alarm (IDAH-310) for 120 seconds. This trip happens if an individual stack current has a 10% deviation from the average current of the stacks for at least 120 seconds.
   c) PCS has tripped (UA-351 and UA-350).
   d) PCS communications failure.
   e) Preconverter inlet (HRU damper control) temperature low-low alarm (TALL-120), TC-120 at 650°F or lower.
   f) Preconverter differential temperature high-high alarm (TDAHH-140), differential at –100°F or higher.
   g) Blown fuse HS-301. (This is not yet a clearly defined trip, registers as a DC connector trip signal or it maybe a ground fault)

h) Manual trip by an operator. (The TRIP TO HOT STANDBY button is only available in Power Generation).

i) Stack current deviations alarm (IDAH-310). A percent deviation between current set point and actual current.

j) Voltage deviation low low alarm while ramping (see the operations section).

k) Voltage deviation low low alarm while in a steady state (see the operations section).

l) Small group low low voltage trip (see the operations section)

2. If a trip to Hot Standby happens or starts verify the following:

a) Plant output goes to zero. This can be verified on the EBOP screen using II-310A/B/C/D.

b) The EBOP AC output circuit breakers have opened.

c) The AGO main burner starts.

d) TC-238 shifts to Manual with an output setting of the following equation: 78 –((3,500-FC210PV) /45) – (-2). This equation determines the TC-238 output value. TC-238 will stay in manual with this output value until FC-210 is a 3,475 scfm or greater and TC-238PV is greater than 1,105°F. If and when these two conditions are met, TC-238 will then shift to AUTO with a set point of 1,111°F. A plant emergency shutdown (ESD) happens if TC-238 drops below 960°F.

e) If needed, put TC-238 in manual, by press the DISABLE button next to the TC-238 face plate, and raise output to the prevent cell temperature from dropping excessively.

NOTE: It is important to maintain the TC-238 temperature, since this will directly affect the other parameters that lead to a plant emergency shutdown such as TI-331 low-low alarm at 960°F or EI-341 low total stack voltage alarm at 234 VDC.

f) Verify that FC-210 changes to AUTO. with the pre-trip set point. FC-210 will hold on this set point until either TC-230PV is ≥ 1,110 °F, or FC-208 PV is ≥ TC-238's output. Once one of the to conditions are met FC-210 changes from HOLD to AUTO with a set point of 3500 scfm.

g) If needed, put FC-210 in manual to stop the blower ramp up, or lower it if necessary, to help maintain TC-238 temperature as close to 1,110°F as possible.

h) On the King County operation control mode screen verify that EXTENDED HOT STANDBY is NO.

3. Verify that the DCS did the following shift actions for Hot Standby.

a) The PCS is OFF. Go to the EBOP screen and verify cell currents are zero (or as close to zero as it gets) on II-310A/B/C/D.

1) Verify XS-195 (preconverter jacket heater) is OFF.

2) Verify TC-243 is still in manual with a set point of 1.0.

3) FC-117 or FC-800 should change to manual with an output of zero for 5 seconds and then return to AUTO using the fuel flow set point. After 10 seconds, the logic should be complete and the controller will return to CAS with an fuel flow out put of 12 scfm. The steam-to-carbon (S/C) ratio will change from 2:1 to 8:1 after a 10 second delay.

4) FC-131 should be in cascade.

5) FC-208 should be in cascade.

6) FC-230 should be in cascade.

7) TC-245 should be in AUTO with a set point of 500.

8) TC-244 should be in AUTO.

9) TC-120 should be in AUTO with a set point of 875 °F.

b) Be sure the steam-to-carbon ratio is about 6.7 to 1 and fuel flow has reduced to about 12 scfm.

NOTE: When the hot standby sequence is finished an alarm registers on the DCS.

c) Once the cause of the trip has been found and corrected, reset the 1st Out Hot Standby Trip.

d) Check on the KCPP M10 Stack Voltage screen to be sure that the RAMP CND and STEAD CND buttons are both red (disabled)

e) Disable the DC contactors (HS-310 on the EBOP scree).

f) Verify the I-deadbands for FC-117 have been reset to 1.0, and FC-131 reset to 2.5; FC-800 does not change.

4. **Stay in Hot Standby until plant is placed back on load, changed to cooldown mode, or changed to extended hot standby.**

Changing from Grid Power Generation to Hot Standby

NOTE: In Grid Power Generation, selecting Hot Standby from the OP Mode screen will cause the plant to start ramping down power at 2 kW/min. until the gross power is <25 KW. Any faster load reduction rate must be approved by FCE management. If the load needs to be reduced immediately then consider a a trip to HOT STANDBY.

1. **Verify the following conditions:**

   a) The plant target mode is GRID POWER and the actual plant mode is GRID POWER.

   b) The plant is in Power Generation mode.

   c) On the Plant Settings screen, verify the Power ROC is set to 2 kW/min. (unless a faster ramp rate has been approved).

2. **On the King County operation control mode screen, select HOT STANDBY NG.**
   The box for HOT STANDBY NG will turn yellow and the mode transition checklist will appear for Hot Standby NG.

3. **Verify the ramp rate is 2 KW/min.**

4. **Verify AGO main burner starts when power is below the point (1,670 amps) where the main burner is needed.**
   Be sure TC-238 begins to ramp the output to control the AGO outlet temperature (TC-238) as needed for load conditions. If needed, put TC-238 in manual and raise output to prevent the cell temperature from dropping excessively.

   NOTE: When TC-238 and TI-331 are at 960°F a plant emergency shutdown (ESD) will happen.

5. **During mode shift, when FC-210 changes to auto with a set point of 3500 scfm maintain TC-238 temperature as close to 1130°F as possible.**
   If needed, put FC-210 in manual to stop the blower ramp up or lower the rate if necessary to maintain 1,130°F at TC-238.

6. **Verify the plant target mode is HOT STANDBY NG and the actual plant mode is GRID POWER.**

7. **Verify Hot Standby Mode Transition Checklist items are complete.**
   All blue and black text should be followed by a green check mark.

   If text is blue with a red X, the operator must verify the step is complete and then click on the blue text to change the red X to a green check mark.

   If a red X is next to black text, when the DCS gets a signal that this step is complete it will change the red X to a green check mark. DCS may not automatically do this step so the operator may need to do this step.

8. **On the King Count Operation Mode Control screen, verify that EXTENDED HOTSTANDBY is NO.**

9. **Verify the DCS did the pre-mode shift actions for HOT STANDBY NG.**

   a) When gross power is less than 25 kW verify the PCS is OFF. Go to the EBOP screen and verify cell currents are zero (or as close to zero as it gets) on II-310A/B/C/D and the inverters are OFF.

   b) Verify that XS-195 (preconverter jacket heater) is OFF.

10. **Verify the DCS did the pre-mode and mode shift actions for HOT STANDBY NG.**
    Some actions may not happen until actually in HOT STANDBY mode.

    a) TC-238 should be in auto with a set point of 1110.

b) FC-210 will change to auto with a set point of 3500.

c) TC-243 will change to manual with a set point of 1.0.

d) FC-117 or FC-800 should be in cascade.

e) FC-131 should be in cascade.

f) FC-208 should be in cascade.

g) FC-230 should be in cascade.

h) TC-245 should be in auto with a set point of 500.

i) TC-244 should be in auto.

j) TC-120 should be in auto with a set point of 775 °F.

11. Verify the plant responding normally as the blower ramps up to the Hot Standby airflow.

12. Verify the steam-to-carbon ratio is about 6.7 to 1 and fuel flow has reduced to about 10 scfm.

NOTE: When the HOT STANDBY sequence an Alarm is actuated in DCS.

13. Maintain HOT STANDBY until plant is put back on load, or changed to cooldown.

CAUTION

Never open the DC input breakers under load because the breakers can be damaged.

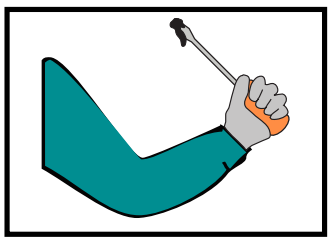
14. If power generation is no longer be needed do the following as needed:

a) Verify the inverter output breakers are open, and the inverter is off. Then open the DC input breaker.

b) Disable the DC contactors; disable HS-301 on the EBOP screen.

c) Turn off the inverter fans; open breakers CB-160B and CB-160C.

Reference



6.8 KCPP Trip Recovery Procedure

The plant has shutdown due to a plant trip also called an emergency shutdown (ESD), on the DCS computer the plant target mode is EMERGENCY SHUTDOWN and the actual plant mode is EMERGENCY SHUTDOWN. First you will find out what alarm actually tripped the shutdown, secondly find out what happened after the trip, what is the current plant status. Then print out all the alarms before you troubleshoot or acknowledge any alarms, and determine how you will restart the plant.

Trip recovery

1. Verify the DCS did the emergency shutdown actions listed below:

a) Go to the EBOP screen and verify the power conditioners (XS-351B) are off.

b) Verify HV-240 is shut. Close if necessary.

NOTE: If a RAPID RESTART was in progress, verify it was aborted. Go to the OP MODE screen, if a red ABORT RAPID RESTART is displayed the rapid restart has been aborted.

If RAPID RESTART IS ACTIVE is displayed the Rapid Restart is active, abort it now, then manually close HV-240.

c) Verify XV-103A and XV-103B are closed to isolate natural gas to unit.

d) Verify XV-820A and XV-820B are closed to isolate digester gas supply.

e) Verify the cathode air blower shutdown and XV-241A closed to isolate the air blower.

f) Verify the AGO Main and Pilot Flames are off (BAL-233 and BAL-243 off).

g) Verify the preconverter heater control (XS-195) is off.

h) Verify the digester gas compressor (HS-800A) is off.

i) Verify WTS product pumps are off (HY-407 STOPPED).

j) Verify the natural gas heater is disabled at the DCS. Verify at the local control panel that the high limit trip light is off; if not, reset the trip.

k) Verify nitrogen and cell isolation valves operated as follows:

1) Anode outlet block valve (XV-262) remains open and anode outlet vent valve (XV-260) remains closed for 10 minutes to prevent a transient anode overpressure condition. After 10 minutes, XV-260 opens and XV-262 closes.

2) Anode inlet valve (SV-247) stays open, and anode inlet vent valve (XV-247B) remain closed.

3) FC-131 and FC-117 (or FC-800) are closed.

4) Anode outlet block valve (XV-262) closes 10 minutes after an emergency shutdown (ESD).

5) Anode outlet vent valve (XV-260) opens 10 minutes after an ESD.

NOTE: Be sure the nitrogen 6-packs are not isolated for the following two steps.

6) XV-280 and XV-284 open to supply slow purge nitrogen to both the anode and cathode to minimize air intrusion into the system as the plant cools down.

7) When T320 median (displayed on OP MODE screen as TI-320 MED “BEST TEMP”) drops below 650 °F, and it is confirmed that valves XV260 and SV-247B are open and SV-262 and SV-247A are closed, XV-282 and XV-191 will open to initiate a fast nitrogen purge.

l) If the trip was due to a complete loss of grid power, verify the DC controller is disabled, if not disable it now.

2. Determine the cause of the shut down.
Go to the Shutdown Trips screen, look for the First Out trip condition, indicated by the yellow arrow, and read the fail message.

3. **From control studio, print the shutdown trips page showing the First Out trip, then the SD_ILOCK and the TRIPTRAP pages.**
4. **Print out the required screen shots on the Required Screen Prints Table.**
   "Required screen prints table" on page 6-45
5. **Correct the cause of the plant trip before proceeding.**

Preparing to restart after an ESD

The plant target mode is emergency shutdown and the actual plant mode is emergency shutdown. Prepare the plant for restart by doing the following.

1. **If the plant trip was due to a complete loss of grid power then do the following, if not skip to the next step.**
   a) Reset relay F60.
   b) Reset and close the tie-breaker.
   c) Start the instrument air system.
2. **Before to changing modes, verify the following systems are operating properly by checking the DCS screens:**
   - water treatment system
   - instrument air
   - safety and fire protection
3. **On the King County Operational Mode Control screen verify the PLANT STARTUP OPTION for auto STARTUP is set to manual.**
4. **On the King County Plant Settings screen verify all settings match the plant settings table.**
   "" on page 6-32.

Changing from SHUTDOWN to IDLE

1. **If a Rapid Restart was in progress and not completed, verify the rapid restart is aborted.**
   Go to the OP MODE screen. A red ABORT RAPID RESTART should be displayed, if RAPID RESTART IS ACTIVE is displayed the Rapid Restart still needs to be aborted.
2. **If shutdown condition still exists, go to the alarm summary screen and acknowledge/clear all existing alarms.**
3. **Go the S/D Trip screen and verify all S/D Trips are green. The HS-111A Software Switch may still be red at this time.**
   If there are other trips, investigate and clear the condition causing the trip condition before proceeding.
4. **On the S/D Trip screen push the 1st OUT RESET button to reset the first out shut down, and then push the Fail Message RESET.**
   Yellow arrow marks first out.
5. **Reset the HS-11A software switch.**
   Select RESET.
6. **Reset the MSG and the TRIP TRAP.**
7. **Go to the EBOP and press the green SHUTDOWN RESET button (HS-112)**
8. **On the King County Operation Mode Control screen select IDLE.**
   The box for IDLE will turn yellow and the mode transition checklist for IDLE mode will display.
9. **Verify the plant target mode is IDLE and the actual plant mode is EMERGENCY SHUTDOWN.**
10. **Verify the Idle Mode Transition Checklist is complete.**
    All blue and black text should be followed by a green check mark.

    If text is blue with a red X, the operator must verify the step is complete and then click on the blue text to change the red X to a green check mark.

    If a red X is next to black text, when the DCS gets a signal that this step is complete it will change the red X to a green check mark. DCS may not automatically do this step so the operator may need to do this step.
11. **On the BMS panel, verify the EMERGENCY STOP (PB-62A/HS-231B) is pulled out and then push the ACKNOWLEDGE (PB-246), RESET (PB-245), and ESD RESET (PB-62B) push buttons.**
    The HS-231A button on the AGO screen should be red, selecting the HS-231A button on the screen brings up another red HS-231

button, and the EMERGENCY SHUTDOWN alarm light on the BMS panel should be off.

12. **On the DCS, verify that the AGO SHUTDOWN button (HS-231A) does not have a shutdown signal. Reset the AGO shutdown if needed.**
    Open the AGO SHUTDOWN button, if HS-231A is green it needs to be reset. If HS-231A is red, no shutdown signal is being sent to the AGO.

13. **Verify the DCS did the pre-mode shift actions for IDLE MODE.**
    a) HV-240 is closing. This takes 30 minutes to close, so do not wait until it is closed; continue this procedure.
    b) XV-103A and XV-103B are closed to isolate natural gas to unit.
    c) XV-820A and XV-820B are closed to isolate digester gas supply.
    d) XV-191, XV-280, XV-282 and XV-284 closed isolate purge and bleed nitrogen.
    e) XV-247B and XV-260 closed and XV-247A and XV-262 open.
    f) Cathode air blower (HS-224) is off with XV-241A closed.
    g) Preconverter Heater control (XS-195) is off. (If an immediate restart is expected, enable the heater. This will minimize heat loss.)
    h) Digester Gas Compressor (HS-800A) is off.
    i) TC-120 is in manual and is equal to – 5.
    j) On the water treatment system push "WTS ALARM RESET" button to reset the UA-406 alarm and verify Water Treatment System Permitted (HY-404).
    k) On the EBOP screen, verify PCS OP MODE Target is GRID .
    l) Verify XV-290 is shut.

Note to reviewer Was the following text deleted.

14. **Verify the plant is in IDLE mode.**
    The box for IDLE will turn green when in the IDLE mode.

15. **If needed change out nitrogen six-packs and put nitrogen bottles in service at this time.**
    This can be done in parallel with the continuing startup procedure.

16. **Check that each anode cover gas bottle pressure is greater than 1,500 psig. Change out bottles as needed.**
    Change any bottles that are less than 1,500 psig. This can be done in parallel with the start up procedure.

17. **Do a plant startup using one of the following procedures:**
    a) KCPP Rapid Restart (TI-320A >500°F). "Rapid Restart Procedure" on page 6-48
    b) KCPP Hot Restart (TI-320A 150°F to 500°F). "KCPP Hot Restart Procedure" on page 6-46
    c) KCPP Start Up to Hot Standby (TI-320A <150°F). "KCPP Startup to Hot Standby (NG)" on page 6-14. This procedure has put the plant Idle mode so there is no need to do that portion of the startup procedure again.

Note: Enter the procedure above at the point you need to start the plant.

Required screen prints table

H/U to 150°F

- KC Overview
- Plant Settings
- KC Start Up
- KC Fuel Cell Stack Piping
- Alarms List
- Misc. Parameters
- Any screens with alarms/warnings in that are pertinent to operating mode.
- Excel Spread Sheet Real Time Print (if available)

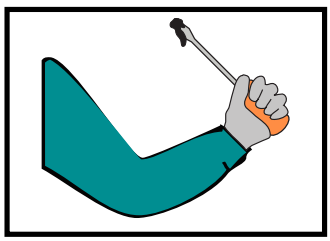
H/U to Hot Standby and Cooldown

- KC Overview
- Plant Settings
- KC AGO
- KC AGO FG
- KC Heat Recovery Unit
- KC Fuel Cell Stack Piping
- Air to Fuel
- KC Cell Temperatures
- KC Cell Voltages
- Misc. Parameters
- Alarms List
- Any screens with alarms/warnings in that are pertinent to operating mode.
- Excel Spread Sheet Real Time Print (if available)
- ADG System Overview (on ADG only)

At Power

- KC Overview
- Plant Settings
- EBOP
- KC AGO
- KC AGO FG
- KC Heat Recovery Unit
- KC Fuel Cell Stack Piping
- Air to Fuel
- Power to Fuel
- KC Cell Temperatures
- KC Cell Voltages
- KC Voltage Deviation Monitor
- Misc. Parameters
- Alarms List
- Any screens with alarms/warnings in that are pertinent to operating mode.
- Excel Spread Sheet Real Time Print (if available)
- ADG System Overview (on ADG only)

Proprietary information— Not Available for Publication.	



6.9 KCPP Hot Restart Procedure

This procedure is used once the plant is in IDLE. The fuel cell stack module must be above 150°F on TI-240, and less than 500°F on TI-320A. The nitrogen system must be at pressure, the water treatment and instrument air systems must be ready, and all alarms must be cleared from the fire panel. When this procedure is finished, you enter the plant heatup sequence at HEATUP-1 NG.

Initial conditions

- The plant has been placed in an idle condition using the trip recovery procedure or the plant startup to Hot Standby procedure.
- Cell temperature is above 150°F on TI-240 and less than 500°F on TI-320A otherwise must use plant startup to Hot Standby procedure.
- The Plant Target Mode is IDLE and the Actual Plant Mode is IDLE.

Prepare for Hot Restart

1. **Verify the Plant Target Mode is IDLE and the Actual Plant Mode is IDLE. Before starting, check the auxiliary systems are operating.**
   Check the DCS screen or locally if needed and verify these systems are clear of alarm and running normally:
   a) Check the nitrogen system pressure, replace the nitrogen six packs if needed.
   b) Check the water treatment system
   c) Check the instrument air system
   d) Check the safety and fire protection system.
2. **If maintenance has been done on any system, verify the following:**
   a) No equipment has been left disassembled, and all electrical and control systems are restored. The valve lineup is correct, adjust the valves as needed.
   b) Lockout tag outs have been removed and the affected equipment has been re-tested, if possible.
3. **On the King County Operational Mode Control screen verify the PLANT STARTUP OPTION for auto STARTUP is set to manual.**
4. **On the King County Plant Settings screen verify all settings match the plant settings table.**

Shifting the plant to Hot Restart

NOTE: If you intend to do a Rapid Restart, go to the rapid restart procedure. "Rapid Restart Procedure" on page 6-48

1. **On the King County Operational Mode Control screen select HOT RESTART**
   The box for HOT RESTART will turn yellow and the mode transition checklist will appear for HOT RESTART MODE.
2. **The Plant Target Mode is HOT RESTART and the Actual Plant Mode is IDLE.**
3. **Verify HOT RESTART mode transition checklist items are complete.**
   All blue and black text should be followed by a green check mark.

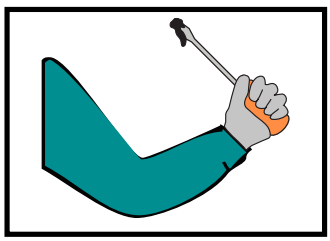
   If text is blue with a red X, the operator must verify the step is complete and then click on the blue text to change the red X to a green check mark.

   If a red X is next to black text, when the DCS gets a signal that this step is complete it will change the red X to a green check mark. DCS may not automatically do this step so the operator may need to do this step.
4. **Verify the plant is in Hot Restart mode.**
   The box for HOT RESTART will turn green when in the HOT RESTART mode.
5. **Continue plant startup using Heatup-2 in the Startup to Hot Standby procedure.**

NOTE: At this point the plant must be restarted using Plant Startup to Hot Standby procedure starting with Changing from Heatup-1 or Hot Restart to Heatup-2 NG. The DCS will not perform automatic actions unless starting at this point.

Startup to Hot standby plant settings

Proprietary information— Not Available for Publication.	



6.10 Rapid Restart Procedure

For this procedure the plant must be in Idle, the fuel cell stack "best temperature" is greater than 500°F as determined by the FCE operator. The fuel preparation and water treatment system are lined up and running, and the instrument air system is running. If digester gas is to be used the digester gas preparations system is also up and running. Anode cover gas is used if fuel had been sent to the system before the shutdown.

Initial conditions

- The plant has been placed in an idle condition by using the trip recovery procedure or the plant startup to hot standby procedure.
- The plant target mode is IDLE and the actual plant mode is IDLE.
- If "best temperature" is more than 500°F then you can use a rapid restart. If less than 500°F then you must use the plant startup to hot standby procedure.

  Determine the cell temperature by getting the TI-320 median pre-trip temperature. This temperature is the referred to as the "best temperature" and is recorded in the plant logs for future reference.
- Natural gas preparation and water treatment systems are lined-up, operating, and ready to supply water and gas. Reset UA-406.
- TY-238B Rapid Restart heatup rate is set to 600°F (or as directed by the FCE supervisor).
- TY-244 Rapid Restart heatup rate is set to 250 °F (or as directed by the FCE supervisor).

Potential problems

- If the actual value of TC-238 exceeds the initial ramp end value (best temperature minus 50 °F), change ramp end value to the Best Temperature.
- The use of anode cover gas for the Rapid Restart is needed if fuel was enabled before to trip. When given the option to use anode cover gas, select YES.

CAUTION

Do not allow cover gas to flow for more than 30 minutes without the AGO blower running. If the AGO blower cannot be starte witnin this 30-minute limit, shut down the covergas. Do NOT attpemt to restart until the blower is ready to start, troubleshoot, clear and reset any blower faults.

- Once started, the water and gas will disable if one of the following five things happen:
  - The preconverter catalyst bed temperature (TI-142) is <500°F.
  - The oxidizer catalyst bed temperature is at or <850°F on TC-244, which is the average of TI-244A/B/C temperatures.
  - The HRU stack exhaust temperature (TI-125) is <450°F.
  - XV-262 is closed, because this valve must be open to enable fuel flow. If SV-262 closes the plant will shutdown on a ESD.
  - TI-331 is below the low low set point of 300°F.
- HIC-240 will close slowly (30 minutes) after TC-238 >TI-240.

Rapid Restart

1. **On the King County Operational Mode Control screen select HOT RESTART.**

   The box for HOT RESTART will turn yellow and the mode transition checklist will appear for HOT RESTART MODE.

2. **Verify the Plant Target Mode is HOT RESTART and the Actual Plant Mode is IDLE.**

3. **Verify HOT RESTART mode transition checklist items are complete.**
4. **Select RAPID RESTART on the mode transition checklist.**
5. **Enter the BEST TEMPERATURE already determined with FCE management.**
   a) Type in the best temperature and press ENTER.
   b) When ENTER is pressed a confirmation is displayed showing the temperature that was entered. If the temperature entered is correct select YES.
6. **The next popup will ask to select whether to use Anode Cover Gas or not. Do NOT select either button at this time. Go to the procedure you intend to use.**
   Go to the Rapid Restart with anode cover gas procedure (next) if you intend to select YES otherwise go to the Rapid Restart without anode cover gas procedure. "Rapid Restart without anode cover gas" on page 6-51

Rapid Restart with anode cover gas

1. **Put one anode cover gas bottle in service.**
   a) (HV-290 or HV-291 open, not both, and open both bottle isolations), verify that PI-290 pressure is greater than 1500 psig.
   b) Remove alarm suppression from PI-290.
2. **Once everyone has been briefed and are ready for plant start, select YES for Anode Cover Gas.**

CAUTION

Do not allow cover gas to flow for more than 30 minutes without the AGO blower running. If the AGO blower cannot be starte witnin this 30-minute limit, shut down the covergas. Do NOT attpemt to restart until the blower is ready to start, troubleshoot, clear and reset any blower faults.

3. **Verify the following has happened.**
   a) XV-247A closes
   b) XV-262 closes
   c) XV-247B remains closed
   d) XV-260 remains closed.
4. **Verify that XV-280 and XV-290 are open.**
5. **If needed, adjust HV-293 to establish a greater than 1 inch W.C. differential pressure on PDI-257.**
   This only needs to be set if it has not been previously set or is no longer able to maintain 1 inch W.C. differential pressure on PDI-257.
6. **Continously monitor PDI-257 (PI-252 to PI 309 differential pressure) through out the Rapid Restart. Adjust HV-293 as needed so that the anode cover gas pressure is greater than 1 inch W.C.**
7. **Once the differential pressure is above 1 inch W.C. on PDI-257 for 60 seconds, the plant will immediately startup in Heatup 2. The mode transition checklist for Heat up 2 NG will pop up.**
   a) Verify HEAT UP 2 NG mode transition checklist items happen.
   b) Verify all the rest of the mode transition checklists as they pop up.

CAUTION

Fuel enable shoud not be permitted with anode outlet valve XV-262 closed. Verify the valve is open before fuel is enabled.

8. **Verify Auto Startup is in AUTO.**
9. **Verify XV-241A opens.**
10. **Start the AGO blower manually if it does not start automatically.**
11. **Verify PC-222 is in auto at 28 inches W.C. and FC-210 is in auto at 900 scfm.**
12. **Verify HV-240 is open.**
    If HV-240 is,80% open during Rapid Restart for >20 seconds an emergency shutdown (ESD) will occur.
13. **Once PDAL-233 resets (primary air flow pressure switch across FC-230), start the AGO pilot as follows (on the burner management panel):**
    a) Press the SYSTEM STOP/RESET push-button.
    b) Verify the LIMITS SATISFIED light is lit.

c) Press the SYSTEM LOCAL START pushbutton.

d) Verify the system responded as follows (locally and on the DCS):

1) Purge light came on (local only).

2) System purged for 2 minutes.

3) Once the purge has finished, verify pilot gas valves XV-203 and XV-205 opened and pilot air valve XV-260 opened.

4) Within 10 seconds the pilot should light should light, check UV flame scanner BE-233 indicates lightoff.

NOTE: f the pilot fails to light and FC-210 starts to ramp up to 3,500 scfm, take manual control of FC0210. Set the output to zero (0). When the valve closes, return the controller to AUTO with a set point of 900 scfm.

When the pilot lights, FC-210 must be put into AUTO and the set point moved back to 900 scfm.

If the pilot fails to light three times, place the plant in SHUTDOWN. Do NOT attempt a restart until the pilot system is working, troubleshoot, correct and clear and pilot system alarms.

14. Once the pilot is lit, verify the AGO main burner isolation valves XV-212 and XV-214 opened and the main burner lit.

Shortly after main burner is lit the pilot isolation valves XV-203 and XV-205 should close.

15. Verify the following:

a) FC-210 resets to 900 scfm in AUTO

NOTE: FC-210 is held at 900 scfm until TC-238 PV exceeds BEST TEMPERATURE –150°F. Then FC-210 will ramp up using a set point of 2000 scfm.

b) TY-238 is in cascade (CAS) with a ramp rate set to 600°F.

c) TY-238 end value is set to 50°F below the BEST TEMPERATURE that was entered.

d) TY-244C ramp is disabled and TV-245 remains closed.

e) Verify that the plant goes into the next heat up mode as temperature requirements for each condition are met.

f) Track On/Track Off as necessary.

g) PDI-257 (PI-252 to PI-309 differential pressure) remains greater than 1 inch W.C. differential pressure. As long as anode cover gas is in service, adjust HV-293 as needed to keep the pressure at PDI-257 greater than 1 inch W.C.

16. Verify the following conditions are met to be able to start water and fuel flow:

a) Preconverter catalyst bed temperature (TI-142) is >600°F.

b) Oxidizer catalyst bed temperature is ≥1,000°F on TC-244, which is the average temperature of TC-244 A/B/C.

c) HRU stack exhaust temperature (TI-125) is >500°F.

d) XV-262 is open

e) TI-331 is above 300°F.

17. When the above conditions met, verify anode fuel and water flow is has started by checking the following:

a) XV-247A and XV-262 is open.

b) FV-131 is open to start water flow, followed closely by FV-117 opening to start fuel flow. Both controllers are in cascade, with a steam-to-carbon ratio of 8:1. (FC-131—water at about 80 scfm and FC-117—fuel at a minimum of 10 scfm).

c) Verify XV-280 and XV-290 are closed. (Should close about 10 seconds after fuel and water start.)

18. Verify FC-210 set point is 3500 scfm and flow is increasing.

19. As the startup progresses, verify TC-238 ramp end value is reset to 50°F below the best temperature for each heatup mode, unless TC-238 is greater than the set point then end value is BEST TEMPERATURE.

NOTE: RAPID RESTART ends when these three conditions are met:

TC-238 is greater than or equal to the BEST TEMPERATURE entered for RAPID RESTART.

FC-210 is greater than or equal to 3400 scfm.

The main AGO burner is lit (BE-243 is on).

20. If the RAPID RESTART ends and TY-238B ramp end value has not been changed to BEST TEMPERATURE, change it now.

a) Allow the temperature to stabilize, and continuously monitor TC-238 to prevent the temperature from overshooting or undershooting a lot.

b) Continuously monitor TI-246, this will be the first indication of what TC-238 will do.

c) Continue to monitor TC-238, when TC-238 gets to the new TY-238B ramp end value (provided FC-210 is greater than or equal to 3,400 scfm, and the main AGO burner is lit) RAPID RESTART should end.

21. Once RAPID RESTART has finished, verify the following:

a) HV-240 is closed (should close when TC-238 is greater than TI-240 and both BAL-233 and BAL-243 are on). Verify proper response; closes slowly over 30 minutes.

b) TY-238B ramp rate has been reset to the appropriate heat up mode ramp rate.

c) Anode fuel and water are enabled because TC-244 is > 1,000°F. If not do the following:

1) TRACK ON then TRACK OFF TY-244C to prevent TC-238 from cooling excessively once FV-245 has opened.

2) Verify TC-245 changes back to cascade and TY-244C begins to ramp.

3) Allow catalyst to heat up to 1,000°F at 250°F/HR.

4) Monitor that fuel and water are enabled once the catalyst temperature is > 1,000°F, TC-238 is > 700°F, TI-125 is > 500°F and TI-142 is > 600°F.

22. Verify FC-210 set point is 3,500 scfm and flow is increasing.

23. Once the catalyst heat up is finished, verify that TC-244 is greater than 1,000°F, and that the TY-244C ramp values are returned to the values needed for heat up mode, and that TC-245 is in the mode required on the TC-245 PID matrix.

24. Verify the anode fuel and water flow is established and anode cover gas is off.

a) XV-247A and XV-262 is open.

b) FV-131 is open to start water flow, followed closely by FV-117 opening to start fuel flow. Both controllers are in cascade, with a steam-to-carbon ratio of 8:1. (FC-131—water at about 80 scfm and FC-117—fuel at a minimum of 10 scfm).

c) If fuel and water have been on for 10 seconds, verify XV-280 and XV-290 are closed.

25. Contact FCE management for further direction.

26. Isolate the anode cover gas and replace bottle if the pressure is less than 1,500 psi.

Rapid Restart without anode cover gas

If anode fuel gas was not flowing when the plant shut down there is no need for anode cover gas.

1. Once everyone has been briefed and are ready for Rapid Restart, select NO for Anode Cover Gas.
Once the selection is confirmed, the startup will proceed.

2. The plant startup begins in Heatup 2. The mode transition checklist FOR 2 NG will pop up.

3. Verify Auto Startup is in AUTO.

4. Verify XV-241A opens and the blower starts.

5. Verify HV-240 is open.
If HV240 is less than 80% open during Rapid Restart for more than 20 seconds an emergency shutdown (ESD) will occur.

6. Verify PC-222 is in auto at 28 inches W.C. and FC-210 is in auto at 900 scfm.

7. Once PDAL-233 resets (the primary air flow pressure switch across FC-230), start the AGO pilot.
On burner management panel:

a) Press the SYSTEM STOP/RESET push-button.

b) Verify the LIMITS SATISFIED light is lit.

c) Press the SYSTEM LOCAL START push-button.

d) Verify the system responds as follows (locally and on the DCS):

1) Purge light is lit (local only).

2) The system is purged for 2 minutes.

3) After the purge is complete, pilot gas valves XV-203 and XV-205 are open and pilot air valve XV-260 is open.

4) Within 10 seconds, the pilot should light. (UV flame scanner BE-233 light is on).

8. Verify that once the pilot is lit, the main AGO burner valves XV-212 and XV-214 open and the main burner starts.

Shortly after main burner starts the pilot isolation valves XV-203 and XV-205 should close.

9. Verify the following:

a) FC-210 remains at 900 scfm and is in AUTO. (When TC-238 PV exceeds BEST TEMPERATURE –150°F, the set point on FC-210 will change to 3,500 scfm).

b) TY-238 ramp rate is set to 600°F.

c) TY-238 end value is set to 50°F below the BEST TEMPERATURE entered.

d) TY-244C ramp is paused and TV-245 is closed.

e) Track on/Track off, as necessary.

f) Verify plant goes into the next heat up mode as the temperature requirements for each condition are met.

10. As the startup continues, verify TC-238 ramp end value is reset to 50°F below the BEST TEMPERATURE for each heatup mode unless TC-238 is greater than the set point, then the end value is the BEST TEMPERATURE.

NOTE: RAPID RESTART ends when these three conditions are met:

TC-238 is greater than or equal to the BEST TEMPERATURE entered for RAPID RESTART.

FC-210 is greater than or equal to 3,400 scfm.

a) The main AGO burner is lit (BE-243 is on).

11. If the RAPID RESTART ends and TY-238B ramp end value has not been changed to BEST TEMPERATURE, change it now.

a) Allow the temperature to stabilize, and continuously monitor TC-238 to prevent the temperature from overshooting or undershooting a lot.

b) Continuously monitor TI-246, this will be the first indication of what TC-238 will do.

c) Continue to monitor TC-238, when TC-238 gets to the new TY-238B ramp end value (provided FC-210 ≥ 3400 scfm, and the main AGO burner is lit) Rapid Restart should end.

12. Once Rapid Restart has finished, verify the following:

a) HV-240 is closed (should close when TC-238 is > TI-240, FC-210 is >95% of set point, Rapid Restart is over, and both BAL-233 and BAL-243 are on).

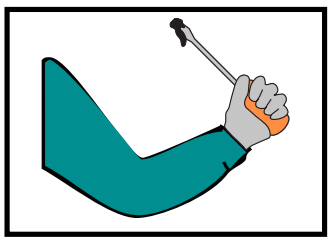
b) TY-238B ramp rate has been reset to the appropriate heat up mode ramp rate.

c) TY-244C ramp values are returned to the values required by the heat up mode.

d) TC-245 is in the required mode per the TC-245 PID matrix and once the ramp is complete the end value is 1,010.

13. Contact FCE management for further direction.

Reference



6.11 KCPP Shutdown Procedure

The plant can be shutdown from any allowed heat up (HU) mode or from Hot Standby. The Plant Target Mode and the Actual Plant Mode must be the same to proceed to a cool down (CD) mode. This is for a controlled shutdown, not a shutdown started because of an alarm. To prevent stressing the fuel cell stack, the cooldown like the heatup should be orderly. The cooldown setting that will be selected is based on the cathode inlet temperature and which heatup mode the system was in at the time of the shutdown. A full cooldown progresses through cooldown 1 through 3 and finishes when the plant enters IDLE.

Plant shutdown

A cool down (CD) can be started from any of the plant modes listed below. Select the appropriate cool down procedure based on current plant conditions.

- Hot Standby to Cooldown-1 NG/ DG (final DC1 temperature is 955°F).
- Heatup-4 NG/DG to Cooldown-1 NG/DG (final DC1 temperature is 955°F).
- Heatup-3 NG/DG to Cooldown-2 NG/DG (final DC2 temperature is 875°F).
- Heatup-2 NG/DG to Cooldown-3 NG/DG. (final DC3 temperature is 280°F).(In cool down 3, XV-191 will open when TI-142 is <500°F, or TC-120 is <550°F, or TI-320 MED is <650°F).

Cooling down from Hot Standby /Heatup-4 to Cooldown 1 NG/DG

The cathode inlet temperature is >990°F on TC-238. The plant was in Hot Standby/Heatup-4 NG/DG.

1. **The plant is in Hot Standby/Heatup-4 NG/DG, and the Plant Target Mode and the Actual Plant Mode is HOT STANDBY or HEATUP-4 NG.**
2. **Ensure the following plant conditions are met.**
   a) Water treatment system (HY-404) is PERMITTED.
   b) HV-240 is closed (HIC-240 set at 0%).
   c) XV-191, XV-280, XV-282, XV-284 are closed.
   d) FC-210 is in AUTO at 3,500 scfm.
   e) Verify the Heatup/Cooldown temp ramp rates for all modes except HU3 and CD2 are set at 15°F/hr.
   f) AGO is operating normally for the plant condition.
3. **On the King County operation mode control screen select COOL DOWN-1 NG/DG.**
4. **Verify the mode transition checklist items are completed.**
   When the plant is in COOL DOWN-1 the box for COOL DOWN-1 will turn green.

   All blue and black text should be followed by a green check mark.

   If text is blue with a red X, the operator must verify the step is complete and then click on the blue text to change the red X to a green check mark.

   If a red X is next to black text, when the DCS gets a signal that this step is complete it will change the red X to a green check mark. DCS may not automatically do this step so the operator may need to do this step.
5. **Verify the DCS did the following:**
   a) Preconverter jacket heater is off (may already be off if starting from hot standby).
   b) If TC-244 is <1,000°F verify:
      1) TY-244C started to ramp to TC-244 which is in AUTO at >1,000°F.
      2) TC-245 is in CAS (cascade).
      3) TY-238B is held until TC-244 is above 1,000°F.
   c) If TC-244 is >1,000°F verify:
      1) TC-244 is in AUTO at 1,010°F.

2) TC-245 is in cascade.

d) TC-238 is in cascade.

e) TC-243 is in manual with a set point of 1.0.

f) FC-117 is in cascade.

g) FC-131 is in cascade.

h) FC-208 is in cascade.

i) FC-210 is in auto with a set point of 3,500 scfm.

j) FC-230 is in cascade.

6. Verify actual plant cool down rate is 15°F/hr.

7. When Cooldown 1 is finished the plant will automatically change into COOLDOWN 2.
An alarm will sound when the Cooldown 1 mode is complete.

Cooling down from Cooldown-1or from Heatup-3 to Cooldown-2

The cathode inlet temperature is 990°F to 880°F on TC-238.

1. If the plant was in Cooldown-1, verify the following the DCS actions.

a) TY-238B ramp end value is set to 875°F and the ramp rate is 12°F/hr.

b) Verify TC-244 >1,000°F and TC-245 is in cascade.

c) Verify actual cooldown rate is 12°F/hr.

2. If the plant was in Heatup-3, then do the following:

a) Verify the plant is in HEATUP-3.

b) Verify heatup/cooldown temperature ramp rates for HU3 and CD2 are set at 12°F/hr.

c) On the King County Operation Control screen select COOL DOWN-2 NG/DG. (When the plant is in COOL DOWN-2 the box for COOL DOWN-2 will turn green).

d) Verify mode transition checklist items are complete. Once the mode shift is complete the box for COOL DOWN-2 NG/DG will turn green.

All blue and black text should be followed by a green check mark.

If text is blue with a red X, the operator must verify the step is complete and then click on the blue text to change the red X to a green check mark.

If a red X is next to black text, when the DCS gets a signal that this step is complete it will change the red X to a green check mark. DCS may not automatically do this step so the operator may need to do this step.

e) Verify the DCS did the following:

1) Preconverter jacket heater is off.

2) If TC-244 is <1,000°F verify:

TY-244C begins to ramp to TC-244 to >1,000°F in AUTO.

TC-245 is in CAS (cascade).

TY-238B is held until TC-244 is above 1,000°F.

3) If TC-244 is >1,000°F verify:

TC-244 into AUTO at 1,010°F.

TC-245 is in cascade.

4) TC-238 is in cascade with ramp end value of 875°F and ramp rate of 12°F/HR.

5) TC-243 is in manual with a set point of 1.0.

6) FC-117 is in cascade.

7) FC-131 is in cascade.

8) FC-208 is in cascade.

9) FC-210 is in auto with a set point of 3,500 scfm.

10) FC-230 is in cascade.

f) Verify actual cool down rate of 12°F/hr.

3. When Cooldown 2 is done, the plant will automatically change into COOLDOWN 3.
An alarm will sound when the Cooldown 2 is complete.

Entering COOLDOWN3 will disable the anode fuel preparation and water systems.

Valve XV-191 will open and purge the fuel gas piping and anode module as soon as:

- TI-320 MED<650°F
- TI-120 <550°F
- Ti-142<500°F

Cooling down from Cooldown-2 or Heatup-2 to Cooldown-3

The cathode inlet temperature is <880°F on TC-238.

The anode fuel preparation and water systems are disabled when TI-320 MED is less than 650°F.

Valve XV-191 will open and purge the fuel gas piping and anode module as soon as:

- TI-320 MED<650°F
- TI-120 <550°F
- Ti-142<500°F

1. If plant was in COOLDOWN-2, then verify the following the DCS actions.

a) TY-238B end value is set to 280°F and ramp rate is 15°F/hr.

b) Verify TC-244 is >1,000°F and TC-245 is in cascade.

c) Verify TY-238B ramp rate is set to 15°F/hr.

d) Verify the actual cooldown rate is 15°F/hr.

2. If plant was in HEATUP-2, then do the following.

a) Verify the plant is in Heatup-2 mode.

b) Verify heatup/cooldown temperature ramp rates for all modes except HU3 and CD2 is set for 15°F/hr.

c) On the King County operation control mode screen select COOL DOWN-3 NG/DG. (When the plant is in Cool down-3 the box for COOL DOWN-3 will turn green).

d) Verify the mode transition checklist items are completed. Once the mode shift is finished the box for COOL DOWN-2 NG/DG will turn green.

All blue and black text should be followed by a green check mark.

If text is blue with a red X, the operator must verify the step is complete and then click on the blue text to change the red X to a green check mark.

If a red X is next to black text, when the DCS gets a signal that this step is complete it will change the red X to a green check mark. DCS may not automatically do this step so the operator may need to do this step.

e) Verify the DCS did the following:

1) Preconverter jacket heater is off.

2) If TC-244 is >1,000°F and water and fuel are enabled verify:

TC-244 is in AUTO at 1,010°F.

TC-245 is in CAS (cascade).

3) TC-238 is in cascade with a ramp end value of 280°F and a ramp rate of 15°F/hr.

4) TC-243 is in MAN (manual) with a set point of 1.0.

5) FC-117 is in cascade. (If fuel and water are still enabled).

6) FC-131 is in cascade. (If fuel and water are still enabled).

7) FC-208 is in cascade.

8) FC-210 is in AUTO with a set point of 3500 scfm.

9) FC-230 is in cascade.

f) If TC-120 or TI-320MED are greater than 650°F, or fuel and water are still enabled, verify the DCS did the following:

1) TY-238B is enabled, ramp is not paused, and ramp end value is set to 280°F. If not, find and correct the cause. (TY238B ramp may be held if TC-244 is <1,000°F and TC-238 is >700°F).

2) Verify TC-244 >1,000°F and TC-245 is in cascade. If not, find and correct the cause.

3) Verify TY-238B ramp rate is set to 15°F/hr.

4) Verify actual cooldown rate is 15°F/hr.

5) Verify that XV-282 (fast N2 purge valve) does not open on LOW N2 BLEED HEADER PRESSURE (PAL-190) after the ESD has occurred and TI-320A is >650°F.

g) If TC-120, TI-320MED or TI-142 are less than 650°F or fuel and water are not enabled verify the DCS did the following:

1) TY-238B is enabled, ramp is not paused, and ramp end value is 280°F. If not, find and correct the cause. (TY238B ramp may be held if TC-244 is <1000°F and TC-238 is >700°F).
2) TY-244C is enabled, ramp is not paused, ramp end value is set to 150°F and TC-244 is in cascade. If not, find and correct the cause.
3) Verify TY-238B ramp rate is set to 15°F/hr. and TY-244C ramp rate is set to 50°F/hr.
4) Verify the actual cooldown rate is 15°F/hr. for TC-238 and 50°F/hr. for TC-244.

3. Once TI-320MED is <650°F, TC-120 is <550°F, and TI-142 is <500°F (or if they were below these set points when Cooldown-3 began), verify the following.

a) Verify on the faceplate that gas valve (FC-117/FC-800) went to manual with an output of zero (0) and that the valve is closed. If gas is still flowing, put the valve in manual and close the valve (put the output at zero), because without enough water the preconverter catalyst will be damaged.

b) Verify on the faceplate that water valve (FC-131) went to manual with an output of zero (0) and that the valve is closed. If water is still flowing, manually close FV-131, because without enough gas flow preconverter catalyst will be damaged.

c) Valve XV-191 opened to purge the fuel system. It will close once the low-pressure alarm (PAL-189), registers for the low-pressure side of the fast purge nitrogen system.

d) Close MV-1063, MV-8064, and MV-4042 to isolate the fuel (NG/DG) and water flow.

e) Open the anode and fuel line heat trace breakers.

f) About 20 minutes after TI-320MED reaches 650°F (decreasing), verify that TY-244C is enabled, the ramp is not paused, the ramp end value is set to 150°F and TC-244 is in cascade. If not, find and correct the cause. Verify the ramp rate is set to 30°F/hr.

4. Once water and fuel have been stopped for 30 minutes, do the following:

a) Open and leave open the purgatory drain valves (MV-3005A and MV-3005B).

b) Monitor the purgatory zone temperatures TE-317 and TE-372 to be sure that the temperatures do not go above 302°F.

c) If these temperatures go above302°F, close the purgatory zone drain valves (MV-3005A and MV-3005B) and contact FCE stack module engineering for further guidance.

5. When TI-320MED temperature goes below 650°F there is a two-hour hold. Monitor the plant for this response.

6. Turn off the anode and fuel gas line heat traces by opening breakers CB-161F and CB-163A.

7. Continue to monitor the cooldown. When TC-238 is 305°F or less, and TI-240 is 286°F or less, verify the DCS did the following:

a) The AGO main burner is turned off. (The pilot may start).

b) The AGO blower is turned off.

c) Total airflow controller FC-210 has changed to manual with the output set to zero.

d) Primary airflow controller FC-230 has changed to manual with the output set to zero.

e) AGO outlet temperature controller TC-238 has changed to manual with the output set to zero.

8. Verify Cooldown 3 is complete; the fuel cell plant is effectively shutdown.

The plant will continue to cooldown naturally.

When AGO outlet temperature controller TC-238 reaches 305°F or less and TC-244 reaches 286°F or less Cooldown 3 is complete. An alarm will sound when the Cooldown 3 is complete, and the plant mode will change to IDLE.

9. Close both purgatory zone drain valves (MV-3005A and MV-3005B) before the stack (vessel) temperature reaches 200°F.

KCPP cool down below 286°F

This is a special operating procedure. Once the following conditions are met the startup heater and blower can be used to control the cooldown rate at 15°F/hr., if needed.

- Plant cool down is finished through Cool Down 3.
- TC-240 and TI-320A are less than 300°F (max temperature that can be circulated through the startup blower).
- Plant in IDLE.

1. Prepare to continue the cool down as follows:

a) On TY-216B, set the startup heater temperature ramp rate end value to the desired temperature.

b) On the HRU screen, verify TV-120A and B are closed. If not set TC-120 to –5 and they will close.

c) On the HRU screen, open HV-240 by taking HIC-240 to 100%.

d) Verify the temperature ramp for the startup skid (TY-216B) on the DCS is RAMP DISABLED.

2. Startup the startup heater and blower

a) Verify that the startup heater and blower skid and all temporary piping are properly installed per the startup skid installation procedure.

b) Verify that power and instrumentation cables are properly connected.

c) Open KC-MV-2039 and KC-MV-2040 then close MV-2042 (startup heater shell drain valve) and MV-2043 (startup blower casing drain valve).

d) Turn on power to startup skid receptacle (breaker CB-155D in the EBOP) and turn on the startup skid receptacle (the welding receptacle on the corner of the fuel prep skid, near the preconverter after filter).

e) Close the panel breaker for the startup heater and blower on the local control panel. Turn the SETUP/OFF/ON switch to ON.

f) Turn the startup blower motor switch to ON, if needed.

3. Start the cooldown.

a) Monitor TY-216B and TI-216. When TI-216 is about equal to cell temperature inlet (TC-238), close HV-240 by taking HIC-240 to 0%.

b) On TY-216B do a Track On/Track Off.

c) Enable the TY-216B ramp.

d) Monitor the cooldown rate. The heater should only operate as needed to prevent the cooldown rate from exceeding 15°F/HR.

4. Once cooldown is complete do the following:

a) Disable the temperature ramp for the startup skid (TY-216B).

b) Turn off the blower and heater at the local control panel by placing the startup blower motor switch to OFF.

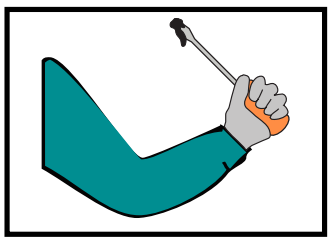
c) Close KC-MV-2039 and KC-MV-2040, and open MV-2042 (startup heater shell drain valve) and MV-2043 (startup blower casing drain valve).

d) Turn the SETUP/OFF/ON switch to OFF and open the breaker on the startup skid local control panel.

e) Turn off the power to the receptacle supplying the startup skid (welding receptacle on the corner of the fuel prep skid, near the preconverter after filter) and open Startup Skid breaker (Breaker 155D in EBOP).

f) Start of verify a nitrogen or dry/oil free air purge of the fuel cell, as needed.

Reference



6.12 Using the Startup Skid

The startup skid is used to preheat the fuel cell stack, it drives out moisture and warms the stack to about 250°F. The equipment is isolated before the system reaches 300°F. Air above 300°F circulated through the blower will damage it. When using the system, the heater is normally run in SET UP and the blower motor is normally turned to ON. The startup blower differential pressure and the heater pressure are monitored on local gauges.

Starting up the startup skid

1. **Reassign TY-216B to DCS Nodes as follows:**
   a) Open TY-216B in Control Studio Edit mode.
   b) Select ASSIGN TO NODE button from toolbar (half blue arrow) and select KCCTRL, and OK.
   c) Then SAVE and download (full blue arrow) this module.
2. **Verify that the startup heater and blower skid and all temporary piping are not damaged and the suction and discharge valves are open.**
3. **Verify the equipment is plugged in to the receptacle.**
4. **Verify applicable portions of KCPP Plant Pre-Startup Valve Lineup are complete.** See "Initial Valve Lineup Checklist" on page 6-104.
5. **Verify temperature ramp for startup skid (TY-216B) on DCS is ramp disabled.**
6. **Open KC-MV-2039 and KC-MV-2040 then shut valves MV-2042 (startup heater shell drain) and MV-2043 (startup blower casing drain).**
7. **Turn on power to the startup skid receptacle (breaker CB-155D in EBOP) and turn on the startup skid receptacle (welding receptacle on the corner of the fuel prep skid, near the preconverter after filter).**
8. **Close the panel breaker for the startup heater and blower on the local control panel. Place the SETUP/OFF/ON switch to ON.**
9. **When required, during the Plant Startup Procedure place the startup blower motor switch to ON.**
10. **The startup heater and blower are now ready for operation from the DCS.**

Note: If restarting the startup skid when it is already hot, there is a possibility of reaching the heater's high limit. If this occurs, the LIMIT RESET button must be pressed in order to continue operation of the startup skid.

Shutting down the startup skid

1. **When heat up is complete, disable the temperature ramp for the startup skid (TY-216B) if needed.**
2. **Place the heater's SETUP/OFF/ON switch to OFF and open the breaker on the startup skid local control panel.**
3. **Turn off the blower (MOTOR) at the local control panel.**
4. **Close valves KC-MV-2039 and KC-MV-2040, and open valves MV-2042 (startup heater shell drain) and MV-2043 (startup blower casing drain).**
5. **Turn off the receptacle supplying the startup skid (welding receptacle on the corner of the Fuel Prep skid, near the preconverter after filter) and open startup skid breaker (breaker 155D in EBOP).**
6. **Disconnect power and instrumentation cables.**
7. **Remove TY-216B from DCS Nodes as follows:**
   a) Open TY-216B in control studio in the EDIT mode.

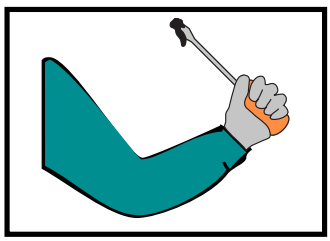
b) Select FILE and UNASSIGN FROM NODE

c) Select SAVE and close the module.

d) From DeltaV Explorer, select Expand KC_CTRL. Under ASSIGNED MODULES, find TY-216B.

e) Right click on TY-216B and select DOWN-LOAD → DELETE from controller.

Reference



6.13 Operating the Fuel Preparation System

To startup the fuel preparation system the lines must be filled with methane. When filling the lines with methane the vent valve must be opened so the methane can displace the trapped air inside the lines. Once you open this common vent valve methane will vent to the atmosphere. Verify there are no ignition sources, or sparking sources in the area, and that no un necessary people are in the area. All the panels in the water treatment skid must be in place. A piece of flexible tubing can be connected to the vent tubing to vent the methane to a safe location. The tubing must be rated for low pressure methane.

WARNING

The startup procedure vents methane to the atmosphere through the desulfurizer vent. Before venting the methane verify there are no people in the area and that there are no ignition sources.

Stopping the gas flow through a desulfurizer may allow pockets of concentrated highly volatile organic compound (VOC) to develop these hot spots can damage the carbon and the create a fire hazard. Once natural gas has been admitted to the desulfurizers, minimize the amount of time that flow is stopped.

Before starting the fuel prep system

Verify that both desulfurizers are out of service., there is no natural gas flow through the system, each desulfurizer has been purged with nitrogen, and the KCPP Plant Pre-Startup Valve Lineup has been completed. See See “Initial Valve Lineup Checklist” on page 6-104.

Starting the system

1. **Line up the desulfurizers.**
   Line up the desulfurizers to operate in one of the following ways.

   If you want A as lead, and B as guard then do the following:

   - Close MV-1021 (desulfurizer B inlet valve).
   - Open MV-1028 (desulfurizer A outlet valve).
   - Open MV-1036 (desulfurizer B product) valve.

   If you want B as lead, and A as guard then do the following:

   - Close MV-1020 (desulfurizer A inlet valve).
   - Open MV-1031 (desulfurizer B outlet valve).
   - Open MV-1033 (desulfurizer A product valve).

   If you want A as lead, and B isolated then do the following:

   - Close MV-1021 (desulfurizer B inlet valve).
   - Open MV-1033 (desulfurizer A product valve).

   If you want B as lead, and A isolated then do the following:

   - Close MV-1020 (desulfurizer A inlet valve).
   - Open MV-1036 (desulfurizer B product valve).

2. **Verify from the DCS that XV-103A and XV-103B are open (natural gas isolation valves).**

WARNING

Purging with natural gas vents methane to the atmosphere through the desulfurizer vent. Before venting the methane verify there are no people in the area and that there are no ignition sources.

3. **Purge the desulfurizers with natural gas (NG):**

   a) Open the desulfurizer vent valve:
      - If lined up for B lead, A guard, open MV-1018 (vent valve for desulfurizer A).
      - If lined up for A lead, B guard, open MV-1023 (vent valve for desulfurizer B).
      - If lined up for A lead, B isolated, open MV-1018 (vent valve for desulfurizer A).
      - If lined up for B lead, A isolated, open MV-1023 (vent valve for desulfurizer B).

   b) Open MV-1060 (combined desulfurizer vent isolation valve).

   c) Open MV-1002 (NG supply isolation valve).

   d) Start the NG purge of the desulfurizers by slowly opening MV-1005 (NG supply to fuel prep skid valve).

   e) During the purge, check pressure gauge PI-102 is at 15 psig. PCV-101 (NG pressure control valve) should maintain 15 psig.

   f) Check for flow by listening for flow noise through the vent(s) and check the desulfurizer pressure gauges as applicable. Desulfurizer A pressure gauge (PI-107) and/or desulfurizer B pressure gauge (PI-110) should be near zero.

   g) After purging for at least one minute, shut MV-1018 (desulfurizer A vent valve) and MV-1023 (desulfurizer B vent valve) as applicable.

   h) Close MV-1060 (combined desulfurizer vent isolation valve).

WARNING

This next step vents methane to the atmosphere. Vent the methane as slowly as practical to cut down on the possibility of having an explosive concentration accumulate in the area.

WARNING

Vent the methane to the open atmosphere and away from any flames or equipment capable of generating sparks. If necessary attach a tubing or hose to the vent and vent the methane to some safe location away from the AGO skid.

4. **Place a LEL detector at the vent line on the pilot gas strainer valve.**
   To be able to light AGO pilot, the natural gas desulfurized (NGD) line must be filled with methane. To fill the line, place an LEL detector near the vent from pilot gas strainer valve.

5. **Open the vent valve MV-2036 until methane is detected at the LEL detector, then close the vent valve.**

6. **Verify the area is free of methane using an LEL detector**

7. **When the area is free of methane start the natural gas heater.**
   Turn the natural gas heater controller panel breaker (100-HE-101) to ON, and turn the ON/OFF/SETUP switch to ON. Verify that the heater is set between 65° and 70°F.

Shutting down the system

WARNING

Stopping the gas flow through a desulfurizer may allow pockets of concentrated highly volatile organic compound (VOC) to develop. These hot spots can damage the carbon and create a fire hazard. Once natural gas has entered the desulfurizers, minimize the amount of time that gas flow is stopped.

1. **Verify the AGO is off and there is no natural gas flow.**
   Before you start to shut down the fuel preparation system, the anode gas oxidizer (AGO) must be is shut down and the natural gas flow through the system stopped.

2. **Turn off the natural gas heater.**
   Turn the ON/OFF/SETUP switch on the natural gas heater (100-HE-101) control

panel to SETUP (Turning the switch to OFF and the panel's circuit breaker to OFF will disable the NG temperature indication (TI-110) at the DCS since this is transmitted from the panel's 988 controller.)

3. **Purge all or part of the system with nitrogen as necessary.**

Purging the desulfurizers with nitrogen

Perform one of the following:

- **Purge both desulfurizers with nitrogen.**

  a) Close MV-1002 (NG supply isolation) and MV-1005 (NG supply to fuel prep skid valve).

  b) Connect a nitrogen purge supply to MV-1013 (NG heater vent valve) with a pressure regulator and flow meter capable of measuring 5 scfm flow.

  c) Open MV-1018 (desulfurizer A vent valve) and MV-1023 (desulfurizer B vent valve).

  d) Slowly open MV-1060 (combined desulfurizer vent isolation valve) to reduce pressure in the desulfurizers and piping. Wait until venting flow stops before continuing.

  e) Close (or verify closed):
     - MV-1028 (desulfurizer A outlet valve).
     - MV-1031 (desulfurizer B outlet valve).
     - MV-1033 (desulfurizer A product valve).
     - MV-1036 (desulfurizer B product valve).
     - Open (or verify open):
     - MV-1020 (desulfurizer A inlet valve)
     - MV-1021 (desulfurizer B inlet valve)

     (The desulfurizers are now lined up for parallel flow.)

  f) Purge for 2 or 4 hours at 5 scfm.

     Open MV-1013 and perform a 2-hour nitrogen purge at 5 scfm. (Purge for 4 hours at 5 scfm if the system piping of equipment will be opened for maintenance or other reasons.)

  g) After finishing the nitrogen purge, close MV-1013, MV-1018, MV-1023 and MV-1060.

- **Purge the entire natural gas (NG) and natural gas desulfurized (NGD) system with nitrogen (N2):**

  a) Close MV-1002 (NG supply isolation valve).

  b) Open (check open) MV-1005 (NG supply to fuel prep skid valve), XV-103A, and XV-103B (natural gas stop valves).

  c) Connect a nitrogen bottle to MV-1001 (NG supply sample valve). Use a pressure regulator and flow meter capable of measuring 5 scfm flow.

  d) Open MV-1018 (desulfurizer A vent valve) and MV-1023 (desulfurizer B vent valve).

  e) Slowly open MV-1060 (combined desulfurizer vent isolation valve) to reduce pressure in the desulfurizers and piping. Wait until venting flow stops before continuing.

  f) Close (or verify closed):
     - MV-1028 (desulfurizer A outlet valve).
     - MV-1031 (desulfurizer B outlet valve).
     - MV-1033 (desulfurizer A product valve).
     - MV-1036 (desulfurizer B product valve).

  g) Open (or verify open):
     - MV-1020 (desulfurizer A inlet valve)
     - MV-1021 (desulfurizer B inlet valve)

     (The desulfurizers are now lined up for parallel flow.)

  h) Open FV-117 to its 100% position from the DCS.

  i) Open MV-1063 (NGD isolation to FV-117 valve)

  j) Open XV-247B and shut XV-247A.

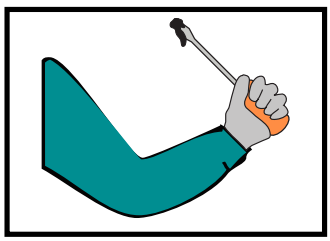
     (If operating these valves by hand wheel, first be sure the air is isolated to the actuator and the actuator's stopcock vent is open.)

k) Purge for 3 or 6 hours at 5 scfm.

Open MV-1001 and perform a 3-hour nitrogen purge at 5 scfm. (Purge for 6 hours at 5 scfm if the piping or equipment will be opened for maintenance or other reasons.)

l) After finishing the nitrogen purge, close MV-1001, MV-1018, MV-1023 and MV-1060.bv3

Reference



6.14 Changing Desulfurizer Lead and Guard Positions

The desulfurizers are normally run in series, with one desulfurizer in the lead and the other in guard. When a desulfurizer needs maintenance, the other desulfurizer is put in the lead position, and the vessel that needs maintenance, is taken out of service by purging it with nitrogen and isolating it. When it is put back in service, the vessel must be filled with methane to displace the nitrogen and air until methane can be detected on an LEL meter at the vent. The the desulfurizer is placed back in service in the guard position.

Changing the lead/guard position

This procedure is done when plant is operating with one desulfurizer in the lead position and the other in guard position and you want to switch lead/guard positions.

If A is lead and B is guard, and you want B as lead and A as guard

a) Open MV-1021 (desulfurizer B inlet valve).

b) Close MV-1028 (desulfurizer A outlet valve).

c) Open MV-1033 (desulfurizer A product valve).

d) Close MV-1036 (desulfurizer B product valve).

e) Open MV-1031 (desulfurizer B outlet valve).

f) Close MV-1020 (desulfurizer A inlet valve).

If B is lead and A is guard, and you want A as lead and B as guard

a) Open MV-1020 (desulfurizer A inlet valve).

b) Close MV-1031 (desulfurizer B outlet valve).

c) Open MV-1036 (desulfurizer B product valve).

d) Close MV-1033 (desulfurizer A product valve).

e) Open MV-1028 (desulfurizer A outlet valve).

f) Close MV-1021 (desulfurizer B inlet valve).

Running with one desulfurizer online

This procedure it done when the plant is operating with one desulfurizer in the lead position and the other in guard position and you want to isolate one desulfurizer because it has failed or needs maintenance.

Changing from A as lead and B as guard to B as lead and isolating A.

WARNING

This procedure vents methane to the atmosphere through the desulfurizer vent. Before venting the methane, verify there are no people in the area and that there are no ignition sources.

Stopping the gas flow through a desulfurizer may allow pockets of concentrated highly volatile organic compound (VOC) to develop. These hot spots can damage the carbon and create a fire hazard. Once natural gas has entered the desulfurizers, minimize the amount of time that flow is stopped before starting to purge the desulfurizer with nitrogen.

1. **Connect a nitrogen bottle to MV-1032 (desulfurizer N2 purge valve). Use a pressure regulator and flow meter capable of measuring 5 scfm flow.**

2. **Open MV-1021 (desulfurizer B inlet valve).**

3. **Isolate desulfurizer A.**

   a) Lock closed MV-1020 (desulfurizer A inlet valve).

   b) Lock closed MV-1028 (desulfurizer A outlet valve).

4. **Open MV-1060 (desulfurizer combined vent valve).**

5. **Slowly open MV-1018 (desulfurizer A vent valve) to reduce pressure in desulfurizer A.**
6. **Wait until venting flow stops before continuing.**
7. **Open MV-1029 (desulfurizer A purge valve).**
8. **Open MV-1032 (desulfurizer N2 purge valve) to begin the nitrogen purge on desulfurizer A.**
   Maintain the nitrogen purge for 50 minutes at 5 scfm. (Purge for 100 minutes at 5 scfm if this system will later be opened for maintenance or other reasons.)

NOTE: *In order to properly purge of the desulfurizer vessels, 5 scfm of nitrogen must be maintained for the whole 50-minute purge. This is equal to 2 vessel volumes. If, at any time during the purge, the flow drops below 5 scfm, then increase the purge time so that the vessel is purged for a total of 50 minutes at 5 scfm.*

WARNING

If the desulfurizer vessel is to be opened, sample the flow of gases from the desulfurizer vent using a portable LEL detector before finishing the nitrogen purge. Percent LEL should be below 5%. If not, continue with the nitrogen purge until percent LEL is less than 5%.

Nitrogen itself is not dangerous but it will displace the oxygen in a vessel, which can kill someone by asphyxiation. Isolate and remove the nitrogen supply bottle so that nitrogen cannot be accidentally be put in the desulfurizer vessel.

9. **Isolate and remove the nitrogen supply bottle.**
10. **If the carbon bed is to be removed now, leave the desulfurizer vented to atmosphere and continue to the procedure, *Replacing the carbon media in the desulfurizer*. Otherwise, close MV-1018 (desulfurizer A vent valve) and MV-1060 (desulfurizer combined vent valve).**

Changing from B lead, A guard to A lead, B isolated.

WARNING

This procedure vents methane to the atmosphere through the desulfurizer vent. Before venting the methane, verify there are no people in the area and that there are no ignition sources.

Stopping the gas flow through a desulfurizer may allow pockets of concentrated highly volatile organic compound (VOC) to develop. These hot spots can damage the carbon and create a fire hazard. Once natural gas has entered the desulfurizers, minimize the amount of time that flow is stopped before starting to purge the desulfurizer with nitrogen.

1. **Connect a nitrogen bottle to MV-1032 (desulfurizer N2 purge valve). Use a pressure regulator and flow meter capable of measuring 5 scfm flow.**
2. **Open MV-1020 (desulfurizer A inlet valve).**
3. **Isolate desulfurizer B.**
   a) Lock closed MV-1021 (desulfurizer B inlet valve).
   b) Lock closed MV-1031 (desulfurizer B outlet valve). Open MV-1060 (desulfurizer combined vent valve).
4. **Slowly open MV-1023 (desulfurizer B vent valve) to reduce pressure in desulfurizer B.**
5. **Wait until venting flow stops before continuing.**
6. **Open MV-1030 (desulfurizer B purge valve).**
7. **Open MV-1032 (desulfurizer N2 purge valve) and begin purging desulfurizer B.**
   Maintain the nitrogen purge for 50 minutes at 5 scfm. (Purge for 100 minutes at 5 scfm if this system will later be opened for maintenance or other reasons.)

NOTE *In order to properly purge of the desulfurizer vessels, 5 scfm of nitrogen must be maintained for the entire 50-minute purge. If, at any time during the purge, the flow drops below 5 scfm, then increase the*

purge time so that the vessel is purged for a total of 50 minutes at 5 scfm.

WARNING

If the desulfurizer vessel is to be opened, sample the flow of gases from the desulfurizer vent using a portable LEL detector before finishing the nitrogen purge. Percent LEL should be below 5%. If not, continue with the nitrogen purge until percent LEL is less than 5%.

Nitrogen itself is not dangerous but it will displace the oxygen in a vessel, which can kill someone by asphyxiation. Isolate and remove the nitrogen supply bottle so that nitrogen cannot be accidentally be put in the desulfurizer vessel.

8. **Isolate and remove the nitrogen supply bottle.**
9. **If the carbon bed is to be replaced now, leave the desulfurizer vented to atmosphere and continue to the procedure, *Replacing the carbon media in* the desulfurizer. Otherwise, shut MV-1023 (desulfurizer B vent valve) and MV-1060 (desulfurizer combined vent valve).**

Putting a desulfurizer back in service

Putting A back in service. In this procedure you will bring desulfurizer A, which was isolated, back on line in the guard position.

WARNING

This procedure vents methane to the atmosphere through the desulfurizer vent. Before venting the methane, verify there are no people in the area and that there are no ignition sources.

Stopping the gas flow through a desulfurizer may allow pockets of concentrated highly volatile organic compound (VOC) to develop. These hot spots can damage the carbon and create a fire hazard. Once natural gas has entered the desulfurizers, minimize the amount of time that flow is stopped before starting to purge the desulfurizer with nitrogen.

1. **If desulfurizer A was open for maintenance or other reasons, purge that desulfurizer with nitrogen.**
   See "Changing Desulfurizer Lead and Guard Positions" on page 6-66 or "Purging the Desulfurizer and Preconverter with Nitrogen" on page 6-70.
2. **Then purge the desulfurizer for 15 minutes with NGD as follows.**
   a) Set PCV-112 (NG flow control valve) to 8 scfm.
   b) Open MV 1034 (FCV-112 downstream isolation valve).
   c) Open MV-1029 (desulfurizer A purge valve).
   d) Slowly open MV-1035 (FCV-112 upstream isolation valve) to begin the NGD purge.
   e) Listen for flow noise through the vent to verify flow and check the desulfurizer A pressure (PI-107) is near zero. Purge the vessel for 15 minutes.
   f) Close MV-1018 (cold gas desulfurizer A vent valve) and MV-1060 (desulfurizer combined vent valve).
   g) When the pressure in desulfurizer A is about equal to the pressure in desulfurizer B, close MV-1035 (FCV-112 upstream isolation valve).
   h) Close MV 1034 (FCV-112 downstream isolation valve).
   i) Close MV-1029 (desulfurizer A purge valve).
   j) Open MV-1031 (desulfurizer B outlet valve).
   k) Open MV-1033 (desulfurizer A product valve).
   l) Close MV-1036 (desulfurizer B product valve).

Putting B back in service. In this procedure you will bring desulfurizer B, which was isolated, back on line in the guard position.

WARNING

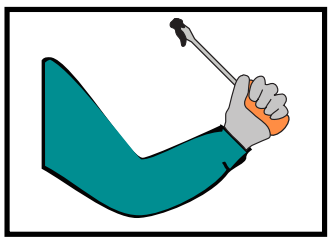
This procedure vents methane to the atmosphere through the desulfurizer vent. Before venting the methane, verify there are no people in the area and that there are no ignition sources.

Stopping the gas flow through a desulfurizer may allow pockets of concentrated highly volatile organic compound (VOC) to develop. These hot spots can damage the carbon and create a fire hazard. Once natural gas has entered the desulfurizers, minimize the amount of time that flow is stopped before starting to purge the desulfurizer with nitrogen.

1. **If desulfurizer B was open for maintenance or other reasons, purge that desulfurizer with nitrogen.**
   See "Changing Desulfurizer Lead and Guard Positions" on page 6-66 or "Purging the Desulfurizer and Preconverter with Nitrogen" on page 6-70.

2. **Then purge the desulfurizer with natural gas desulfurized (NGD) by doing the following:**
   a) Set PCV-112 (NG flow control valve) to 8 scfm.
   b) Open MV 1034 (FCV-112 downstream isolation valve).
   c) Open MV-1030 (desulfurizer B purge valve). Maintain the purge for 15 minutes (for 2 volumes).
   d) Slowly open MV-1035 (FCV-112 upstream isolation valve) to begin the NGD purge.
   e) Verify flow through the vent by observing flow noise and by observing desulfurizer B pressure (PI-110) near zero.
   f) Close MV-1023 (desulfurizer B vent valve) and MV-1060 (desulfurizer combined vent valve).
   g) When desulfurizer B pressure approximately equals desulfurizer A pressure, shut MV-1035 (FCV-112 upstream isolation valve).
   h) Close MV 1034 (FCV-112 downstream isolation valve).
   i) Close MV-1030 (desulfurizer B purge valve).
   j) Open MV-1028 (desulfurizer A outlet valve).
   k) Open MV-1036 (desulfurizer B product valve).
   l) Close MV-1033 (desulfurizer A product valve).

Reference



6.15 Purging the Desulfurizer and Preconverter with Nitrogen

Once the desulfurizer and preconverter have had methane flow through them, they must be purged with nitrogen when they are taken out of service. Displacing the methane with nitrogen to below 10% LEL reduces a risk of explosion. If the lines or vessel will be opened the item must be purged with nitrogen to a 5% LEL level. When the purge is about complete, an LEL meter is placed near the vent to measure the level of explosive gas in the discharge. The nitrogen flow rate and total amount of nitrogen used is critical. A flow rate less than 5 scfm may not displace the methane. At least two times the volume of the vessel of nitrogen must be used, if a line or vessel will be opened at least twice that volume is used. Do NOT use a flow rate above 15 scfm, because the equipment could be damage at that high a pressure.

NOTE: The desulfurizer must be isolated before it can be purged, to isolate a desulfurizer see "Running with one desulfurizer online" on page 6-66

This procedure assumes that there is no natural gas flow through the desulfurizer system, either the fuel cell is shut down or the fuel cell is operating but the desulfurizer to be purged is isolated.

WARNING

The nitrogen purge volumes used in this procedure (two volumes) may not enough to make the desulfurizer media completely inert or eliminate the explosive hazards of opening a desulfurizer vessel. Depending on the operating history of the desulfurizer and the maintenance to be performed, higher purge volumes may be necessary. ***In all cases, an LEL detector must be used when opening a desulfurizer vessel, levels must be sustained below 5% LEL before the vessel can be opened.***

Purging desulfurizer A with nitrogen

1. **Connect a nitrogen bottle to MV-1032 (desulfurizer N2 purge valve). Use a pressure regulator and flow meter capable of measuring 5 scfm flow.**
2. **Verify that desulfurizer A is isolated. Close or check that the following are closed:**
   a) MV-1020 (desulfurizer A inlet valve)
   b) MV-1028 (desulfurizer A outlet valve)
   c) MV-1033 (desulfurizer A product valve)
3. **Open MV-1060 (desulfurizer combined vent valve).**
4. **Slowly open MV-1018 (desulfurizer A vent valve) to reduce pressure in the desulfurizer. Wait until venting flow stops before continuing, and check that desulfurizer A pressure (PI-107) is zero.**
5. **Open MV-1029 (desulfurizer A purge valve).**
6. **Open MV-1032 (desulfurizer N2 purge valve) and begin to purge desulfurizer A.**
   Purge with 250 scf of nitrogen total. (Purge with 500 scf of nitrogen if this system will later be opened for maintenance or other reasons.)
7. **Listen for flow noise through the vent to verify flow through the desulfurizer A and check that vessel pressure (PI-107) remains near zero.**

NOTE *If the purge flow meter reads less than 5 scfm at any time during the purge, then increased the total purge time to compensate for the time that the flow was below 5 scfm.*

WARNING

If the desulfurizer vessel is to be opened, sample the gas flow from the desulfurizer vent using a portable LEL detector before stopping the nitrogen purge. The percent LEL should be below 5%. If not, continue with the nitrogen purge until percent LEL is less than 5%.

Nitrogen itself is not dangerous but it will displace the oxygen in a vessel, which can kill someone by asphyxiation. Isolate and remove the nitrogen supply bottle so that nitrogen cannot be accidentally be put in the desulfurizer vessel.

8. **Isolate and remove the nitrogen supply bottle.**
9. **If the carbon bed is to be removed now, leave the desulfurizer vented to atmosphere and continue to the procedure, *Replacing the carbon media in the desulfurizer*. Otherwise, close MV-1018 (desulfurizer A vent valve) and MV-1060 (desulfurizer combined vent valve).**

Purging desulfurizer B with nitrogen

1. **Connect a nitrogen purge supply to MV-1032 (desulfurizer N2 purge) with a pressure regulator and flow meter capable of measuring 5 scfm flow.**
2. **Ensure desulfurizer B is isolated. Close or verify shut:**
   a) MV-1021 (desulfurizer B inlet valve)
   b) MV-1031 (desulfurizer B outlet valve)
   c) MV-1036 (desulfurizer B product valve)
3. **Open MV-1060 (desulfurizer combined vent valve).**
4. **Slowly open MV-1023 (desulfurizer B vent valve) to reduce pressure in the desulfurizer. Wait until venting flow stops before continuing, and check that desulfurizer B pressure (PI-110) is zero.**
5. **Open MV-1030 (desulfurizer B purge valve).**
6. **Open MV-1032 (desulfurizer N2 purge valve) to begin the nitrogen purge on desulfurizer.** Purge using 250 scf of nitrogen (about 50 minutes). (Purge 500 scf (about 100 minutes) of nitrogen if this system will later be opened for maintenance or other reasons.)
7. **Listen for flow noise through the desulfurizer B vent to verify flow and check that vessel pressure (PI-110) remains near zero.**

NOTE *If the purge flow meter reads less than 5 scfm at any time during the purge, then increased the total purge time to compensate for the time that the flow was below 5 scfm.*

WARNING

If the desulfurizer vessel is to be opened, sample the gas flow from the desulfurizer vent using a portable LEL detector before stopping the nitrogen purge. The percent LEL should be below 5%. If not, continue with the nitrogen purge until percent LEL is less than 5%.

Nitrogen itself is not dangerous but it will displace the oxygen in a vessel, which can kill someone by asphyxiation. Isolate and remove the nitrogen supply bottle so that nitrogen cannot be accidentally be put in the desulfurizer vessel.

8. **Isolate and remove the nitrogen supply bottle.**
9. **If the carbon bed is to be replaced now, leave the desulfurizer vented to atmosphere and continue to the procedure, *Replacing the carbon media in* the desulfurizer. Otherwise, shut MV-1023 (desulfurizer B vent valve) and MV-1060 (desulfurizer combined vent valve).**

Purging both desulfurizers with nitrogen

1. **Connect a nitrogen purge supply to MV-1032 (desulfurizer N2 purge valve). Use a pressure regulator capable of maintaining 15 psig of nitrogen pressure during the purge.**
2. **Be sure the desulfurizers are isolated. Verify the following are closed:**

a) MV-1020 (desulfurizer A inlet valve)

b) MV-1033 (desulfurizer A product valve)

c) MV-1021 (desulfurizer B inlet valve)

d) MV-1036 (desulfurizer B product valve)

3. **Open MV-1060 (desulfurizer combined vent valve).**

4. **Slowly open MV-1018 (desulfurizer A vent valve) and MV-1023 (desulfurizer B vent valve) to reduce pressure in the desulfurizers. Wait until venting flow stops before continuing.**

5. **Open MV-1029 (desulfurizer A purge valve) and MV-1030 (desulfurizer B purge valve).**

6. **Open MV-1032 (desulfurizer N2 purge valve) to begin the nitrogen purge on the desulfurizers. Purge for 100 minutes at 5 scfm. (Purge for 200 minutes at 5 scfm if the system will later be opened for maintenance or other reasons.)**

NOTE If the purge flow meter reads less than 5 scfm at any time during the purge, then increased the total purge time to compensate for the time that the flow was below 5 scfm.

WARNING

If the desulfurizer vessel is to be opened, sample the gas flow from the desulfurizer vent using a portable LEL detector before stopping the nitrogen purge. The percent LEL should be below 5%. If not, continue with the nitrogen purge until percent LEL is less than 5%.

Nitrogen itself is not dangerous but it will displace the oxygen in a vessel, which can kill someone by asphyxiation. Isolate and remove the nitrogen supply bottle so that nitrogen cannot be accidentally be put in the desulfurizer vessel.

7. **Close MV-1032 (desulfurizer N2 purge valve), MV-1029 (desulfurizer A purge), and MV-1030 (desulfurizer B purge valve). Remove the nitrogen supply bottle.**

8. **If the carbon beds are to be removed now, leave the desulfurizers vented to atmosphere and continue to the procedure, *Replacing the desulfurizer carbon media*. Otherwise, close MV-1018 (desulfurizer A vent valve), MV-1023 (desulfurizer B vent valve) and MV-1060 (desulfurizer combined vent valve).**

Purging the preconverter with nitrogen

- When purging the preconverter there can be no fuel gas flow through the preconverter.
- The AGO may be running or off and isolated.

WARNING

Nitrogen flow must remain at least 3 scfm from start to finish or the vessel was NOT properly purged.

1. **Connect a nitrogen bottle to MV-1047 (H2 injection low point valve).**

2. **Do not ever allow supply pressure to be above 15 psig, use a regulator if necessary and a flow meter capable of measuring 5 scfm.**

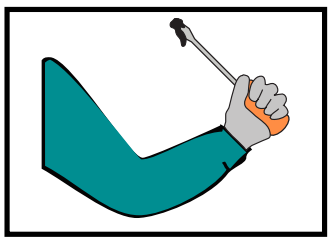
3. **Trace the flow path and verify the valves are open from the nitrogen bottle through the Preconverter, and to atmosphere.**

4. **Open MV-1047 and start the nitrogen purge at no greater than 15 psig. Flow nitrogen for at least 30 minutes at 3 scfm.**

5. **When the purge is complete, stop the nitrogen flow and close MV-1047 (N2 injection low point valve).**

6. **Remove the nitrogen bottle if no longer needed.**

Reference



6.16 Replacing the Filter Media on the Fuel Preparation System

The media in the desulfurizers, the filters in the desulfurizer after-filter, and preconverter after filter must be replaced when sampling indicates that the carbon is spent. The desulfurizer vessels are permit required confined spaces and all King County confined space procedures must be followed. To work with the KOA activated carbon you must use a respirator, gloves, and safety goggles or glasses. Properly characterize, store, transport and dispose of the spent carbon as hazardous material per applicable U.S. EPA, U.S. DOT, and state guidelines.

Replacing the carbon media in the desulfurizer

This procedure requires two people and takes about 18 hours to complete.

This procedure requires working above the desulfurizer enclosure. This requires fall protection safety precautions that are met by using scaffolding with handrails. If handrails are not used, a personnel safety harnesses must be used when working above the desulfurizer enclosure.

WARNING

The desulfurizer vessels are permit required confined spaces. Odorless desulfurized natural gas may be present. During this procedure there is no smoking, no sparks or open flames, or unauthorized people in the area.

Used KOH activated carbon may contain hazardous chemicals or exhibit hazardous properties that may have to be examined to determine appropriate disposal. Wear appropriate personal protective (PPE) equipment when handling this material. You must use a respirator, gloves, and safety goggles or glasses. Properly characterize, store, transport and dispose of the spent carbon as hazardous material per applicable U.S. EPA, U.S. DOT, and state guidelines.

Fresh KOH activated carbon may have a high pH. Wear appropriate PEE when handling this material, Use a respirator, gloves, and safety goggles or glasses.

Use proper fall protection.

Requirements. This task requires the following personnel protective equipment (PPE):

- Disposable one-piece, hooded coveralls with shoe covers
- Respirator with HEPA filter
- Rubber gloves
- Safety goggles

The following items will be need to complete the task, do not start until you have all the proper parts and equipment.

- One 8-150# flexitalic gasket
- One 12 x 16 rubber manway gasket (required only if installed gasket requires replacement)
- 2,050-lbs. bags of activated carbon (FCE p/n 2,699)
- 150 ft^3 of nitrogen
- Five 55-gallon steel drums with covers

You will need the following tools and equipment:

- One 1 1/4-inch combination wrench
- One 11/4-inch socket and ratchet
- Loading hopper
- Barrel type vacuum with HEPA filter
- Ladder (or other means to gain access to the top of Skid 1)
- Scaffolding with side rails
- LEL detector

CAUTION

After replacing the carbon media, the desulfurizer must be purged with nitrogen and vented to atmosphere before being put in service. This allows the normal carbon dust to bevented safely and not contaminate the downstream equipment.

The desulfurizer carbon media is changed when sampling analysis detects sulfur (greater than 1ppm) at the outlet of that desulfurizer.

WARNING

*Verify that the desulfurizer has been purged nitrogen **immediately before** you remove the desulfurizer access flanges and open the vessel. Lockout and tag out the desulfurizer in place, using standard King County lock out procedures.*

1. **If not already done, purge the vessel with nitrogen.**
2. **Vent the desulfurizers.**
   Vent desulfurizer A
   a) Vent desulfurizer A by opening MV-1018 (desulfurizer A vent valve) and slowly opening MV-1060 (combined desulfurizer vent isolation).
   b) Wait until venting flow stops before continuing. Check PI-107 (desulfurizer A pressure gauge) to verify the vessel pressure is zero.

   Vent desulfurizer B
   a) Vent desulfurizer B by opening MV-1023 (desulfurizer B vent valve) and slowly opening MV-1060 (combined desulfurizer vent isolation valve).
   b) Wait until venting flow stops before continuing. Check PI-110 (desulfurizer B pressure gauge) to verify the vessel pressure is zero.
3. **Fill out a confined space work permit**
4. **Before opening the vessel, install an LEL detector with audible alarm and start it sampling near the vessel access location.**
   This detector should stay in place for the duration of the vessel being opened.
5. **Open the upper manway access. Inspect the hatch's rubber gasket, and replace it if necessary.**
6. **Removed the spent KOH-activated carbon into the 55-gallon barrels using a barrel vacuum with HEPA filter.**
7. **Remove the lower hand hole. Remove any remaining media through the lower hand hole using the vacuum.**
8. **Inspect the media support screen and other item inside the vessel for damage or wear.**
9. **Reinstall the lower hand hole using a new flexitalic gasket.**
   Torque the bolts to 200 ft.-lbs using a star pattern in three increments: 75#, 150#, 200#
10. **Put in the new KOH activated carbon through the upper manway.**
11. **Reinstall the upper manway.**
    Install the two nuts on the strongback bolts, tighten as necessary to seal the neoprene gasket and pressure test to prove a seal.
12. **Purge this desulfurizer with nitrogen, *see Purging a desulfurizer with nitrogen*.**
13. **To be sure you have purged the vessel enough, use a portable LEL detector to sample for oxygen at the desulfurizer vent.**
    The oxygen content should be less than 3% before the nitrogen purge is finished.
14. **Put the desulfurizer in the guard position.**
    Put desulfurizer A/B in the guard position, see "Putting a desulfurizer back in service" on page 6-68.

Replacing the filter on the desulfurizer afterfilter (100-fl-102)

WARNING

Used KOH activated carbon may contain hazardous chemicals or exhibit hazardous properties that may have to be examined to determine appropriate disposal. Wear appropriate personal protective (PPE) equipment when handling this material. You must use a respirator, gloves, and safety goggles or glasses. Properly characterize, store, transport and dispose of the spent carbon as hazardous material per applicable U.S. EPA, U.S. DOT, and state guidelines.

CAUTION

A new afterfilter vessel head gasket should be installed every time the head is re-installed. Failure to do this could result in leaks during fuel cell operation.

The desulfurizer afterfilter elements should be replaced when afterfilter differential pressure reaches 2 psi (56 WC).

1. **Remove the afterfilter vessel head.**
2. **Remove the endcap and replace the filter element.**
   Be sure the filter element is properly seated on the seating ring before re-installing the endcap.
3. **Install the vessel head with a new gasket.**
   Torque the head to 200 ft.-lbs in two increments (100, 200 ft.-lbs) using a star sequence.

Replacing the filter on the preconverter afterfilter (100-FL-102)

NOTE: This filter has been removed, only the housing remains.

Sulfur analysis sampling

To analyze the sulfur content of the methane samples are sent to the FCE lab Connecticut.

Shipping requirements. The following procedure for shipping dangerous goods is specifically for the air shipment of natural gas samples. These shipping instructions conform to the 2004 Dangerous Goods Regulations 45th Edition of the International Air Transport Association (ATA).

NOTE: Prior arrangements with the laboratory are typically required to assure rapid sample analysis turnaround. FCE gas sampling protocol calls for overnight shipping of gas samples, on the day they are taken, and same day analysis in the laboratory.

Sample container requirements. DOT-3E 1800 gas cylinders (DOT approved type 3E cylinders pressure rated for 1800 psi (or higher) are acceptable for samples of natural gas. These markings will be stamped into the sidewall of the cylinder along with the cylinder's date of manufacture (or retesting). 3E cylinders must be re-inspected within 10 years of manufacture ((It is illegal to fill a DOT specification cylinder after its due date for re-inspection if it has not been re-inspected.) Sample cylinders are typically obtained from the analytical laboratory in a condition ready for sampling.

Taking samples

Please read the shipping requirements above to verify the cylinder you use is legal and safe.

1. **Contact the laboratory and let them know you will be shipping a sample.**
2. **Purge the cylinder.**
   To get a clean sample the cylinder is thoroughly purged with the sample natural gas, by filling the cylinder with sample gas and emptying it at least 10 times.
   a) Purge the line once. Connect the sample line to the natural gas sample source and purge the line to a safe location for a minimum of 60 seconds
   b) Purge the cylinder 10 times.
      1) Connect the sample cylinder to the sample line. Fully open the cylinder inlet and outlet valves and purge the cylinder with natural gas to a safe

location for a minimum of two minutes.

2) Fill the cylinder. Fully close the cylinder outlet valve and allow the cylinder to pressurize with natural gas.
3) Fully close the cylinder inlet valve.
4) Empty the cylinder. Fully open the cylinder outlet valve to allow the cylinder to depressurize.

c) Fully close the cylinder outlet valve and again open the cylinder inlet valve and repeat the above filling and venting process a minimum of 10 times.

3. Take the sample.

a) Again open the cylinder inlet valve and partially open the cylinder outlet valve to further purge and condition the sample cylinder with the natural gas source. Purge to a safe location for a minimum of two minutes.

b) Close the cylinder outlet valve and allow the sample cylinder to completely pressurize a minimum of 60 seconds.

c) Close the cylinder inlet valve and then the gas source valve. Disconnect the cylinder and sample hose and cap all connections (required).

d) Check all valves and end caps for tightness.

4. Identify the sample.

After sampling, record sample ID information on the cylinder tag (include the unit #, sample date and time) and secure (tape) the cylinder knobs to prevent loosening during shipment (required).

5. Package the sample for shipment.

The cylinder must be shipped in a strong outer package. Outer package must be of sufficient size to prevent contact of cylinder with the package and to affix the required labels and markings. All inapplicable labels and markings should be obliterated, or preferably removed Package must be a strong fiberboard box with an inner liner or a Pelican-type foam-sculpted plastic shipping case is recommended. Note: Pre-printed Fed-Ex packaging is NOT allowed.

NOTE: Box must be of adequate size to accommodate the labels and markings.

a) Pack the cylinder with adequate cushioning (bubble wrap. Styrofoam peanuts, or foam sculpting) to prevent the cylinders) from shifting inside the box. Tape box or closures shut.

6. Label the package.

Attach the following labels (stickers) on the (same) side of the package being shipped.

- Label for flammable gas, a red label with a white (or black) flame displaying the number 2 in the bottom corner.
- DANGER — DO NOT LOAD IN PASSENGER AIRCRAFT

Provide the following markings on the same side of the package as the labels.

- Full name and address of shipper and consignee (the destination).
- METHANE COMPRESSED UN1971
- AIR ELIGIBLE with an airplane symbol alongside the methane compressed label.

7. Fill out the FedEx on-line shipping document.

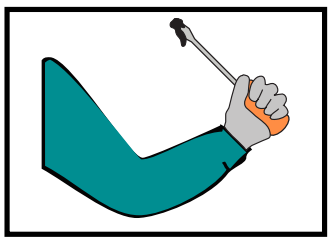
You will need a FedEx account, logon and password. For more information on filling out the shipping documents see the FedEx web site on USA airbill or the back of this manual.

8. Be sure the HAZARDOUS MATERIAL is selected when doing any on-line shipment

9. Fill out the shipper's declaration for DANGEROUS GOODS.

See the FedEx web site on dangerous goods or the back of this manual.

Reference



6.17 Operating the Nitrogen System

The nitrogen systems are critical to the fuel cell operation, because they purge the methane from the system on shut down the fuel cell system cannot be started unless the system is operating. The supply bottles must be nearly full (more than 1000 psi for the slow purge system, and 1700 psi for the rapid purge system) and the instrument air system must be active to support the air actuated valves. If the instrument air system fails the air stored in the IA receiver will actuate the valves. The bottles are filled with compressed nitrogen and the nitrogen must be regulated for the system to 35-45 psi to prevent damage to the lines and instruments. The six-packs are in wheeled carts, and should not be removed from the cart.

Before starting the nitrogen the systems

Verify following conditions:

- Instrument and control circuits are energized.
- Instrument air is available to verify rapid purge and slow purge valves XV-191, XV-280, XV-282, and XV-284, and the valves are closed.
- All maintenance on system has been completed and tested or the nitrogen system is being started up to perform testing.
- A nitrogen 6-pack is connected to MV-1052 for rapid purge, and to MV-1053 for slow purge. If the 6-packs not installed, install using the 6-pack change out procedure.
- Complete the valve lineup, if required.

Starting the slow purge system

1. **Slowly open all bottle isolations and then slowly open the combined isolation valve on the 6-pack.**
2. **Slowly open the nitrogen header isolation valve MV-1053.**
3. **Monitor pressure on gauge PI-176 to ensure bleed header pressure is not over 45 psig.**
   If the pressure is over 45 psig the reducer PCV-175 may need to be adjusted, the header pressure should be 35 to 45 psig.
4. **Verify header supply pressure is greater than 1000 psig on PI-162 (Located on the DCS screen).**
   If the pressure is less than 1000 psig change out 6-pack using the *Changing the slow purge 6-pack* procedure.
5. **Verify that alarms for PSHL-190 (PAL-190 and PAH-190) and PI-162 (PAL-162 and PALL-162) are clear.**

NOTE *If the low low pressure alarm (PALL-162) is active (PI-162 less than 800 psig) the fuel cell system cannot be started, if the low low alarm activates during startup the fuel cell plant will go to hold.*

Starting the rapid purge system

1. **Slowly open all bottle isolations and then slowly open the combined isolation valve on the 6-pack.**
2. **Slowly open the nitrogen header isolation valve MV-1052.**
3. **Monitor pressure on gauge PI-173 to be sure the rapid purge header pressure is not over 45 psig.**
   If the pressure is over 45 psig the reducer PCV-172 may need to be adjusted, the header pressure should be 35 to 45 psig.
4. **Verify header supply pressure is greater than 1700 psig on PI-186 (Located on the DCS screen).**
   If the pressure is less than 1700 psig change out the 6-pack using the *Changing the rapid purge 6-pack* procedure.
5. **Verify that alarms for PSHL-189 (PAL-189 and PAH-189) and PI-186 (PAL-186 and PALL-186) are clear.**

NOTE *If low low pressure alarm PALL-186 is active (PI-186 less than 1500 psig) the fuel cell cannot be started. If the alarm activates during startup the fuel cell plant will go to hold.*

Changing the rapid purge six-pack

NOTE The rapid purge six-pack is in front of the slow purge six-pack. If you need to change the rapid purge six-pack, check the slow purge system and see if it is due for a change.

1. **Close all bottle isolations and then close the combined isolation valve on the rapid purge six-pack.**
2. **Open valve MV-1054 to bleed residual pressure on the high-pressure supply line. Verify that pressure is zero on gauge PI-187.**
3. **Close valve MV-1052 and MV-1054.**
4. **Disconnect the hose from six-pack and remove six-pack from enclosure using an approved method to transport the six-pack.**
5. **(If required change out the slow purge nitrogen six-pack at this time.)**
6. **Install a new six-pack and connect it to the flex hose at MV-1052.**
7. **Place rapid purge six-pack back in service using the *Starting the rapid purge system* procedure.**
8. **Check the six-pack connections for leaks.**

Changing the slow purge six-pack

1. **Remove the rapid purge six-pack**
2. **See *Changing the rapid purge six-pack* above.**
3. **Close all bottle isolations and then close the combined isolation valve on the slow purge six pack.**
4. **Open MV-1055 to bleed residual pressure on the high-pressure supply line. Verify that pressure is zero on gauge PI-163.**
5. **Close valves MV-1053 and MV-1055.**
6. **Disconnect the hose from the six-pack and remove the six-pack from enclosure.**
   Use an approved method to9 transport the six-pack.
7. **Install a new six-pack and connect it to the flex hose at MV-1053.**
8. **Place slow purge six-pack back in service using the *Starting the slow purge system* procedure.**
9. **Check the six-pack connections for leaks.**
10. **Re-install the rapid purge six-pack.**
11. **Disconnecting the nitrogen systems**

Disconnecting the rapid purge six-pack

1. **Close all the bottle isolations and then close the combined isolation valve on the rapid purge six-pack.**
2. **Open MV-1054 to bleed residual pressure on the high-pressure supply line. Verify that pressure is zero on gage PI-187.**
3. **Close valves MV-1052 and MV-1054.**
4. **Disconnect the hose from the six-pack and remove the six-pack from the enclosure.**
   Use an approved method of transportation.

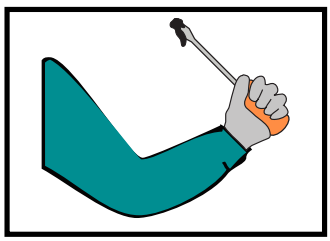
Disconnecting the slow purge six-pack

1. **Close all the bottle isolations and then close the combined isolation valve on the slow purge six pack.**
2. **Open valve MV-1055 to bleed residual pressure on the high-pressure supply line. Verify that pressure is zero on gage PI-163.**
3. **Close valves MV-1053 and MV-1055.**
4. **Disconnect the hose from the six-pack and remove the six-pack from the enclosure.**
   Use an approved method of transportation.

KCPP DFC1500-1 Nitrogen system pre-startup valve lineup

Valve	Description	Position	Notes
Proprietary information— Not Available for Publication.			

Reference



6.18 Operating the AGO System

The anode gas oxidizer (AGO) system has a blower, a anode gas oxidizer (the portion of the burner that uses a catalyst to remove excess hydrogen or methane in the anode exhaust), and the heat recovery unit which process the heated exhaust gas. Once the blower is started the air is used to purge the burner to remove any lingering methane in the chamber before lightup. Once the burner is purged, the pilot is purge with instrument air and lit, then the main burner is lit, and the system at zero output moves to automatic control by the DCS to be used to control the temperature of the fuel cell stack module. (Air flow is also used to control the temperature of the stack.)

After the burner is shutdown, the blower can be used to purge the burner for process reasons, but nitrogen must be used to purge the burner if it requires any maintenance. The AGO burner skid falls under hot work requirements.

Before starting the system

Before starting the anode gas oxidizer (AGO system) the following conditions must be met:

AGO blower. For the AGO or combustion air blower to run the following interlocks must be satisfied:

- No field E-STOP buttons have been pushed. Check that all the hand switches (HS-111A–G) on the Emergency Shutdowns, Fire, and Gas Alarms screen are green. Select the RESET button to reset.
- The burner management system (BMS) E-STOP button (HS-231B) has not been pushed. Push ESD Reset (PB-62B) on the control panel and then reset the AGO at the DCS on the AGO screen (HS-231A).
- Valve XV-241 (automatic air blower discharge valve) is open
- There is no high vibration alarm (VAH-224)

Burner management system. For the anode gas oxidizer burner to be ready, the following conditions must be met:

  - Purge must be completed
  - Panel power must be on
  - Fuel gas pressure cannot be high or low. (PSL-210, PSH-215)
  - No emergency shutdown (ESD) have been initiated (locally at PB-62A or remotely at HS-231A)
  - Combustion air pressure is not low. (DPSL-233)
  - Instrument air pressure is not low. (PSL-261)
  - Combustor temperature not high. (TSHH-246)
  - A flame is detected in 1 of 2 detectors (bypassed for start up).
  - Pilot air pressure not low. (PSL-226)
  - Combustion air blower is running (XL-224)
  - Plant is not in an emergency shutdown
- Before the burner system can be purged for startup these conditions must be met:
  - Fuel gas control valve closed. (FV-208A)
  - Pilot gas block valve #1 closed. (XV-203)
  - Pilot gas block valve #2 closed. (XV-205)
  - Main gas block valve #1 closed. (XV-212)
  - Main gas block valve #2 closed. (XV-214)
  - Combustion airflow greater than purge airflow, a minimum of 880 scfm.
  - Fuel gas control at minimum fire position. (FV-208B)
  - No flame (BSL-233, BSL-234)

Starting the AGO system

1. **Verify valve line up is correct for the instrument air and fuel gas valves to the AGO.**
   See _____, and "KCPP DFC1500-1 Instrument air system pre-startup valve lineup" on page 6-96.
2. **Turn the power to BMS control panel to POWER ON.**

3. **Press the ACKNOWLEDGE button.**
4. **Press the RESET button.**
5. **Press the SYSTEM STOP/RESET button.**
6. **Verify the LIMITS SATISFIED light is lit.**
7. **Press the SYSTEM LOCAL START button.**
8. **Check that the purge and lighting cycle is completed as follows (both locally and on the DCS):**
   a) PURGING light comes on.
   b) Purge occurs for 2 minutes. (Primary airflow should be greater than 880 SCFM to provide a minimum of four changes of air).
   c) After 2 minutes, the pilot gas valves XV-203 and XV-205 open; and pilot air valve XV-260 opens.
   d) After about 10 seconds the pilot should light, and then main gas block valves XV 212 and XV 214 should open and the main burner should light and the pilot gas should shutoff and the flame extinguish, the BAL-233 SCANNER 1 FLAME ON or BAL-243 SCANNER 2 FLAME ON light should come on.

NOTE: If the flame scanners do not indicate a flame, restart the purge and lighting cycle.

9. **Once the main burner has lit, the AGO burner should now operate automatically from the DCS.**

NOTE: If the main flame fails to start and the pilot goes out, then the AGO must be restarted using "Starting the AGO system".

CAUTION

To minimize the potential of thermal shock and or cycle damage to the catalyst, when heating or cooling the system, the temperature change should be no more than 300°F per hour. This would be a ramp up using a set point of 5°F per minute.

Shutting down rapidly (an emergency)

1. **Press EMERGENCY STOP button on the BMS control panel, or the REMOTE EMERGENCY SHUTDOWN in the control room.**

Locking out and purging the natural gas desulfurized (NGD) to the AGO skid

If the AGO system requires maintenance the natural gas supply to the skid must be locked out and the lines purged with nitrogen to limit the possibility of an explosion.

1. **Shut MV-2010 (natural gas desulfurized (NGD) to anode gas oxidizer isolation).**
   Attach a lockout and tag to the valve.

NOTE: This is a only process lockout of the methane supply, to lockout the system the electrical lockout must also be completed.

2. **Attach a nitrogen bottle to the manual drain valve immediately downstream of FV 208A.**
3. **Use the DCS or manually test that all NGD supply valves are open so that all NGD lines vent into the AGO.**
4. **Attach an LEL detector to PI 216 on the sensing line.**

WARNING:

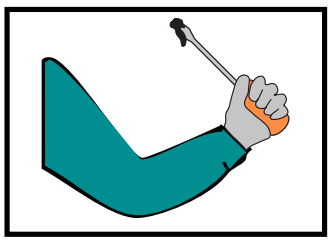
Be sure that no one is inside the anode gas oxidizer before starting and during the nitrogen purge.

5. **Purge the lines with nitrogen at 5 scfm for 10 minutes.**
   To correctly purge the piping, 5 scfm must be maintained for the entire 10-minute purge. If the flow drops below 5 scfm anytime during the purge then do not count that time and increase the purge so that there is a full 10 minutes at 5 scfm.

WARNING

If any pipe is to be opened, sample the flow of gases venting from the piping using a portable LEL detector IF the percent of LEL is not below 5%, continue the nitrogen purge until percent LEL is less than 5%.

6. **When the purge is complete, close the supply valve and remove nitrogen bottle from the manual drain valve immediately downstream of FV-208A.**



6.19 Operating the Water Treatment System

The water treatment system supplies the purified water for the steam in the anode fuel gas. The system is complex, but largely runs without operator intervention to maintain a 12-hour supply of water for the system, and recycles water to keep the system active while the fuel cell is in service.

Before starting the water treatment system

1. **Check there is power to the water treatment system.**
   If necessary close the circuit breakers 166F on panel 600-LP-B and 156B on the 480VAC panel.
2. **Verify the instrument and control circuits are energized.**
3. **Check that the 480V auxiliary power bus is energized.**
4. **Check that the sanitary sewer drains are working.**
5. **Check the local pump hand switches are in OFF.**
6. **Check the three system pumps have been properly lubricated.**
7. **Check that all on-line conductivity meters have been calibrated.**
8. **Check that all equipment has been fully assembled, and that all electrical and control systems are restored from prior maintenance. Verify that all administrative procedures connected with the maintenance activity have been completed.**
9. **Verify the water treatment skid controller local timer settings:**
   - The media filter and carbon filter back-wash every 7 days. They backwash for 24 minutes, rinse for 6-minutes, and settle for 6 minutes.
   - The softeners regenerate for 82 minutes (total cycle).
10. **Check that the brine tank, 400-WT-101-TK-1, contains the proper level of brine mixed according to vendor's instructions.**
11. **Check the antiscalant tank, 400-WT-101-TK-2, contains the proper level of antiscalant solution.**
    (Currently there is 5 gallons of Hyperspesre MS 1310 in tank).
12. **Verify or valve in the initial valve lineup.**
    See "KCPP DFC1500-1 Water treatment system pre-startup valve lineup" on page 6-86.
13. **Check that city water is available at block valve MV-4001.**
14. **Check that the control valve FV-131 is in MANUAL at the DCS, and is closed.**
15. **Verify that all instrument isolation valves are open.**

Starting the water treatment system

1. **At the US Filter control panel, turn the RO Mode Select, RO Flush Mode Select and RO Pump Mode Select switches to AUTO.**
2. **Verify reverse osmosis (RO) flow in the 60-second pre-service flush by watching that the RO reject flow on FIT-401A is normal (~2.5 gpm).**
3. **Verify that after 60 seconds the RO unit is in normal service by watching the RO Product flow on FIT-401B is normal (~3.5 gpm)**
4. **At the US Filter control panel, turn the Product Pump Mode Selector switch for PU-3 and 4 to AUTO. Turn the Pump Duty Selector Switch to either PU-3 or 4 to energize the pump.**
5. **Verify the recirculation and product flow on FIT-405A and B is normal (A ~ 1.0 gpm, B ~ 2.0 gpm).**
6. **Verify that flow (make-up rate) through the continuous deionization unit (CDI) on**

FIT-403A is higher than product flow to FV-131.
If FIT-403A < FIT-405B, adjust the recirculating flow diaphragm valve closed until CDI flow is greater than product flow.

Shutting down the water treatment and distribution system

Shutting down following a power loss. If power to the US Filter equipment is lost, all valves (except normally-open valves) at the equipment will close and all pumps will stop.

1. **Place all the selector switches at the US Filter control panel to the OFF position.**
2. **Try to determine what the operating status of the equipment was when the power was lost.**
   This information will be helpful when the system is restarted.

WARNING

This equipment has both electical and pnuematic (IA) power sources. If any equipment needs to be worked on, it must be locked out and tagged out according to King County lockout procedures. This means isolating and disconnecting both the power and air supplies.

NOTE: If it is necessary to continue to operate the US Filter equipment during a total power loss, portable generators can be used to keep the equipment in service.

Restarting after a power loss

When electrical power is restored to the system, do the following:

1. **Check the main control panel for indications of normal panel operations.**
   If there is no activity at the panel controls and instruments, the controller backup battery maybe dead. If this happens, the entire controller program may have to be reloaded before the system can be operated again.
2. **Check, note, troubleshoot, clear and acknowledge any alarm conditions at the main control panel.**
3. **Return all selector switches at the US Filter panel to their normal positions**
4. **Restart the individual trains in the US Filter system as required.**
5. **Verify everything is operating normally.**
   See *Checking the water treatment system below*.

Checking the water treatment system (normal operation)

These are not daily checks, but these items should be checked after restarting the system.

1. **Check the fuel cell city water use at the water meter (located ___)**
2. **Check the DI water flow rate at FIT-405B.**
3. **Check the RO reject flow rate at FIT-401A and the recycle flow on local rotameter FI-426.**
4. **Check the CDI unit reject flow at FIT-403B.**
5. **Check intermediate pressure throughout the system on local gauges.**
   Check the differential pressure (DP) across the water softener and each filter against the normal setting found in the pretest book. A change in flow or pressure can indicate partial plugging or a leakage in the equipment
6. **Check the salt level in the softener brine tank.**
   Add salt as required.
7. **Monitor the DI water conductivity at DCS CI-403A/B and CI-402B, using trend plot.**
   A sudden change may indicate serious problems.
8. **Check treated water temperature and quality by water analysis.**
   The analysis conductivity should be close to conductivity readings at DCS. A lab analysis is only way to detect hydrocarbons in the water.
9. **Check the DI water transfer pumps (PU-3/4).**
   a) Check the lube oil level.
   b) Note any leaks, unusual noise or vibration.
   c) Check that local PLC has not started the spare DI water transfer pump. Only one pump should run at a time.

10. **Look at the micro filter on the storage tank; be sure it is not plugged.**
    Check that the filter element is not covered with dirt.

11. **Monitor the DI water flow rate to the humidifier, at DCS FC-131, using a trend plot.**

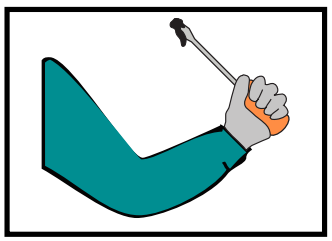
NOTE: Flushes and regens of the water softener and carbon filters are done automatically by the PLC and require no operator action.

KCPP DFC1500-1 Water treatment system pre-startup valve lineup

Valve	Description	Position	Notes
LT-402 Root	WTS Storage Tank Level Detector Isolation	OPEN	
PI-401-Root	Activated Carbon Filter Inlet Pressure Gage (PI-401) Isolation	OPEN	
PI-431 Root	RO Outlet Pressure Gage Isolation	OPEN	
MV-4001	City Water Supply to WTS	OPEN	
MV-4015	Jelcleer Filter Outlet Isolation	OPEN	
MV-4012	Carbon Filter Outlet Isolation	OPEN	
MV-4017	Jelcleer Filter Bypass	SHUT	
MV-4016	Jelcleer Filter Outlet Sample Valve	SHUT	
MV-4018	Water Softener Inlet Isolation	OPEN	
PI-405-Root	Jelcleer Filter Outlet Pressure Gage (PI-405) Isolation	OPEN	
MV-4019	Water Softener Outlet Isolation	OPEN	
MV-4014	Jelcleer Filter Inlet Isolation	OPEN	
MV-4011	Carbon Filter Inlet Isolation	OPEN	
MV-4013	Carbon Filter Outlet Sample Valve	SHUT	
PI-403-Root	Activate Carbon Filter Outlet Pressure Gage (PI-403) Isolation	OPEN	
MV-4010	City Water Supply Sample Valve	SHUT	
PI-401 Root	SDI Recirc Pressure Gage Isolation	OPEN	
MV-4020	Antiscalant Pump Valve	OPEN	
MV-MB1	CDI Outlet Isolation/Mixed Bed DI Inlet Isolation	OPEN	
MV-LX1	Inlet CDI	OPEN	
MV-LX2	Inlet CDI Reject Stream	OPEN	
FCV-435	CDI Reject Stream Flow Control Valve	OPEN	
XV-443	Storage Tank Inlet Control Valve	AUTO	
PI-447-Root	PU-3 Discharge Pressure Gage (PI-447) Isolation	OPEN	
MV-4038	PU-3 Water Transfer Pump Discharge Valve	OPEN	
MV-4039	PU-4 Water Transfer Pump Discharge Valve	OPEN	
MV-4040	Transfer Pump Header Sample Valve	SHUT	
PI-448-Root	PU-4 Discharge Pressure Gage (PI-448) Isolation	OPEN	
PI-450 Root	DI Water to HRU Pressure Gage (PI-450) Isolation	OPEN	
MV-4041	Transfer Pump Recirc Flow Control Valve	THROTTLE D OPEN	

KCPP DFC1500-1 Water treatment system pre-startup valve lineup

Valve	Description	Position	Notes
MV-4042	Transfer Flow Control Valve	SHUT	
MV-4037	Water Transfer Pump PU-4 Inlet	OPEN	
MV-4036	Water Transfer Pump PU-3 Inlet	OPEN	
MV-4035	DI Water Storage Tank Vent/Overflow	SHUT	
MV-MB3	Filter Housing Outlet Isolation	OPEN	
MV-MB2	Mixed Bed DI Outlet Isolation	OPEN	
SP-LX2	CDI Outlet Sample Line	SHUT	
SP-LX3	CDI Reject Stream Outlet Sample Line	SHUT	
SP-LX4	CDI Reject Stream Inlet Sample Line	SHUT	
SP-LX1	CDI Inlet Sample Line	SHUT	
MV-MB1A	Mixed Bed DI Inlet Isolation	OPEN	
PI-409-Root	RO Prefilter Inlet Pressure Gage (PI-409) Isolation	OPEN	
MV-4021	Water Softener Outlet Sample Valve	SHUT	
MV-4026	FL-3 Inlet	OPEN	
XV-442	Storage Tank Return To RO Booster Pump	AUTO	
MV-4024	FL-4 Inlet	OPEN	
MV-4022	FL-5 Inlet	OPEN	
MV-4028	RO Prefilter Inlet Pressure Transmitter (PT-410) Isolation	OPEN	
MV-4033	Drain at RO Discharge	SHUT	
MV-4029	RO Prefilter Outlet Pressure Transmitter (PT-411) Isolation	OPEN	
MV-4027	FL-3 Outlet	OPEN	
MV-4025	FL-4 Outlet	OPEN	
MV-4023	FL-5 Outlet	OPEN	
PI-414-Root	RO Prefilter Outlet Pressure Gage (PI-414) Isolation	OPEN	
MV-4030	RO Pre-Filter Outlet Sample	SHUT	
MV-4031	RO Booster Pump Outlet Isolation	OPEN	
PT-419-Root	RO Membrane Outlet Pressure Transmitter Gage (PT-419) Isolation	OPEN	
MV-4032	RO Unit Outlet Sample Valve	SHUT	
PIT-417-Root	RO Membrane Inlet Pressure Transmitter (PIT-417) Isolation	OPEN	
MV-4034	DI Water Storage Tank Drain	SHUT	
RO Booster pump Inlet Sample	RO Booster Pump Inlet Sample	SHUT	
XV-415	Water Control Valve To RO Booster Pump	AUTO	
PT-418-Root	RO Recirc Pressure Transmitter (PT-418) Isolation	OPEN	
MV-4002	Treated Water Supply to HRU	OPEN	
MV-4003	Treated Water Low Point Drain	SHUT	



6.20 Operating the EBOP

The electrical balance of plant (EBOP) enclosure contains most of the electrical equipment for the fuel cell plant. In a utility power failure the fuel cell system will need to be isolated to protect the fuel cell from damage when utility power is restored. The fuel cell will shut down automatically using power from the UPS and the IA receiver tanks.

To startup the electrical system of the fuel cell plant requires and orderly closing of the various circuit breakers that supply power to the skids and components that comprise the fuel cell system. There is also a power conditioning system. There is an incoming interface with South Plant power that supplies utility power to the fuel cell system, and there is also a outgoing interface that supplies power from the fuel cell to the power grid.

Because the fuel cell system is complex and requires an orderly startup, when it is shutdown it is also be isolated from electrical power to protect the equipment and processes from an accident startup. This shutdown and isolation is called securing the fuel cell. You must secure the system in one of two ways, one if fuel gas has been flowing to the fuel cell stack module and another if the fuel has not started to flow.

The EBOP also house the UPS, this critical system maintains enough battery power to shutdown the fuel cell system in an orderly manner using the air from the IA receivers to actuate the various isolation valves and valve used to purge the fuel gas from the system.

Shutdown due to a general power failure (fuel cell NOT on line)

If there is a general power failure at South Plant, isolate the fuel cell to prevent damage. Do the following:

1. **In the substation, verify Puget Sound Energy (PSE) input breaker is open and breaker indicator is flagged green, open if necessary.**
   This breaker should have been opened by the F-60 relay. If not, open it manually.
2. **Verify KCPP ABB EBOP input breaker is open and breaker indicator is flagged green, open if necessary.**
   This breaker should have been tripped by the F-60 relay. If not, open manually.
3. **Open breaker CB-151B to the 480V auxiliary power.**
4. **Verify UPS battery output breaker QF-1 is open, open if necessary.**
5. **Open breaker CB-161B (for the Skid 1 Fire Protection Panel).**
   The breaker is inside 600-LP-A panel. Disconnect fire protection panel batteries. Remove the BMS alarm relay inside the BMS control panel.

Before starting the electrical system

Verify that the following initial conditions are met:

- 480V customer interconnection are de-energized, CB-152A, CB-151A, CB-151B open
- UPS (600-U-101) offline, and batteries charged
- UPS manual bypass switch set to NORMAL.
- All 480V and 120V feeder breakers are open
- All 120V branch breakers in 600-LP-A and 600-LP-B are open

Starting the electrical system

1. **Follow the procedure to start the UPS (600-U-101).**
   See “Starting the UPS” on page 6-92.
2. **Close breaker CB-165A, the 50A main disconnect for 600-LP-B.**
3. **In panel 600-LP-B, close breakers CB-165B, 165C, 165D, 165E, and 165H. Then close breakers CB-165F, 165G, 165J and 165K.**
   These circuits will energize the EBOP control systems and critical loads

4. **Have a King County electrician or PSE electrician energize the 480V customer interconnection line in accordance with the King County procedures.**
5. **Verify that voltage and frequency on the line are within tolerance by checking the metered values on the F60 relay.**
6. **Close breaker CB-152A by pressing the CLOSE switch on the breaker.**
7. **Close breaker CB-151B to energize the 480V auxiliary power bus.**
8. **Close breaker CB-156D, then CB-156E to provide bypass power to the UPS.**
9. **Close breaker CB-155C, then CB-160A, to energize the normal-power panel board 600-LP-A.**
10. **In panel 600-LP-A, close breakers CB-160B, 160C, 160D, 160E, 160F, 161A and 161J to energize the various EBOP systems and air conditioner.**
11. **Close breakers CB-158A to energize the EBOP heating resistors.**
12. **Energize the DCS by closing the circuit breakers mounted in the bottom left corner of the DCS I/O panel.**
13. **Energize the fuel cell plant 120V UPS loads one at a time by closing the corresponding branch breakers in 600-LP-B.**
    Refer to the panel schedules on drawing number 437000-67K-20
14. **Energize the fuel cell plant 208/120V normal power loads one at a time by closing the corresponding branch breakers in 600-LP-A.**
    Refer to the panel schedules on drawing number 437000-67K-20.
15. **Energize the fuel cell plant 480V loads one at a time by closing the corresponding breakers (CB-155A, 155B, 155D, 155E, 156A, 156B, 157B, 157C and 157D).**
    Refer to the one-line diagram 437000-67E-13.
16. **If the customer's critical loads are connected, verify that these are prepared to be energized, and then close breaker CB-151A.**

Securing the electrical balance of plant (EBOP)

Securing the plant shuts off the electrical energy to the fuel cell system. The word secure is used because this is a process lockout only. Each system and piece of equipment must be locked out in accordance with standard King County lockout and tag out procedures before any work can be done on it. The main electrical equipment is in the EBOP, however the various sub-systems throughout the fuel cell plant also have disconnects. These disconnects are usually on the equipment VFD or on the system control panel.

Shutting down the electrical system (if the fuel cell has not been producing power). This procedure is used once the EBOP is energized, but before the fuel cell system is started.

1. **Check that the following conditions are met:**
   - The 480V South Plant utility power interconnection is energized.
   - Breakers CB-152A, CB-151A, CB-151B are closed, as necessary.
   - The UPS (600-U-101) is online, and load protected by well-charged batteries.
   - UPS manual bypass switch is in NORMAL
   - All the 480V and 120V feeder breakers are closed, as necessary
   - All the 120V branch breakers in lighting panels 600-LP-A and 600-LP-B are closed, as necessary.
   - Individual systems are energized, as necessary (there are several local disconnects for the various sub-systems of the fuel cell system.
2. **Secure individual sub systems that were operating by opening the breakers once the equipment has been shutdown.**
   Follow the sub-system shutdown procedures.
3. **If any South Plant critical loads are connected, verify that these are prepared to be de-energized, and then open breaker CB-151A.**
4. **De-energize the fuel cell plant 208/120V normal power loads one at a time by**

opening the corresponding branch breakers in lighting panels 600-LP-A.
Refer to the panel schedules on drawing number 437000-67K-20

5. **De-energize the fuel cell plant 480V loads one at a time by opening the corresponding breakers (CB-155A, 155B, 155D, 155E, 156A, 156B, 157B, 157C and 157D).**
Refer to the one-line diagram 437000-67E-13.

6. **De-energize the fuel cell 120V UPS loads one at a time by opening the corresponding branch breakers in lighting panel 600-LP-B.**
Refer to the panel schedules on drawing number 437000-67K-20

7. **De-energize the DCS by opening the circuit breakers mounted in the bottom left corner of the DCS I/O panel.**

8. **De-energize the EBOP heating resistors, by opening breaker CB-158A.**

9. **De-energize the various EBOP systems and the air conditioner, by opening breakers CB-160B, 160C, 160D, 160E, 160F, 161A and 161J in lighting panel 600-LP-A.**

10. **De-energize the normal-power panel board 600-LP-A, by opening breaker CB-160A, then CB-155C.**

11. **Provide bypass power to the UPS, by opening breaker CB-156E, and then open CB-156D.**

12. **De-energize the 480V auxiliary power bus, by opening breaker CB-151B.**

13. **Open breaker CB-152A by pressing the OPEN switch on the breaker.**

14. **De-energize the 480V South Plant interconnection line in accordance with the King County procedures.**

15. **In panel 600-LP-B, open breakers CB-165B, 165C, 165D, 165E, and 165H.**

16. **De-energize the EBOP control systems and critical loads, by opening breakers CB-165F, 165G, 165J and 165K.**

17. **Open the 50A main disconnect for 600-LP-B, breaker CB-165A,**

5. **Disable the DC contactors on the EBOP**

18. **Turn off the UPS (600-U-101).**
Follow the vender O&M or the UPS securing procedure.

Securing the fuel cell electrical system (once the EBOP has been energized and the fuel cell has been producing power)

1. **Once the EBOP is energized, and the fuel cell has started to produce power, check that the following conditions are met:**
   - The fuel cell is connected to the grid.
   - The AC 600 Multi-Drives Inverters are operating.
   - Disconnect breakers A110A, A120A, A130A, A140A are closed.
   - CB-111A, CB-121A, CB-131A, CB-141A are close.
   - 480V South Plant interconnection breaker is closed (the grid is connected).
   - Close as necessary, CB-152A, CB-151A, CB-151B.
   - The UPS (600-U-101) is online, and load protected by batteries.
   - The UPS manual bypass switch in NORMAL.
   - All 480V and 120V feeder breakers are closed, as necessary
   - All 120V branch breakers in 600-LP-A and 600-LP-B are closed, as necessary.
   - The individual sub-systems are operating as necessary.

2. **If critical South Plant loads are connected, verify that these loads are ready to be de-energized, and then open breaker CB-151A.**

Note: If plant is in Island mode, the 480V South Plant interconnection breaker must be closed to provide power to the EBOP before placing plant in hot standby.

3. **Place the fuel cell in Hot Standby.**

4. **Verify AC 600 Multi-Drives Inverters are stopped and the AC output breakers: CB-111A, CB-121A, CB-131A, and CB-141A are open.**

screen (HS 301).

6. **Open the DC input disconnect breakers: A110A, A120A, A130A, and A140A.**
7. **Cool down and secure the fuel cell stack module.**
8. **Secure individual sub systems that were operating by opening the breakers once the equipment has been shutdown.**
   Follow the sub-system shutdown procedures.
9. **De-energize the fuel cell plant 208/120V normal power loads one at a time by opening the branch breakers in 600-LP-A.**
   Refer to the panel schedules on drawing number 437000-67K-20
10. **De-energize the fuel cell plant 480V loads one at a time by opening the breakers: CB-155A, 155B, 155D, 155E, 156A, 156B, 157B, 157C and 157D.**
    Refer to the one-line diagram 437000-67E-13.
11. **De-energize the fuel cell plant 120V UPS loads one at a time by opening the branch breakers in 600-LP-B.**
    Refer to the panel schedules on drawing number 437000-67K-20
12. **De-energize the DCS by opening the circuit breakers mounted in the bottom left corner of the DCS I/O panel.**
13. **De-energize the EBOP heating resistors, by opening breaker CB-158A.**
14. **De-energize the various EBOP systems and the air conditioner, by opening breakers CB-160B, 160C, 160D, 160E, 160F, 161A and 161J in lighting panel 600-LP-A.**
15. **De-energize the normal-power panel board 600-LP-A, by opening breaker CB-160A, then CB-155C.**
16. **Provide bypass power to the UPS, by opening breaker CB-156E, and then CB-156D.**
17. **De-energize the 480V auxiliary power bus, by opening the breaker CB-151B.**
18. **Open breaker CB-152A by pressing the OPEN switch on the breaker.**
19. **De-energize the 480V South Plant interconnection line in accordance with the King County procedures.**
20. **De-energize the EBOP control systems and critical loads in panel 600-LP-B, open breakers CB-165B, 165C, 165D, 165E, and 165H, then open breakers CB-165F, 165G, 165J and 165K.**
21. **Open CB-165A, the 50A main disconnect for 600-LP-B.**
22. **Turn off the UPS (600-U-101).**
    Follow the vender O&M or the UPS securing procedure.

Restoring power following a power failure

Use the procedure "Starting the electrical system" on page 6-88

Before starting the UPS

Before starting the UPS (Galaxy 3000), read this procedure and the Galaxy 3000 Users Manual thoroughly. Be certain that you fully understand the operation of the indicators, controls, and operational sequences.

- Be sure all power and control wires are properly connected and securely tightened.
- Check to see that the upstream and downstream protective devices are not tripped.
- Check that the input voltage is the same as indicated on the UPS nameplate, located inside the door of the Galaxy 3000 UPS module.
- Check that the air filters located inside each the UPS cabinet door are properly installed and free of dust, dirt and debris. Make certain that nothing is blocking the air intake underneath and around the front bottom of the UPS cabinet and that the air exhaust on the top of the UPS cabinet is free of all obstructions.
- Verify that the manual bypass switch SR-1 is set to the NORMAL.
- Check that the maintenance bypass circuit breakers CB-156D and
- CB-156E is set to OFF (open).
- Check that the battery disconnect circuit breaker QF-1 is set to OFF (open).
- Check that the cabinet is resting on its lifting levelers and not on the 4 wheels.
- Check that the 120V load-circuit breakers in 600-LP-B are set to OFF (open).

Starting the UPS

"Before starting the UPS" on page 6-91.

1. **Check that the internal maintenance bypass rotate switch (SR-1) is in the NORMAL position.**
2. **Set the Normal AC source input (CB-156C) to ON.**
3. **Wait 10 seconds while the circuits are initialized.**
4. **Set the battery circuit breaker QF-1 to the ON.**
5. **The UPS should now start automatically and display and LED will indicate LOAD IS PROTECTED BY THE UPS.**
6. **Close breaker CB-165A in 600-LP-B panel to energize UPS 120V loads bus.**
7. **Close the 120V load-circuit breakers as necessary.**

Testing the UPS

Have an electrician perform the following tests from the Galaxy 3000 O&M.

- Emergency power off (EPO) test.
- Remote emergency power off (REPO) test (if applicable).
- Inverter start and stop.
- Battery transfer test.

Shutting down the UPS

The UPS remains energized unless it is shut down.

1. **Turn off the UPS.**
   Press the OFF button on the UPS. Confirm by pressing the function key marked YES.
   - The UPS no longer protects the load. It is supplied via the bypass.
   - The charger no longer operates to keep the batteries fully charged.
2. **Turn off the battery charger**
   Set the battery circuit breaker (QF-1), to the OFF (open) position.

- *NOTE:To completely shutoff power to the UPS system, set breakers CB-156C, CB-156D, and CB-156E to OFF (open).*

Testing the UPS on 120 V loads in 600-LP-B

1. **Be sure that the internal maintenance bypass rotate switch (SR1) is in the BYPASS position.**
2. **Be sure the battery circuit breaker, (QF-1), is OFF (open).**
3. **Close the maintenance bypass breakers. AC source input breakers (CB-156D and CB-156E) are set to ON.**
4. **At this point, power should be available for the UPS 120V loads in 600-LP-B panel.**

Replacing the batteries

WARNING

Servicing batteries should be performed or supervised by personnel who understand batteries and the required precautions. Keep unauthorized personnel away from batteries.

Do not dispose of battery or batteries in a fire. The battery may explode.

Do not open or mutilate the battery or batteries. The electrolyte that is released is harmful to the skin and eyes. It may be toxic.

A battery can present a risk of electrical shock and high short-circuit current. The following precautions should be observed when working with batteries:

Remove watches, rings, or other metal objects.

Use tools with insulated handles.

Wear rubber gloves and boots.

Do not lay tools or metal parts on top of batteries.

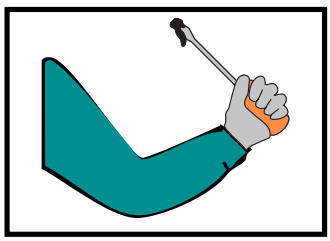
Disconnect charging source prior to connecting or disconnecting battery terminals.

WARNING

Determine if the battery is inadvertently grounded. If inadvertently grounded, remove the source of ground. Contact with any part of a grounded battery can result in electrical shock. The likelihood of such shock will be reduced if such grounds are removed during installation and maintenance

1. **Replace the batteries, using the same model and manufacturer.**

Reference



6.21 Miscellaneous Systems

There are several other critical systems which must be checked and started before the fuel cell system is ready to start. The DCS computer (DeltaV) and the two computer stations (App-Station and Pro-plus) must be running, the enclosure ventilation systems must be on to maintain temperatures inside the enclosures within normal limits, and the drainage system which must be working to prevent water puddle which could present slipping hazards. The fire alarm panel must also be working. The fire alarm panel uses the DCS computer to actuate safety measures on the system.

Operating the DeltaV computer

Starting up the Delta V software

1. **Be sure the EBOP has power and the controller is turned on.**
2. **Check power is on to the modem and hubs.**
3. **Turn on the Pro-plus computer**
   a) At the Pro-plus station, turn power ON
   b) Press CTRL-ALT-Delete
4. **Log on the Pro-plus computer.**
   Enter the following information:
   - User name – _____
   - Password – _____
5. **Log on to DELTAV**
   Enter the following:
   - Computer – KC2PPLUS
   - User name – _____
   - Password – _____
6. **Enable the FLEX LOCK.**
   Go to the NT desktop, from the START menu, select DELTAV, OPERATOR, and DELTAV OPERATE.
7. **Turn on the App-Station.**
   a) Turn power ON
   b) Press: CTRL-ALT-Delete
8. **Log on to the App-Station, enter the following information:**
   - User name – _____
   - Password – _____
9. **Log on to DELTAV, enter the following:**
   - Computer – KC2APPSTN
   - User name – _____
   - Password – _____
10. **Enable the FLEX LOCK.**
    a) Go to the NT desktop, from the START menu, select DELTAV, ENGINEERING, FLEX LOCK
    b) From FLEX LOCK: select OPERATOR INTERFACE

Shutting down the Delta V computer

1. **Shut down the Pro-plus station.**
   a) Close the DELTAV OPERATE
   b) Close the DELTAV EXPLORER
   c) Close any programs that remain open
   d) Select START, and then SHUTDOWN
2. **Shut down the App-Station**
   a) Close the DELTAV OPERATE
   b) Close EXCEL
   c) Close any programs that remain open
   d) Select START, and then SHUTDOWN

Operating the fire alarm panel

The panel must have power, verify breaker CB-161B in 600-LPA is closed.

Verify communication to the DCS by verifying that the FIRE PROTECTION SYSTEM TROUBLE alarm (UA-001) is NORMAL on the Emergency Shutdown Screen.

Operating the ventilation systems

There are three ventilation systems, one in the anode fuel gas preparation system enclosure for the desulfurizers, one for the water treatment

system enclosure, and one in the digester gas preparation system enclosure.

Before starting the ventilation equipment

1. **Check that the instrument and control circuits are energized**
2. **Check that power is supplied (CB9 and CB1 closed)**
3. **Check that the 480V auxiliary power bus is energized**
4. **Check that all the louvers on fans are free to move and not blocked or clogged with debris.**
5. **Check that the space heaters hot surfaces are not in contact with other equipment or combustible materials.**
6. **Check that all equipment is properly assembled, and that all electrical and control systems are restored from prior maintenance. Check that all administrative procedures connected with the maintenance activity have been completed.**

Starting up the ventilation equipment

1. **Check that the breakers are closed for the desulfurizer enclosure heater (CB161G) and the water treatment enclosure heater (CB161H).**
2. **Check that the desulfurizer enclosure heater is set to maintain at least 60°F.**
   Adjust the adjust temperature setting using the dials on the side of the heater, as necessary
3. **Check that the water treatment enclosure heater is set to maintain at least 40°F.**
   Adjust the adjust temperature setting using the dials on the side of the heater, as necessary.
4. **Start the desulfurizer enclosure fans.**
   Turn the primary fan ON/OFF switch to ON and the secondary fan HAND/OFF/AUTO switch to AUTO. Both fans may come on at first, but once flow is established on the primary sensor, the secondary fan should shut off.
5. **Start the digester gas compressor enclosure ventilation fan.**
   Close the breaker on the compressor PLC panel and then start the fans.

Operating the drainage systems

There is no sump system in the fuel cell area, the drains flow by gravity to the South Plant headworks. Reject/regeneration/backwash water from the water treatment system are disposed into the plant sewer system.

The digester gas preparation system uses cooling water to cool the digester gas in the digester gas aftercooler which is dumped to an open sewer. The process condensate that is made in the digester gas conditioning system drains into a closed sewer. This water contains oil from the digester gas compressor and trace sulfur from the digester gas. Both sewers will return the effluent to the plant headworks.

Before starting the drainage system

1. **Be sure all the drain funnels are clean and that no accumulated debris could plug the drains.**
2. **Be sure that no volatile chemicals or flammable liquids have been inadvertently dumped in the drains**
   Be sure all maintenance work is finished, all equipment is fully assembled and tested, and that all administrative procedures connected with the maintenance activity have been completed.
3. **Verify that all closed sewer access openings are closed**

Starting up drainage

1. **Open any drain isolation valves that may be installed in the drainage system.**

Starting the instrument air system

To be provided. See the initial valve lineup on the next page.

KCPP DFC1500-1 Instrument air system pre-startup valve lineup

Valve	Description	Position	Notes
MV-501	Air Compressor #1 Outlet Valve	SHUT	
MV-539	IA Isolation to FV-117/800	OPEN	
PT-501 Root		OPEN	
MV-3010	AE-342 A/B AIR SUPPLY LOW POINT DRAIN	OPEN	
MV-502	Air Compressor #2 Outlet Valve	SHUT	
MV-3011	AE-342 A/B AIR INLET LOW POINT DRAIN	OPEN	
MV-503	FL-501 Inlet Valve	OPEN	
MV-504	FL-502 Inlet Valve	OPEN	
MV-505	FL-501/FL-502 Bypass	SHUT	
MV-506	FL-501 Outlet Valve	OPEN	
MV-507	FL-502 Outlet Valve	OPEN	
MV-508	Air Dryer #2 Inlet Valve	SHUT	
MV-509	Air Dryer #1 Inlet Valve	SHUT	
MV-510	Air Dryer #2 Outlet Valve	SHUT	
MV-511	Air Dryer #1 Outlet Valve	SHUT	
MV-512	FL-503 Inlet Valve	OPEN	
MV-513	FL-504 Inlet Valve	OPEN	
MV-514	FL-503/FL-504 Bypass Valve	SHUT	
MV-515	FL-503 Outlet Valve	OPEN	
MV-516	FL-504 Outlet Valve	OPEN	
MV-517	#1 500 Gallon Air Receiver Inlet	OPEN	
MV-518	#2 500 Gallon Air Receiver Inlet	OPEN	
MV-519	Air Compressor #1 Drain Valve	OPEN	
MV-520	Air Compressor #2 Drain Valve	OPEN	
MV-521	Electrical Enclosure Air Supply Vent	OPEN	
MV-522	80 Gallon Air Receiver Auto Drain Valve Inlet	OPEN	
MV-523	80 Gallon Air Receiver Auto Drain Valve Outlet	OPEN	
MV-524	80 Gallon Air Receiver Auto Drain Bypass	OPEN	
MV-525	FL-501 Auto Drain Valve Inlet	OPEN	
MV-526	FL-501 Auto Drain Valve Outlet	OPEN	
MV-527	FL-501 Auto Drain Valve Bypass	OPEN	
MV-528	FL-502 Auto Drain Valve Inlet	OPEN	
MV-529	FL-502 Auto Drain Valve Outlet	OPEN	
MV-530	FL-502 Auto Drain Valve Bypass	OPEN	
MV-531	80 Gallon Air Receiver Inlet Valve	OPEN	
MV-532	80 Gallon Air Receiver Outlet Valve	OPEN	

KCPP DFC1500-1 Instrument air system pre-startup valve lineup

Valve	Description	Position	Notes
MV-533	Instrument Air Header Supply	OPEN	
MV-534	FL-501/FI-502 Inlet Root	OPEN	
MV-535	Condensate Drain Bottom Of Skid	OPEN	
MV-536	Condensate Drain Side Of Side	OPEN	
MV-537	Electrical Enclosure Purge Air Isolation	SHUT	
MV-538	#1 500 Gallon Air Receiver Vent	SHUT	
MV-1043A	IA To XV-103A	OPEN	
MV-1043B	IA To XV-103B	OPEN	
MV-1043	IA Supply To NG Safety Shutoff Valves	OPEN	
MV-2025	IA Spare	SHUT	
MV-1056	IA Header Vent	SHUT	
PT-501-Root	IA Pressure Transmitter (PT-501) Isolation	OPEN	
PI-265 Root	IA to Oxidizer Pilot Pressure Gage Isolation	OPEN	
MV-2017	IA To XV-214	OPEN	
MV-2019B	IA To XV-205	OPEN	
MV-2013	IA To XV-220	OPEN	
MV-2021	IA To FV-208A	OPEN	
MV-2019A	IA To XV-203	OPEN	
MV-2016	IA To XV-212	OPEN	
MV-2012	Air Supply Oxidizer Pilot	OPEN	
MV-2023	IA To FV-208B	OPEN	
PI-262 Root	IA Header Pressure Gage Isolation	OPEN	
MV-2011	IA Header Isolation	OPEN	
MV-IA-CG	IA to Cover Gas Panel Pressurization	OPEN	
MV-IA-XV-247A	IA to XV-247A	OPEN	
MV-IA-XV-247B	IA to XV-247B	OPEN	
MV-IA-XV-262	IA to XV-262	OPEN	
MV-IA-XV-260	IA to XV 260	OPEN	
MV-2014	IA Low Point Drain	SHUT	
MV-2024	IA To VFD Panel	OPEN	
MV-2022	IA To FV-230	OPEN	
MV-2020	IA To FV-210	OPEN	
MV-2018	IA To TV-245	OPEN	
MV-2015	IA To XV-241	OPEN	
MV-2001	10# IA To Oxidizer	OPEN	
MV-1057	IA To Desulfurization Skid	OPEN	

KCPP DFC1500-1 Instrument air system pre-startup valve lineup

Valve	Description	Position	Notes
MV-1059	IA To Oxidizer	OPEN	
MV-1058	IA Header Isolation	OPEN	
MV-IA-XV-284	IA to XV-284	OPEN	
MV-IA-FV-131	IA to FV-131	OPEN	
MV-IA-XV-191	IA to XV-191	OPEN	
MV-IA-FV-117	IA to FV-117	OPEN	
MV-IA-XV-282	IA to XV-282	OPEN	
MV-IA-XV-280	IA to XV-280	OPEN	
MV-IA-LEL	IA to LEL Detector	OPEN	

Starting the digester gas conditioning system

Normally once the compressors are in AUTO the system starts and is operated by the DCS. The following is the initial valve line up for the system.

KCPP DFC1500-1 Anaerobic digester gas (ADG) system startup, polisher A to B pre-startup valve lineup

Valve	Description	Position	Notes
	POLISHER "A" MID-BED SAMPLE	SHUT	
	POLISHER "A" OUTLET SAMPLE	SHUT	
	POLISHER "B" MID-BED SAMPLE	SHUT	
	POLISHER "B" OUTLET SAMPLE	SHUT	
	HE OIL FILTER OUTLET SAMPLE	SHUT	
	SULFATREAT VESSEL OUTLET SAMPLE	SHUT	
MV-8216	Main Isolation LV830	OPEN	
MV-8217	Main Isolation LV828	OPEN	
FE-800	ADG GAS FLOWMETER	SHUT	
MV-8076	SULFATREAT VESSEL OUTLET SAMPLE	SHUT	
LV-824	ADG INLET KNOCKOUT DRUM LEVEL DRAIN LOW	AUTO	
FCV-812	Nitrogen purge regulator to polishers	SHUT	
MV-8077	POLISHER "A" OUTLET SAMPLE VALVE	SHUT	
LV-826	ADG DISCHARGE KNOCKOUT DRUM LEVEL DRAIN HIGH	AUTO	
MV-8067	PDI-822 HIGH SIDE ISOLATION	OPEN	
MV-8078	POLISHER "A" MID-BED SAMPLE VALVE	SHUT	
LV-825	ADG INLET KNOCKOUT DRUM LEVEL DRAIN HIGH	AUTO	
LV-827	ADG DISCHARGE KNOCKOUT DRUM LEVEL DRAIN LOW	AUTO	
MV-8079	POLISHER "B" OUTLET SAMPLE VALVE	SHUT	
MV-8068	PDI-822 LOW SIDE ISOLATION	OPEN	
MV-8080	POLISHER "B" MID-BED SAMPLE VALVE	SHUT	

KCPP DFC1500-1 Anaerobic digester gas (ADG) system startup, polisher A to B pre-startup valve lineup

Valve	Description	Position	Notes
FV-800	ADG GAS FLOW CONTROL VALVE	HANDWHEEL BACKED OUT	
LV-828	ADG OIL FILTER LOWER LEVEL CONTROLLER	AUTO	
MV-8081	HE OIL FILTER OUTLET SAMPLE	SHUT	
MV-8070	PDI-804 HIGH SIDE ISOLATION	OPEN	
MV-8071	PDI-804 LOW SIDE ISOLATION	OPEN	
LV-830	ADG OIL FILTER UPPER LEVEL CONTROLLER	AUTO	
MV-8072	PDI-806 HIGH SIDE ISOLATION	OPEN	
MV-8073	PDI-806 LOW SIDE ISOLATION	OPEN	
MV-8002	ADG INLET LINE DRAIN/VENT	SHUT	
MV-8082	HE Oil Filter Drain	SHUT	
MV-8003	ADG INLET KNOCKOUT DRUM MANUAL DRAIN	SHUT	
MV-8075	PDI-812 LOW SIDE ISOLATION	OPEN	
MV-8004	ADG COMPRESSOR LUBRICATOR DRAIN	SHUT	
MV-8026	PI-808 Gauge vent line drain	SHUT	
MV-8005	ADG COMPRESSOR INLET DRAIN/VENT	SHUT	
MV-8038	ADG Inlet Strainer drain	SHUT	
MV-8006	ADG COMPRESSOR MANUAL CASING DRAIN	SHUT	
MV-8040	Compressor Oil seal pot drain	SHUT	
MV-8007	ADG COMPRESSOR DISCHARGE DRAIN/VENT	SHUT	
MV-8059	ADG Afterfilter Bypass	SHUT	
MV-8008	ADG AFTERCOOLER DISCHARGE COOLING WATER SAMPLE/DRAIN	SHUT	
MV-8029	Compressor cooling water isolation	OPEN	
MV-8201	Instrument Air to ADG Skid Isolation	OPEN	
MV-8009	ADG OUTLET KNOCKOUT DRUM MANUAL DRAIN	SHUT	
MV-8202	Instrument Air to HE Oil Filter COntroller Main Isolation	OPEN	
MV-8010	ADG COMPRESSOR COOLING WATER FLOW CONTROL VALVE OUTLET ISOLATION	OPEN	
MV-8203	Instrument Air to HE Oil filter Lower Controller Isolation	OPEN	
MV-8011	ADG COMPRESSOR COOLING WATER FLOW CONTROL VALVE INLET ISOLATION	OPEN	
MV-8012	ADG COMPRESSOR COOLING WATER FLOW CONTROL VALVE MANUAL BYPASS	SHUT	
MV-8204	Instrument Air to HE Oil filter Upper Controller Isolation	OPEN	
MV-8001	ADG INLET MANUAL ISOLATION	locked/ tagged open	

KCPP DFC1500-1 Anaerobic digester gas (ADG) system startup, polisher A to B pre-startup valve lineup

Valve	Description	Position	Notes
MV-8205	Instrument Air to Quick Disconnect Main Isolation	OPEN	
MV-8015	ADG MAIN COOLING WATER FLOW CONTROL MANUAL BYPASS	SHUT	
MV-8013	ADG MAIN COOLING WATER FLOW CONTROL OUTLET ISOLATION	OPEN	
MV-8206	Instrument Air to Quick Disconnect connection lower	OPEN	
MV-8064	ADG GAS FLOW CONTROL VALVE OUTLET MANUAL ISOLATION	OPEN	
MV-8042	ADG POLISHER A MANUAL DRAIN	SHUT	
XV-800A	ADG to AT-100 Solenoid In	not overridden	
MV-8014	ADG MAIN COOLING WATER FLOW CONTROL INLET ISOLATION	OPEN	
MV-8043	ADG POLISHER A PURGE ISOLATION	SHUT	
XV-800B	ADG to AT-100 Solenoid Out	not overridden	
MV-8065	ANALYZER ADG GAS INLET MANUAL ISOLATION	OPEN	
MV-8207	Instrument Air to Quick Disconnect connection upper	OPEN	
MV-8066	ANALYZER ADG GAS OUTLET MANUAL ISOLATION	OPEN	
MV-8016	ADG MAIN CONDENSATE DRAIN HEADER ISOLATION	OPEN	
MV-8044	ADG POLISHER B PURGE ISOLATION	SHUT	
MV-8208	Instrument Air to ADG Block valves Main Isolation	OPEN	
PCV-840	ADG COMPRESSOR NITROGEN SEAL REGULATOR	THROTTLED OPEN	
MV-8045	ADG POLISHER B MIDPOINT SAMPLE ISOLATION	OPEN	
MV-8209	Instrument Air to XV-820A Isolation	OPEN	
PSV-801	ADG INLET KNOCKOUT DRUM RELIEF 50PSI	not overridden	
MV-8047	ADG POLISHER B MANUAL DRAIN	SHUT	
MV-8017	ADG OIL FILTER INLET ISOLATION	OPEN	
PSV-805	ADG POLISHER A DISCHARGE PRESSURE RELIEF 50PSI	not overridden	
MV-8020	ADG OIL FILTER OUTLET ISOLATION	OPEN	
PSV-815	ADG OUTLET KNOCKOUT DRUM RELIEF 50PSI	not overridden	
PSV-816	ADG SULFATREAT VESSEL PRESSURE RELIEF 50PSI	not overridden	
MV-8210	Instrument Air to XV-820B Isolation	OPEN	
MV-8048	ADG POLISHER B SAMPLE ROOT ISOLATION	OPEN	
PSV-825	ADG COMPRESSOR DISCHARGE RELIEF 55 PSI	not overridden	
MV-8211	Instrument Air to XV-801 Cooling Water Regulator	OPEN	
MV-8051	ADG POLISHER B OUTLET CROSSOVER ISOLATION	SHUT	
PV-819	ADG COMPRESSOR RECIRC REGULATOR	AUTO	

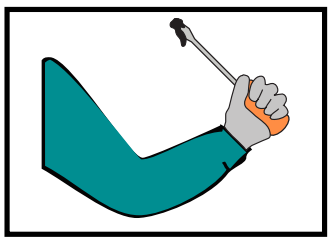
KCPP DFC1500-1 Anaerobic digester gas (ADG) system startup, polisher A to B pre-startup valve lineup

Valve	Description	Position	Notes
MV-8018	ADG OIL FILTER MANUAL VENT	SHUT	
TCV-831	ADG COMPRESSOR COOLING WATER TEMPERATURE FLOW CONTROL VALVE	AUTO	
MV-8021	ADG OIL FILTER DISCHARGE SAMPLE ISOLATION	SHUT	
PDI-810-HP Root		OPEN	
TCV-833	ADG COMPRESSOR AFTERCOOLER TEMPERATURE FLOW CONTROL VALVE	AUTO	
XV-801	ADG COOLING WATER MAIN SUPPLY REGULATOR	handwheel backed out	
MV-8022	ADG NITROGEN PURGE INLET ISOLATION	SHUT	
MV-8074	PDI-812 HIGH SIDE ISOLATION	AUTO	
XV-820A	ADG MAIN GAS INLET ISOLATION A	AUTO	
XV-820B	ADG MAIN GAS INLET ISOLATION B	AUTO	
PDI-810-LP Root		OPEN	
PDI-827 Root		OPEN	
MV-8023	ADG NITROGEN PURGE HEADER ISOLATION	SHUT	
MV-8024	ADG SULFATREAT VESSEL RELIEF HEADER SAMPLE RETURN ISOLATION	SHUT	
PDI-827-HP Root		OPEN	
MV-8025	ADG WATER HOSE COUPLING ISOLATION	SHUT	
PDI-828-HI Root		OPEN	
PDI-828-LO Root		OPEN	
MV-8027	ADG SULFATREAT VESSEL MANUAL DRAIN	SHUT	
PDISH-827 Root		OPEN	
MV-8028	ADG SULFATREAT VESSEL DISCHARGE SAMPLE ISOLATION	SHUT	
PDISH-827-HP Root		OPEN	
PDISH-828-HI Root		OPEN	
MV-8030	ADG SULFATREAT VESSEL DISCHARGE VENT VALVE	SHUT	
PDISH-828-LO Root		OPEN	
PI-807 Root		OPEN	
MV-8031	ADG SULFATREAT VESSEL DISCHARGE VENT ISOLATION	SHUT	
PI-809 Root		OPEN	
MV-8032	ADG SULFATREAT VESSEL DISCHARGE ISOLATION	OPEN	
PI-817 Root		OPEN	
MV-8033	ADG POLISHERS MAIN VENT ISOLATION	SHUT	
MV-8035	ADG POLISHER B INLET ISOLATION	SHUT	

KCPP DFC1500-1 Anaerobic digester gas (ADG) system startup, polisher A to B pre-startup valve lineup

Valve	Description	Position	Notes
PI-820 Root		OPEN	
MV-8034	ADG POLISHER A INLET ISOLATION	OPEN	
PI-821 Root		OPEN	
PI-823 Root		OPEN	
PI-826 Root		OPEN	
MV-8050	ADG POLISHER A OUTLET CROSSOVER ISOLATION	OPEN	
MV-8053	ADG POLISHER B OUTLET ISOLATION	OPEN	
PI-833 Root		OPEN	
MV-8052	ADG POLISHER A OUTLET BYPASS ISOLATION	SHUT	
MV-8057	ADG AFTERFILTER INLET ISOLATION	OPEN	
MV-8054	ADG PURGE REGULATOR INLET ISOLATION	SHUT	
MV-8062	ADG AFTERFILTER OUTLET ISOLATION	OPEN	
PSH-831 Root		OPEN	
MV-8036	ADG POLISHER A VENT ISOLATION	SHUT	
MV-8055	ADG PURGE REGULATOR OUTLET ISOLATION	SHUT	
MV-8037	ADG POLISHER B VENT ISOLATION	SHUT	
MV-8056	ADG PURGE LINE NITROGEN INLET ISOLATION	SHUT	
MV-8058	ADG AFTERFILTER DRAIN	SHUT	
PSV-811	Polisher B Relief valve	not overridden	
MV-8060	ADG AFTERFILTER HEAD VENT	SHUT	
PT-818 Root		OPEN	
PT-819 Root		OPEN	
MV-8039	ADG POLISHER A SAMPLE ISOLATION	OPEN	
MV-8061	ADG AFTERFILTER CASING VENT	SHUT	
MV-8063	ADG COROLIS FLOWMETER OUTLET DRAIN/VENT	SHUT	
MV-8041	ADG POLISHER A MIDPOINT SAMPLE ISOLATION	OPEN	
LY-828	HE Oil Filter Lower level controller	not overridden	
LY-830	HE Oil Filter Upper level controller	not overridden	
MV-8069	PI-800 ISOLATION	OPEN	
MV-8212	High Isolation LC830	OPEN	
MV-8213	Low Isolation LC830	OPEN	
MV-8214	High Isolation LC828	OPEN	
MV-8215	Low Isolation LC828	OPEN	

Reference



6.22 Initial Valve Lineup Checklist

This list is used before starting the fuel cell system, the instrument air system, the water system, the digester gas preparation system, and the nitrogen system also have pre-startup valve lineup lists. A copy of these checklists is included in Appendix A. Electronic versions are also available upon request from Technical Publications.

KCPP DFC1500-1 Plant pre-startup valve lineup

Valve	Description	Position	Notes
Proprietary information— Not Available for Publication.			

KCPP DFC1500-1 Plant pre-startup valve lineup

Valve	Description	Position	Notes

KCPP DFC1500-1 Plant pre-startup valve lineup

Valve	Description	Position	Notes

KCPP DFC1500-1 Plant pre-startup valve lineup

Valve	Description	Position	Notes
Proprietary information— Not Available for Publication.			

KCPP DFC1500-1 Plant pre-startup valve lineup

Valve	Description	Position	Notes

Reference

APPENDIX 1
Index

Symbols

<%nopage>Water system
See water treatment system 5-22

A

Above 700°F
gas and water flow 6-3
ACG
See anode cover gas
Acknowledging alarms 1-15
Activated carbon filter 5-22
ADG
anaerobic digester gas, See digester gas
Aftercooler
digester gas compressor 5-27
Afterfilter
replacing desulfurizer filter 6-76
AGO blower
air flow control 5-14
before starting 6-82
control 5-5
during power generation 5-14
fuel-to-air ratio, se air flow control 5-14
AGO burner
before starting 6-82
control strategy 5-4
controls 5-14
fuel flow control 5-14
fuel flow isolation 5-14
operators notes, see main burner 6-4
pilot fails, see Note in step 15 6-50
response to power generation 6-4
screen, illustration 5-15
starts cycling 6-3
AGO response to power generation 5-15
AGO skid
purging natural gas distribution 6-83
AGO system
before starting 6-82
emergency shutdown 6-83
shutting down rapidly 6-83
starting 6-82
Alarm beacon
locations 3-4
Alarms
acknowledging 1-15
DCS list 4-6
local burner management system 4-17
local digester gas preparation 4-16
local startup skid 4-18
water treatment 5-25
water treatment system, local 5-24
Anaerobic digester gas
See digester gas
Analyzer 5-12
anode fuel preparation 5-12
carbon content 5-12
Anode 1-6
Anode cover gas 5-21
control 5-8, 6-10
makeup 6-10
operators notes 6-10
overview 1-9
Rapid Restart 6-49
Anode fuel flow
control 5-5
Anode fuel gas
supply and isolation 5-12
Anode fuel preparation
analyzer 5-12
analyzer alarms 5-12
deoxidizer 5-13
desulfurizer bed life 5-12
desulfurizers 5-12
gas heater 5-12
humidifier 5-12
inlet flow control 5-12
supply block/isolation valves 5-13
Anode gas oxidizer
design rating 1-6
overview 1-6
See also AGO
Anode outlet-to-cathode outlet differential
see stack pressure 5-16
Anti-scalant 5-22
App-Station
logging on 1-16
shutting down 1-16
turning on 1-15

B

Bed life
desulfurizers 5-12
SulfaTreat 5-9
Before starting
AGO system 6-82
Below 286°F
cooling down 6-58
Bleed
nitrogen 5-21
Block valves
anode fuel supply 5-13
Burner gas feed isolation
control 5-5
Burner management system
control panel illustration 1-13
Burner management system local alarms 4-17
Buttons, computer screen defined 1-14

C

Calibration gas
overview 1-9
Carbon content
analyzer 5-12
Carbon media
desulfurizer 6-74
Catalyst chemical reaction temperature
see catalyst section temperature 5-15
Catalyst section temperature control 5-15
Cathode exhaust 5-15
LEL 5-15
Cell group voltage deviation
operators notes 6-12
Cell group voltages 5-17
Cell voltage
how measured 6-12
Changing
desulfurizer lead and guard positions 6-66
Grid power generation to HOT STANDBY 6-40
HEATUP-1 to HEATUP-2(NG) 6-17
HEATUP-2 NG to HEATUP-3 NG 6-19
HEATUP-3 NG to HEATUP-4 NG 6-20
HEATUP-4 NG to HOT STANDBY NG 6-21
HOT RESTART to HEATUP-2(NG) 6-17
HOT STANDBY to Grid Power Generation 6-34
IDLE to HEATUP-1 NG 6-16
SHUTDOWN to IDLE 6-15
Checks
daily start-up skid 2-13
daily, digester gas prepartions skid 2-16
daily, EBOP 2-14
daily, fuel preparation area 2-6
daily, skid 1 2-4
daily, skid 2 side A 2-10
daily, skid 2 side B 2-10
daily, skid 2 side C 2-12
daily, water treatment area 2-8
Cleaning
digester gas control 5-8
Cold start 5-4
Cold start NG
assessing 6-14
Compressor
See instrument air or digester gas
Computer
App-Station 1-15, 1-16
operating DeltaV 6-94
See distributed control 1-14
See operator interface unit 1-14
Confined spaces 2-3, 3-3
Continuous deionization
see deionizationCDI
See deionization, continuous
Cool down 1
description 5-34
Cooldown 2
description 5-34
Cooldown 3
description 5-34
Cooldown from hot standby 5-34
Cooldown-1 to Cooldown-2
cooling down 6-55
Cooldown-2 to Cooldown-3
cooling down 6-56
Cooling down
below 286°F 6-58
Cooldown-1 to Cooldown-2 6-55
Cooldown-2 to Cooldown-3 6-56
Heatup-2 to Cooldown-3 6-56
Heatup-3 to Cooldown-2 6-55
Heatup-4 to Cooldown 1 NG/DG 6-54
Hot Standby to Cooldown 1 NG/DG 6-54
Cover gas
anode 5-21
Current power level, see DC power 5-18

D

Daily checks

digester gas prepartions skid 2-16
EBOP 2-14
fuel preparation area 2-6
skid 1 2-4
skid 2, side A 2-10
skid 2, side B 2-10
skid 2, side C 2-12
start-up skid 2-13
water treatment area 2-8
DCS
App-Station 1-16
operating DeltaV 6-94
See distributed control
Deionization 5-22
Deionized water
transfer pumps 5-24
Deionized water storage tank 5-23
DeltaV
computer 1-15
logging on 1-15
operating computer 6-94
see monitoring dV/cell 6-13
shutting down 1-16
Demanded gross AC power
see calculated set points 5-19
Demanded ICD
see DC power 5-18
Deoxidizer
anode fuel preparation 5-13
Desulfurizer
anode fuel preparation 5-12
bed life 5-12
changing lead and guard positions 6-66
control 5-5
enclosure control 5-5
one online 6-66
purging 6-64, 6-70
purging both 6-71
putting back in service 6-68
replacing afterfilter filter 6-76
replacing carbon media 6-74
Desulfurizer A
purging 6-70
Desulfurizer B
purging 6-71
DG
See digester gas
DI
See deionization
Differential temperature
defined 1-12
Digester gas
cleaning control 5-8
compressor control 5-8
compressor cooling 5-27
compressor enclosure 5-26
control panel, illustration 5-29
discharge knockout drum 5-27
jacket water 5-27
knockout drum 5-26
oil filter 5-27
polisher A to B pre-startup valve lineup 6-98
polishers control 5-8
raw supply valves 5-26
screens 5-28
startup valve lineup 6-98
Digester gas compressor
aftercooler 5-27
rating 1-8
Digester gas conditioning
description 5-26
Digester gas knockout drums
control 5-8
Digester gas polishers 5-27
Digester gas preparation
control panel illustration 1-13
emergency monitoring 1-24
layout illustration and photos 1-24
local alarms 4-16
overview 1-8
Discharge knockout drum 5-27
Distributed control
DeltaV computer 1-15
starting computer 1-15
Drainage
operating systems 6-95
dV
See voltage deviation

E

EBOP
See electrical balance of plant
Effluent streams, handling 1-18
Electrical
classification 2-2
lethal voltage areas 2-3
Electrical balance of plant
enclosure 5-18
overview 1-8
securing 6-89

Electrical classification 3-2
Electrical conditioning
monitoring 5-18
system enclosure 5-18
Electrical production
fuel cell design specifications 1-5
Emergency monitoring
digester gas preparation 1-24
Emergency shutdown
buttons, locations 1-20
fire and gas alarms 4-3
location photos 3-4
locations 3-4
required screen prints table 6-45
responsibility 2-2, 3-2
three plant responses 6-7
what to do 6-6
Enabling
fuel cell for startup 5-30
gas and water, critical 6-3
process and utilities 5-30
Enclosure
electrical 5-18
operating fans 6-94
water system 5-22
End cells
see note under halting power ramp up 6-12
ESD
See emergency shutdown
Explosive gas monitoring
See LEL

F

Faceplates
using 1-15
Fail message trip
reset 4-5
Fans
operating 6-94
FCE
See Fuel Cell Energy
Fire alarm panel
operating 6-94
power 1-16
power supply 6-94
Fire alarm system 5-20
First-out trip
reset 4-5
shutdown screen illustration 5-35
Forney alarms 1-12
Freeze protection 1-20
Fresh air blower
See AGO blower
Fuel cell
enabling for startup 5-30
layout drawing 1-21
layout photo 1-22
layout, detailed drawing 1-23
locking out after producing power 6-90
lockout out electrical 6-89
pre-startup valve lineup table 6-104
restoring power after outage 6-91
securing electrical 6-89
shutdown using hardwire button 5-34
shutdown valve table 5-35
shutdown, description 5-34
startup preconverter jacket heater, see in general 6-2
Fuel Cell Energy
operator's role 1-12
Fuel cell stack
air flow control 5-4
design specifications, electrical 1-5
fuel distribution monitoring 5-16
Fuel flow vs current draw, see fuel flow rate 5-17
fuel gas flow 5-16
health, see voltage 5-17
overview 1-7
pressure 5-16
screens, illustration 5-17
temperature 5-16
temperature control 5-4
voltage 5-16
voltage screens, illustrations 5-17
Fuel flow set point
fuel cell stack 5-17
Fuel flow vs current draw, see fuel flow rate 5-17
Fuel gas flow
fuel cell stack 5-16
Fuel gas preparation
system overview 1-6
Fuel preparation
before starting 6-62
shutting down the system 6-63
starting the system 6-62
Fuel superheater
control 5-5
purpose 5-13
Fuel utilization set point, see fuel flow rate 5-17

Fuel-steam mixture temperature
control 5-12
Fuel-to-air ratio
AGO blower, see air flow control 5-14
Full load mode 6-4

G

Gas and water
above 700°F 6-3
Gas flow without water
what to do 6-3
Gas polisher
bed life 5-9
Grid connect mode 6-4
Grid power generation to HOT STANDBY
changing 6-40

H

H2S
See hydrogen sulfide
Halting power ramp up
for dV/cell 6-12
Heat recovery system
overview 1-7
Heat tracing
instrument air 5-20
leaving superheater 5-13
Heatup
monitoring oxidant temperature 6-3
monitoring, operators notes 6-3
Heatup 1
description 5-32
halts 4-2
operators notes 6-2
Heatup 2
description 5-32
operators notes 6-2
what must happen before 6-2
Heatup 2 through 4 halts 4-2
Heatup 3
description 5-32
four-hour hold/soak 6-3
operator notes 6-3
Heatup 4
description 5-32
operators notes 6-4
tertiary valve 6-4
Heatup and cooldown
diagram 5-2
explanation 5-2
Heatup ramp hold 4-2
HEATUP-1 to HEATUP-2(NG)
changing 6-17
HEATUP-1 to HOT RESTART
changing 6-17
HEATUP-2 NG to HEATUP-3 NG
changing 6-19
Heatup-2 to Cooldown-3
cooling down 6-56
HEATUP-3 NG to HEATUP-4 NG
changing 6-20
Heatup-3 to Cooldown-2
cooling down 6-55
HEATUP-4 NG to HOT STANDBY NG
changing 6-21
Heatup-4 to Cooldown 1 NG/DG
cooling down 6-54
High efficiency oil filter 5-27
control 5-8
Hot Restart
description 5-36
initial conditions 6-46
operators notes 6-2
plant settings table 6-47
preparing for 6-46
procedure 6-46
shifting to 6-46
Hot Standby
description 5-32
operators notes 6-4
step down 4-3
Hot Standby to Cooldown 1 NG/DG
cooling down 6-54
HOT STANDBY to Grid Power Generation
changing 6-34
Hot Standby to Grid Power Generation
changing 6-34
Hot work 2-3, 3-3
Humidifier
anode fuel preparation 5-12
control 5-5
HVAC
operating 6-94
Hydrogen sulfide
meters required 1-24
see fire alarm system 5-20
SulfaTreat detector 5-27

I

IDLE to HEATUP-1 NG
changing 6-16

Instrument air
control 5-9
control strategy 5-20
design rating 1-9
design specifications 5-20
equipment 5-20
overview 1-9
pre-startup valve table lineup 6-96
Inverters 5-18
Isolation valves
anode fuel supply 5-13

J

Jacket water flow 5-27
Jelcleer filter 5-22

K

King County responsibilities 2-2, 3-2
Knockout drum 5-26

L

LAP 21
alarms 1-12
location 1-12
LEL
cathode exhaust 5-15
fuel cell stack 5-16
meter locations 1-20
see fire alarm system 5-20
SulfaTreat vessel 5-27
Load reduction to hot standby
description 5-33
Lockout
electrical balance of plant 6-89
Lower explosive level
See LEL
Low-pressure sludge gas
remote valve location 5-5
LSG
See low-pressure sludge gas

M

Main burner requirements
see burner control 5-15
Maintenance nitrogen 5-21
Manual shutdown 4-5
locations 4-5
MCFC see Molton carbonate fuel cell
Mixed-bed dionization
see polishing units 5-23
MOD BUS alarms
water treatment 5-25
Mode checklist
using, see note in Hot Restart 6-2
Molten carbonate fuel cell
chemical reactions 1-4
how constructed 1-4
Monitoring
fuel distribution 5-16
oxidant temperature 6-3

N

N2
See nitrogen
Natural gas distribution
purging AGO skid 6-83
Natural gas heater 5-12
control 5-5
Natural gas vs. digester gas defined 1-5
NetAC power target
see DC power 5-18
NGD
See natural gas desulfurized
Nitrogen
before starting 6-78
bleed 5-21
bleed control 5-8
changing rapid purge six-pack 6-79
changing slow purge six-pack 6-79
disconnecting slow purge six-pack 6-79
disconnecting the rapid purge sixpack 6-79
for maintenance 5-21
gas supply 5-20
pre-startup valve lineup table 6-80
purge control 5-8, 5-20
purge on emergency shutdown 6-11
purge on normal shutdown 6-11
purge, operators notes 6-10
purging both desulfurizers 6-71
purging desulfurizer 6-70
purging desulfurizer A 6-70
purging desulfurizer B 6-71
purging desulfurizers 6-64
purging preconverter 6-70, 6-72
purging system overview 1-8
starting rapid purge 6-78
starting slow purge 6-78

O

OIU
See operator interface unit
Operator interface unit
acknowledging alarms 1-15

buttons 1-14
navigating 1-14
transition checklists 1-14
using faceplates 1-15
using the interface 1-14
Overview screen 5-35
Oxidant supply system
control 5-4
Oxidizer
see AGO burner
Oxidizer blower
See AGO blower
Oxidizer catalyst section
control 5-4
Oxidizing the catalyst
see anode cover gas 6-10

P

PCS
See power conversion system
Peak shave gas
oxygen, see deoxidizer 5-13
see analyzer 5-12
Pilot
fails, see Note in step 15 6-50
instrument air requirements
see burner control 5-15
Plant settings table
Hot restart 6-47
Trip recovery 6-45
trip recovery 6-45
Plant shutdown
Fuel cell shutdown 6-54
Polishing units 5-23
Power conditioning 5-18
Power conversion system constant
see grid connect mode 6-4
Power failure
fuel cell NOT on line 6-88
Restoring power after outage 6-91
starting the electrical system
Electrical
starting the system 6-88
Power generation
AGO burner response 6-4
changing power level 6-37
changing to 6-4
description 5-33
Full load mode 6-4
Grid connect mode 6-4
operating in 6-36
operators notes 6-4
Trip to Hot Standby 6-38
Power generation to hot standby
description, see transition from load reduction 5-33
Power level
changing in Power Generation 6-37
Power outage
fuel cell shutdown explained 5-6
what happens 5-2
Power ramp up
end cells, see note 6-12
PPR
See plant protective response
Preconverter
afterfilter removed 5-5, 6-76
control 5-13
judging performance 5-5
purging 6-70, 6-72
temperature control 5-4
Pre-startup
instrument air valve lineup 6-96
nitrogen valve lineup 6-80
valve lineup digester gas 6-98
valve lineup for fuel cell 6-104
water treatment valve lineup 6-86
Primary air flow, see air flow control 5-14
Process and utilities
enabling startup 5-30
Process halts
Heatup ramp hold 4-2
Hot Standby step down 4-3
Producing power
locking out electrical after 6-90
Product water tank
See deionized water storage tank 5-23
Pro-plus computer
logging on 1-15
shutting down DeltaV 1-16
PSG
See peak shave gas
Purge nitrogen
control 5-20
Purging
AGO skid 6-83
desulfurizer 6-70
desulfurizer A 6-70
desulfurizer B 6-71
desulfurizers 6-64

preconverter 6-70, 6-72

R

Ramp down
reduced kW 4-2
Ramp limits
built into programing 5-19
Rapid purge
disconnecting six-pack 6-79
six-pack changing 6-79
starting 6-78
Rapid Restart
description 5-36
initial conditions 6-48
potential problems 6-48
procedure 6-48
when ends, see Note step 19 6-50
with anode cover gas 6-49
without anode cover gas 6-51
Raw digester gas
See digester gas
Recycle
water treatment 5-8
Reduced kW ramp down 4-2
Reforming hydrocarbons reaction
preconverter 5-13
Replacing
desulfurizer carbon media 6-74
Required screen prints table 6-45
Reset
fail message trip 4-5
first-out trip 4-5
shutdown 4-5
trip trap 4-5
trips 4-5
Responsibilities
emergency shutdown 2-2, 3-2
FCE operator 1-12
King County 2-2, 3-2
operator, on shutdown 5-2
Reverse osmosis
control 5-22
pre-filters 5-22
RO
See reverse osmosis

S

Safety
confined spaces 2-3, 3-3
electrical classification 2-2
general 2-3, 3-3
hot work 2-3, 3-3
UPS battery 2-3
Safety features 2-2, 3-2
Sampling
sulfur 6-76
Screen prints table
required 6-45
Secondary air flow, see air flow control 5-14
Securing
electrical system after producing power 6-90
Shift reaction
preconverter 5-13
Shutdown 4-4
cold starting after 6-14
DCS on UPS 4-4
due to computer failure 4-4
hardwired button 5-34
manual 4-5
manual locations 4-5
no power available 4-4
power available 4-4
reset 4-5
reset trips 4-5
screen with first-out marked 5-35
shutdown screen 5-35
valve table 5-35
SHUTDOWN to IDLE
changing 6-15
Shutting down
startup skid 6-60
Six-pack
changing rapid purge 6-79
changing slow purge 6-79
disconnecting rapid purge 6-79
disconnecting slow purge 6-79
Slow purge
changing six-pack 6-79
disconnecting six-pack 6-79
starting 6-78
Stack
See fuel cell stack
Stack fuel gas flow, see also fuel cell stack 5-16
Start up to Hot Standby plant setting DG 6-32
Starting up
from ambient temperature 6-14
startup skid 6-60
Startup blower
control 5-10
description 5-10
Startup heater

control 5-10
description 5-10
high limit alarm 5-10
Startup skid
control 5-10
design specifications 5-10
high limit alarm 5-10
local alarms 4-18
maximum heatup 300°F, see heatup 1 6-2
overview 1-6
power 5-10
shutting down 6-60
starting up 6-60
Startup to Hot Standby
plant settings table 6-22
plant settings table Hot Restart 6-47
Steam-to-carbon ratio
water flow must start 6-3
water injection rate 5-12
SulfaTreat
bed life 5-9
LEL and toxic gas detectors 5-27
specifications 5-27
vessel control 5-8
Sulfur
sampling 6-76

T

Temperature controller TC-238 5-15
Tertiary air flow
controller 5-14
see air flow control 5-14
Transfer pumps
deionized water 5-24
Transition checklist
blue text, see step 9 6-18
using 1-14
Trip recovery
operators notes 6-6
plant settings table 6-45
procedure 6-42
required screen prints table 6-45
Trip to Hot Standby
Power Generation 6-38
Trip trap
reset 4-5

U

Uninteruptible power supply
see UPS
UPS
before starting 6-91
replacing the batteries 6-92
shutting down 6-92
starting 6-92
testing 6-92
testing 120V loads 6-92

V

Ventilation
operating 6-94
Voltage
fuel cell stack 5-16
Voltage deviation
cell group monitoring 6-12
end cells, see note under halting power ramp up 6-12
halting power ramp up 6-12
monitoring 6-12
using a trend 6-12

W

Water and gas flow
valve settings 6-3
Water softeners 5-22
Water storage tank
deionized 5-23
Water system
enclosure 5-22
Water tank
control strategy 5-24
Water treatment
alarms 5-25
before starting 6-84
control 5-8
Control panel, illustration 5-25
design specifications 1-10
distribution system, shutting down 6-85
local control panel, illustration 5-25
normal operation 6-85
pre-startup valve lineup 6-86
recycle 5-8
restarting after a power loss 6-85
schematic 5-23
screen, illustration 5-25
shed 1-9
shutting down 6-85
starting 6-84
Welding receptacle
startup skid power 5-10

SECTION A
Appendix

A.1 KCPP DFC1500-1 Plant pre-startup valve lineup A-2
A.2 KCPP DFC1500-1 ADG system startup, polisher A to B pre-startup valve lineup A-8
A.3 KCPP DFC1500-1 Instrument air system pre-startup valve lineup A-14
A.4 KCPP DFC1500-1 Water treatment system pre-startup valve lineup A-18
A.5 KCPP DFC1500-1 Nitrogen system pre-startup valve lineup A-20

A.1 KCPP DFC1500-1 Plant pre-startup valve lineup

Valve Lineup Started (Date/Time): _____

VALVE	DESCRIPTION	POSITION	NOTES	INITIALS
Proprietary information— Not Available for Publication.				

VALVE	DESCRIPTION	POSITION	NOTES	INITIALS

VALVE	DESCRIPTION	POSITION	NOTES	INITIALS

VALVE	DESCRIPTION	POSITION	NOTES	INITIALS

VALVE	DESCRIPTION	POSITION	NOTES	INITIALS

Valve Lineup Completed (Date/Time): _____

A.2 KCPP DFC1500-1 ADG system startup, polisher A to B pre-startup valve lineup

Valve Lineup Started (Date/Time): _____

VALVE	DESCRIPTION	POSITION	NOTES	INITIALS
Proprietary information— Not Available for Publication.				

VALVE	DESCRIPTION	POSITION	NOTES	INITIALS

VALVE	DESCRIPTION	POSITION	NOTES	INITIALS

VALVE	DESCRIPTION	POSITION	NOTES	INITIALS

VALVE	DESCRIPTION	POSITION	NOTES	INITIALS

Valve Lineup Completed (Date/Time): _____

A.3 KCPP DFC1500-1 Instrument air system pre-startup valve lineup

Valve Lineup Started (Date/Time): _____

Valve	Description	Position	Notes	Initials
Proprietary information— Not Available for Publication.				

Valve	Description	Position	Notes	Initials

Valve	Description	Position	Notes	Initials

Valve Lineup Completed (Date/Time): _____

A.4 KCPP DFC1500-1 Water treatment system pre-startup valve lineup

Valve Lineup Started (Date/Time): _____

VALVE	DESCRIPTION	POSITION	NOTES	INITIALS
Proprietary information— Not Available for Publication.				

VALVE	DESCRIPTION	POSITION	NOTES	INITIALS

Valve Lineup Completed (Date/Time): _____

A.5 KCPP DFC1500-1 Nitrogen system pre-startup valve lineup

Valve Lineup Started (Date/Time): _____

VALVE	DESCRIPTION	POSITION	NOTES	INITIALS
Proprietary information— Not Available for Publication.				

Valve Lineup Completed (Date/Time): _____

SECTION B
Acronyms and Glossary

B.1 Acronyms and Glossary

Acronyms

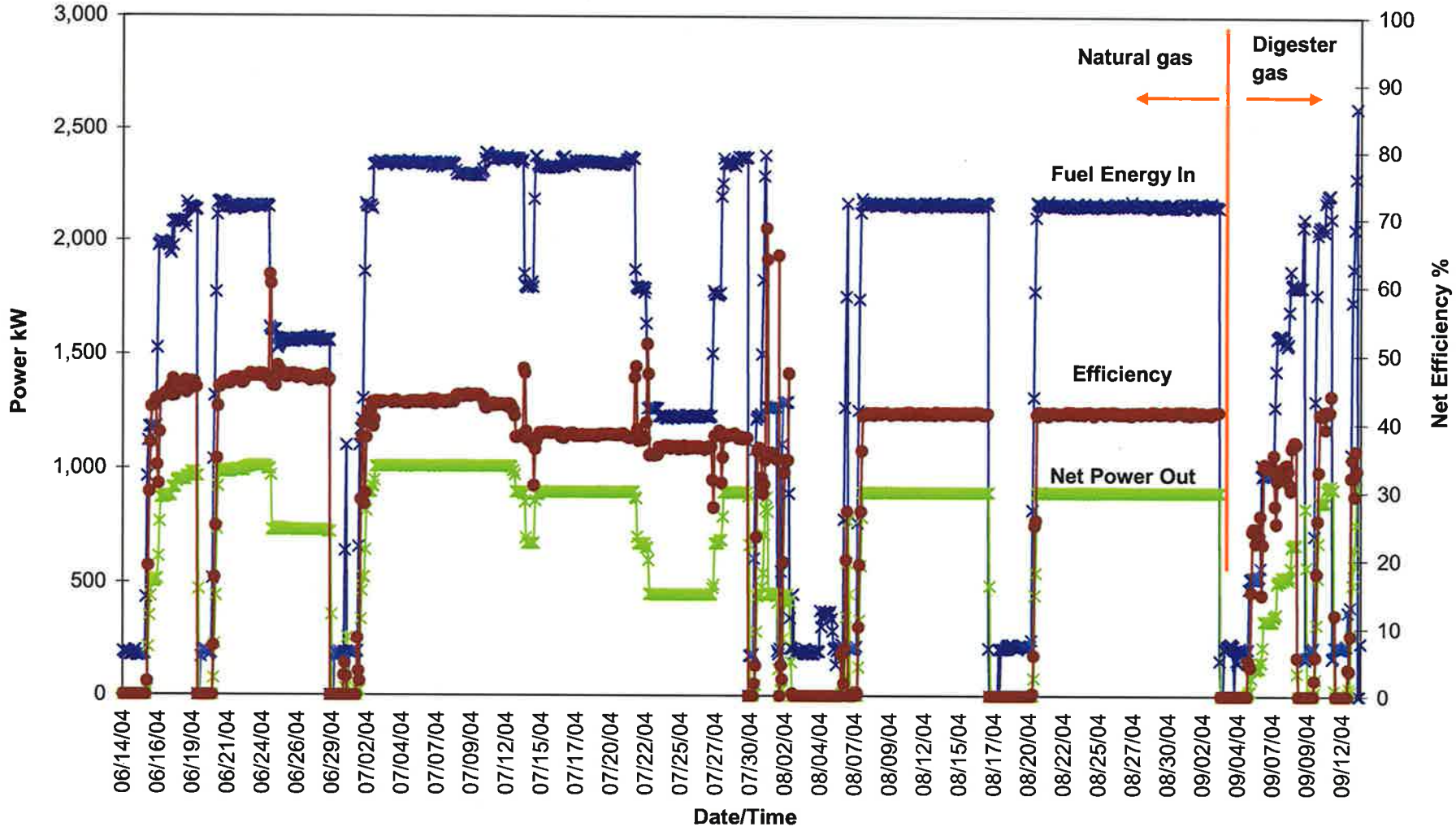
ACG	anode cover gas
ADG	anaerobic digester gas
AGO	anode gas oxidizer
BMS	burner management system
C3LP	strained effluent water low pressure
CDI	continuous deionization
CH4	methane
DCS	distributed control system
DG	digester gas
DI	deionization
dV	voltage deviation
EBOP	electrical balance of plant
ESD	emergency shutdown
FCE	FuelCell Energy, Inc.
H2S	hydrogen sulfide
IA	instrument air
KO	knock out (drum)
LAP	local alarm panel
LEL	lower explosive limit
LSG	low pressure sludge gas
MCFC	molten carbonate fuel cell
N2	nitrogen
NGD	natural gas desulfurized
OIU	operator interface unit
PCS	power conversion system
PPR	plant protective response
PSG	peak shave gas
RO	reverse osmosis
UPS	uninterruptible power supply

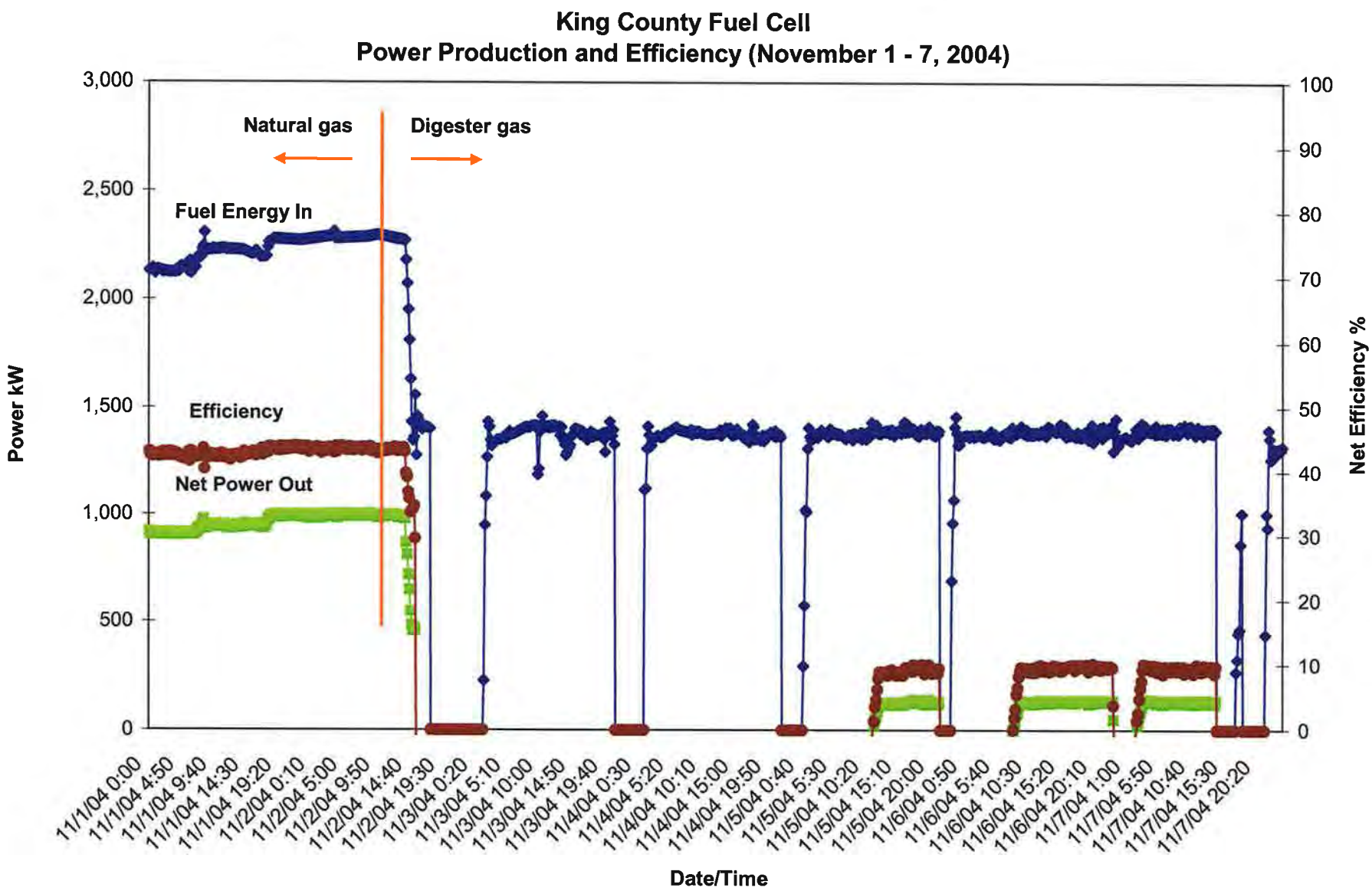
Glossary of terms

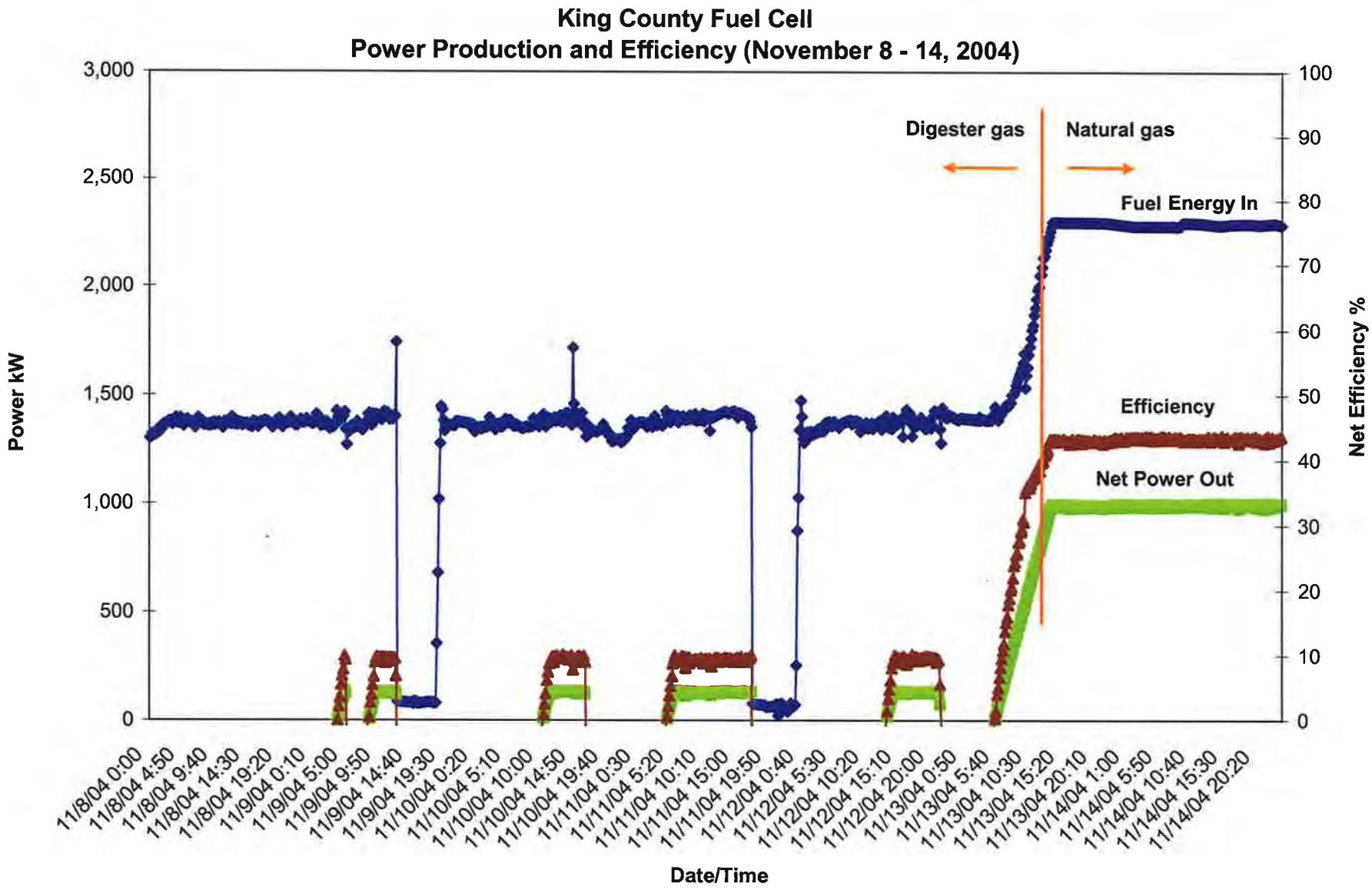
AGO	anode gas oxidizer, the portion of the burner system that uses a catalyst to remove any excess H2 or CH4 in the anode exhaust stream before the gas is recycled to the cathode inlet
App-Station	(Application Station) one of the two operator stations
bleed	also slow bleed, one of the nitrogen purging systems
block valves	isolation valves
DeltaV	the Fuel Cell plant distributed control system
EBOP	the electrical balance of plant enclosure
Forney	the South Plant distributed control system
headworks	the point where the flow enters the treatment plant
KO drum	a vessel filled with reactant used to remove impurities from the gas
Pro-plus	one of two operator stations
stack	the fuel cell stack module or vessel

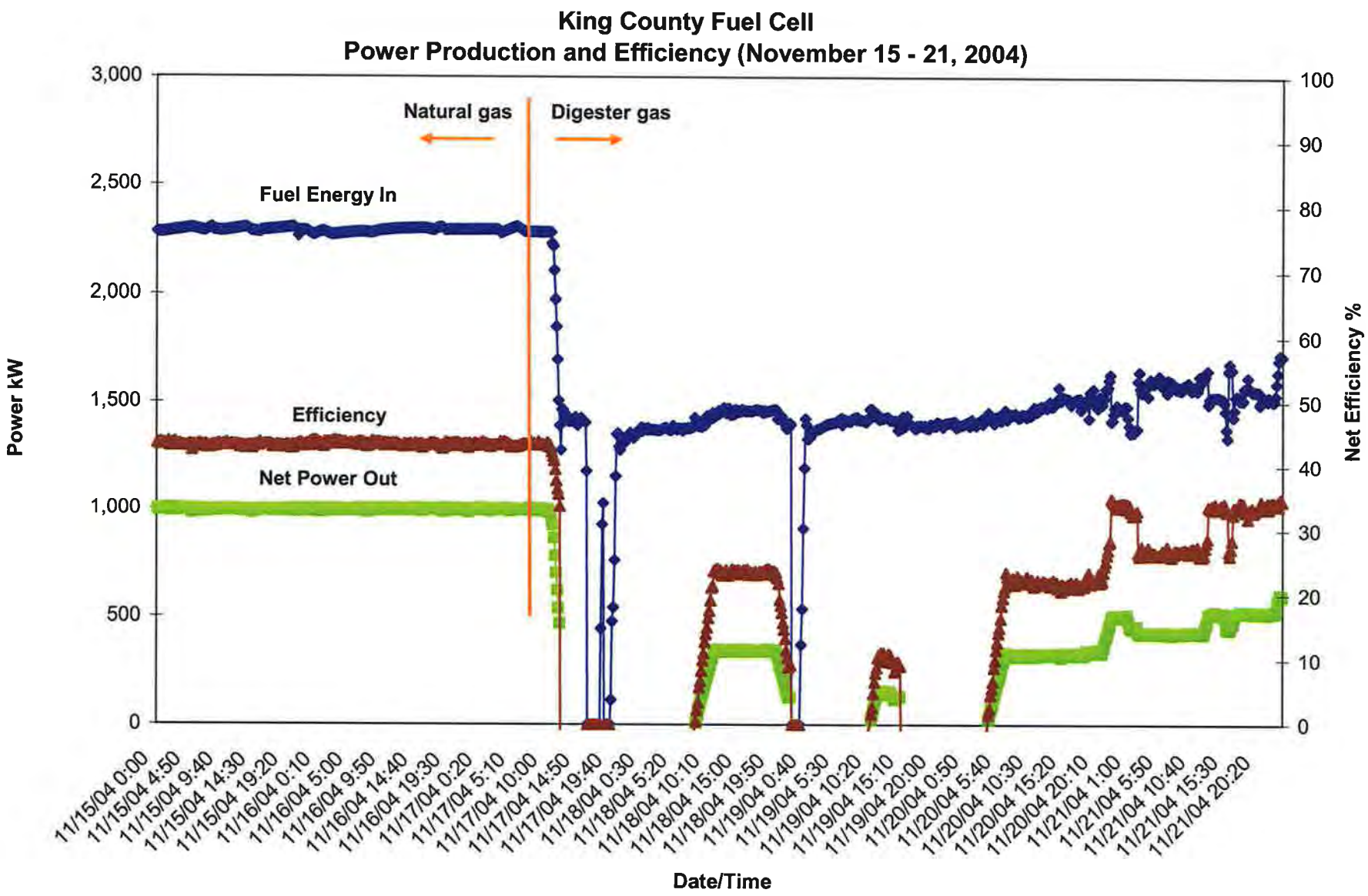
Appendix E
Power Plant Demonstration Period Data Reporting

King County Fuel Cell
Power Production and Efficiency (Third Quarter 2004)




King County Fuel Cell
Power Production and Efficiency (November 1 - 7, 2004)
Natural gas
Digester gas
Fuel Energy In
Efficiency
Net Power Out
Power kW
Net Efficiency %
Date/Time
3,000
2,500
2,000
1,500
1,000
500
0
100
90
80
70
60
50
40
30
20
10
0
11/1/04 0:00
11/1/04 4:50
11/1/04 9:40
11/1/04 14:30
11/1/04 19:20
11/2/04 0:10
11/2/04 5:00
11/2/04 9:50
11/2/04 14:40
11/2/04 19:30
11/3/04 0:20
11/3/04 5:10
11/3/04 10:00
11/3/04 14:50
11/3/04 19:40
11/4/04 0:30
11/4/04 5:20
11/4/04 10:10
11/4/04 15:00
11/4/04 19:50
11/5/04 0:40
11/5/04 5:30
11/5/04 10:20
11/5/04 15:10
11/5/04 20:00
11/6/04 0:50
11/6/04 5:40
11/6/04 10:30
11/6/04 15:20
11/6/04 20:10
11/7/04 1:00
11/7/04 5:50
11/7/04 10:40
11/7/04 15:30
11/7/04 20:20


King County Fuel Cell
Power Production and Efficiency (November 8 - 14, 2004)
Digester gas
Natural gas
Fuel Energy In
Efficiency
Net Power Out
Power kW
Net Efficiency %
Date/Time
3,000
2,500
2,000
1,500
1,000
500
0
100
90
80
70
60
50
40
30
20
10
0
11/8/04 0:00
11/8/04 4:50
11/8/04 9:40
11/8/04 14:30
11/8/04 19:20
11/9/04 0:10
11/9/04 5:00
11/9/04 9:50
11/9/04 14:40
11/9/04 19:30
11/10/04 0:20
11/10/04 5:10
11/10/04 10:00
11/10/04 14:50
11/10/04 19:40
11/11/04 0:30
11/11/04 5:20
11/11/04 10:10
11/11/04 15:00
11/11/04 19:50
11/12/04 0:40
11/12/04 5:30
11/12/04 10:20
11/12/04 15:10
11/12/04 20:00
11/13/04 0:50
11/13/04 5:40
11/13/04 10:30
11/13/04 15:20
11/13/04 20:10
11/14/04 1:00
11/14/04 5:50
11/14/04 10:40
11/14/04 15:30
11/14/04 20:20


King County Fuel Cell
Power Production and Efficiency (November 15 - 21, 2004)
Natural gas
Digester gas
Fuel Energy In
Efficiency
Net Power Out
Power kW
Net Efficiency %
Date/Time
3,000
2,500
2,000
1,500
1,000
500
0
100
90
80
70
60
50
40
30
20
10
0
11/15/04 0:00
11/15/04 4:50
11/15/04 9:40
11/15/04 14:30
11/15/04 19:20
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11/16/04 9:50
11/16/04 14:40
11/16/04 19:30
11/17/04 0:20
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11/17/04 10:00
11/17/04 14:50
11/17/04 19:40
11/18/04 0:30
11/18/04 5:20
11/18/04 10:10
11/18/04 15:00
11/18/04 19:50
11/19/04 0:40
11/19/04 5:30
11/19/04 10:20
11/19/04 15:10
11/19/04 20:00
11/20/04 0:50
11/20/04 5:40
11/20/04 10:30
11/20/04 15:20
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11/21/04 1:00
11/21/04 5:50
11/21/04 10:40
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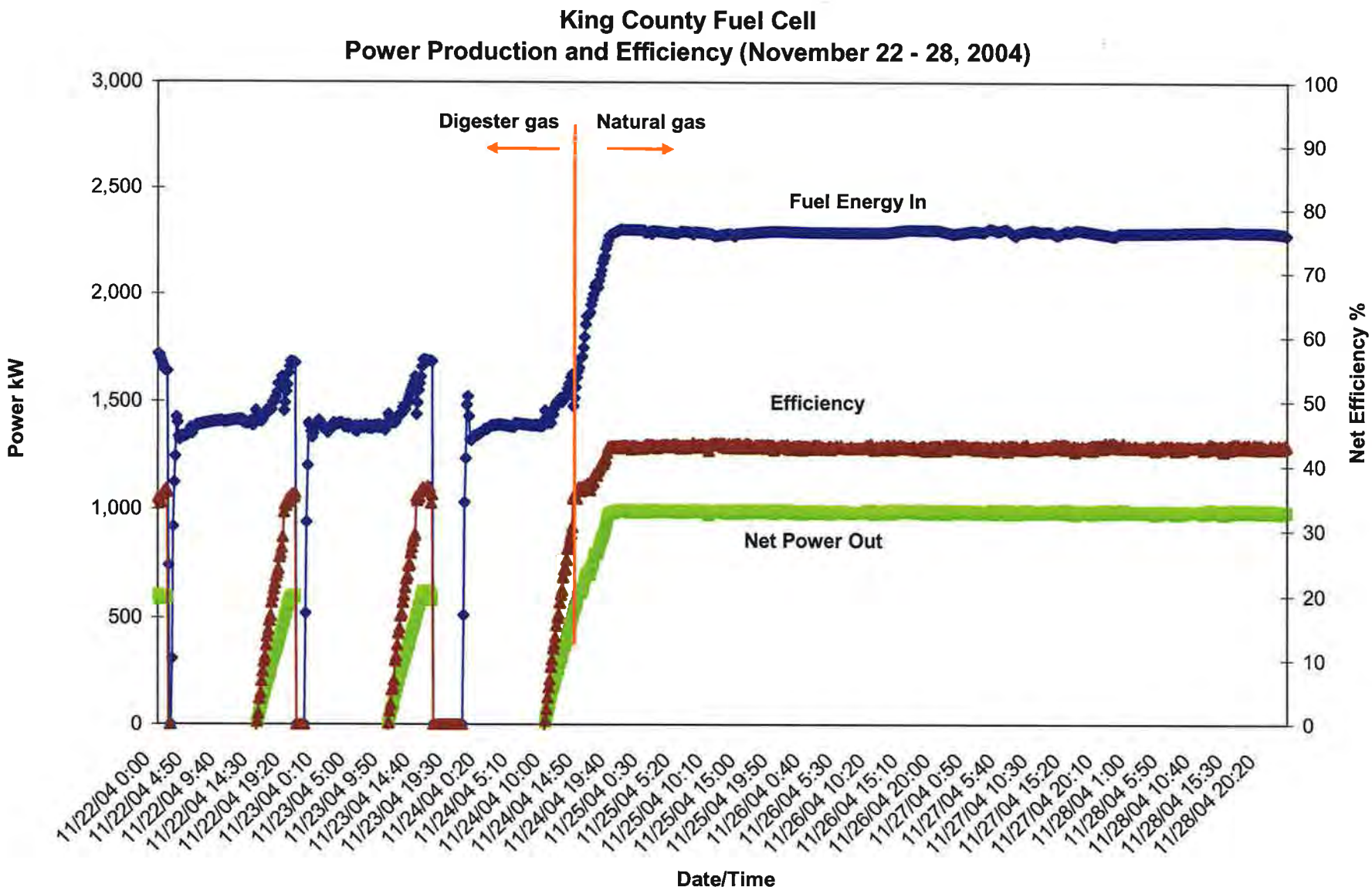
11/21/04 20:20


King County Fuel Cell
Power Production and Efficiency (November 22 - 28, 2004)
Digester gas
Natural gas
Fuel Energy In
Efficiency
Net Power Out
Power kW
Net Efficiency %
Date/Time
3,000
2,500
2,000
1,500
1,000
500
0
100
90
80
70
60
50
40
30
20
10
0
11/22/04 0:00
11/22/04 4:50
11/22/04 9:40
11/22/04 14:30
11/22/04 19:20
11/23/04 0:10
11/23/04 5:00
11/23/04 9:50
11/23/04 14:40
11/23/04 19:30
11/24/04 0:20
11/24/04 5:10
11/24/04 10:00
11/24/04 14:50
11/24/04 19:40
11/25/04 0:30
11/25/04 5:20
11/25/04 10:10
11/25/04 15:00
11/25/04 19:50
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11/26/04 15:10
11/26/04 20:00
11/27/04 0:50
11/27/04 5:40
11/27/04 10:30
11/27/04 15:20
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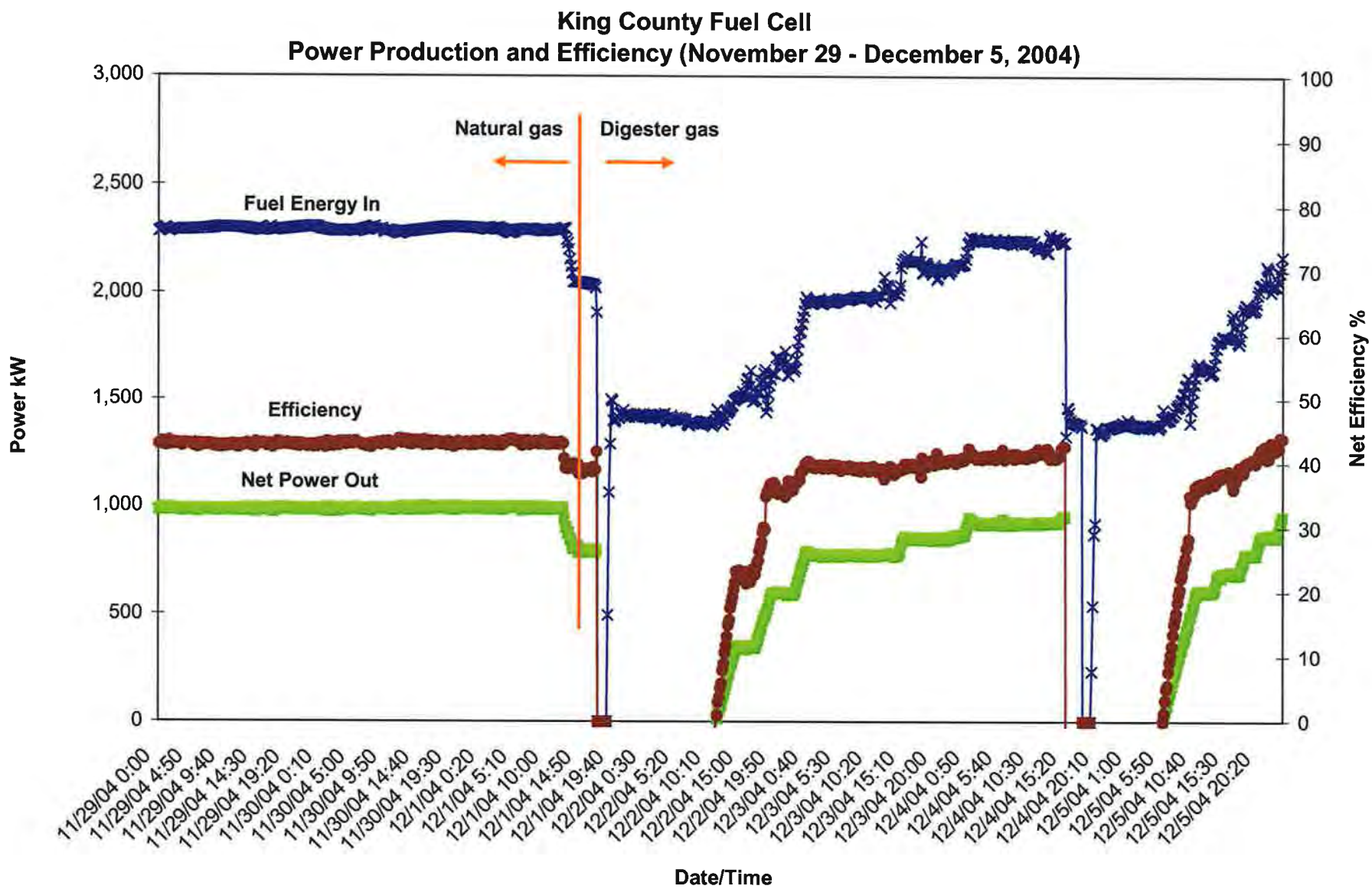
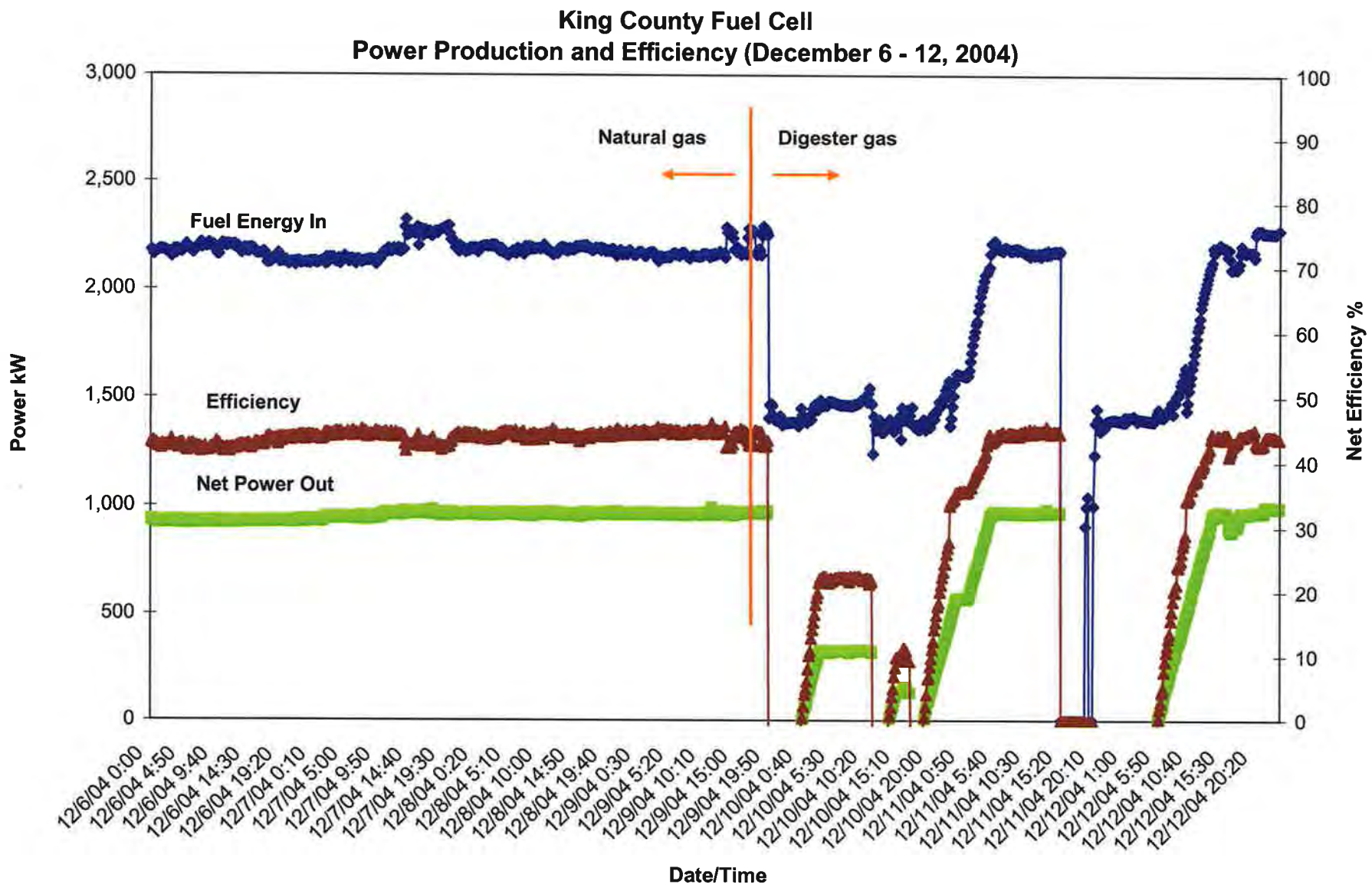
11/28/04 1:00
11/28/04 5:50
11/28/04 10:40
11/28/04 15:30
11/28/04 20:20


King County Fuel Cell
Power Production and Efficiency (November 29 - December 5, 2004)
Natural gas
Digester gas
Fuel Energy In
Efficiency
Net Power Out
Power kW
Net Efficiency %
Date/Time
3,000
2,500
2,000
1,500
1,000
500
0
100
90
80
70
60
50
40
30
20
10
0
11/29/04 0:00
11/29/04 4:50
11/29/04 9:40
11/29/04 14:30
11/29/04 19:20
11/30/04 0:10
11/30/04 5:00
11/30/04 9:50
11/30/04 14:40
11/30/04 19:30
12/1/04 0:20
12/1/04 5:10
12/1/04 10:00
12/1/04 14:50
12/1/04 19:40
12/2/04 0:30
12/2/04 5:20
12/2/04 10:10
12/2/04 15:00
12/2/04 19:50
12/3/04 0:40
12/3/04 5:30
12/3/04 10:20
12/3/04 15:10
12/3/04 20:00
12/4/04 0:50
12/4/04 5:40
12/4/04 10:30
12/4/04 15:20
12/4/04 20:10
12/5/04 1:00
12/5/04 5:50
12/5/04 10:40
12/5/04 15:30
12/5/04 20:20


King County Fuel Cell
Power Production and Efficiency (December 6 - 12, 2004)
Natural gas
Digester gas
Fuel Energy In
Efficiency
Net Power Out
Power kW
Net Efficiency %
Date/Time
3,000
2,500
2,000
1,500
1,000
500
0
100
90
80
70
60
50
40
30
20
10
0
12/6/04 0:00
12/6/04 4:50
12/6/04 9:40
12/6/04 14:30
12/6/04 19:20
12/7/04 0:10
12/7/04 5:00
12/7/04 9:50
12/7/04 14:40
12/7/04 19:30
12/8/04 0:20
12/8/04 5:10
12/8/04 10:00
12/8/04 14:50
12/8/04 19:40
12/9/04 0:30
12/9/04 5:20
12/9/04 10:10
12/9/04 15:00
12/9/04 19:50
12/10/04 0:40
12/10/04 5:30
12/10/04 10:20
12/10/04 15:10
12/10/04 20:00
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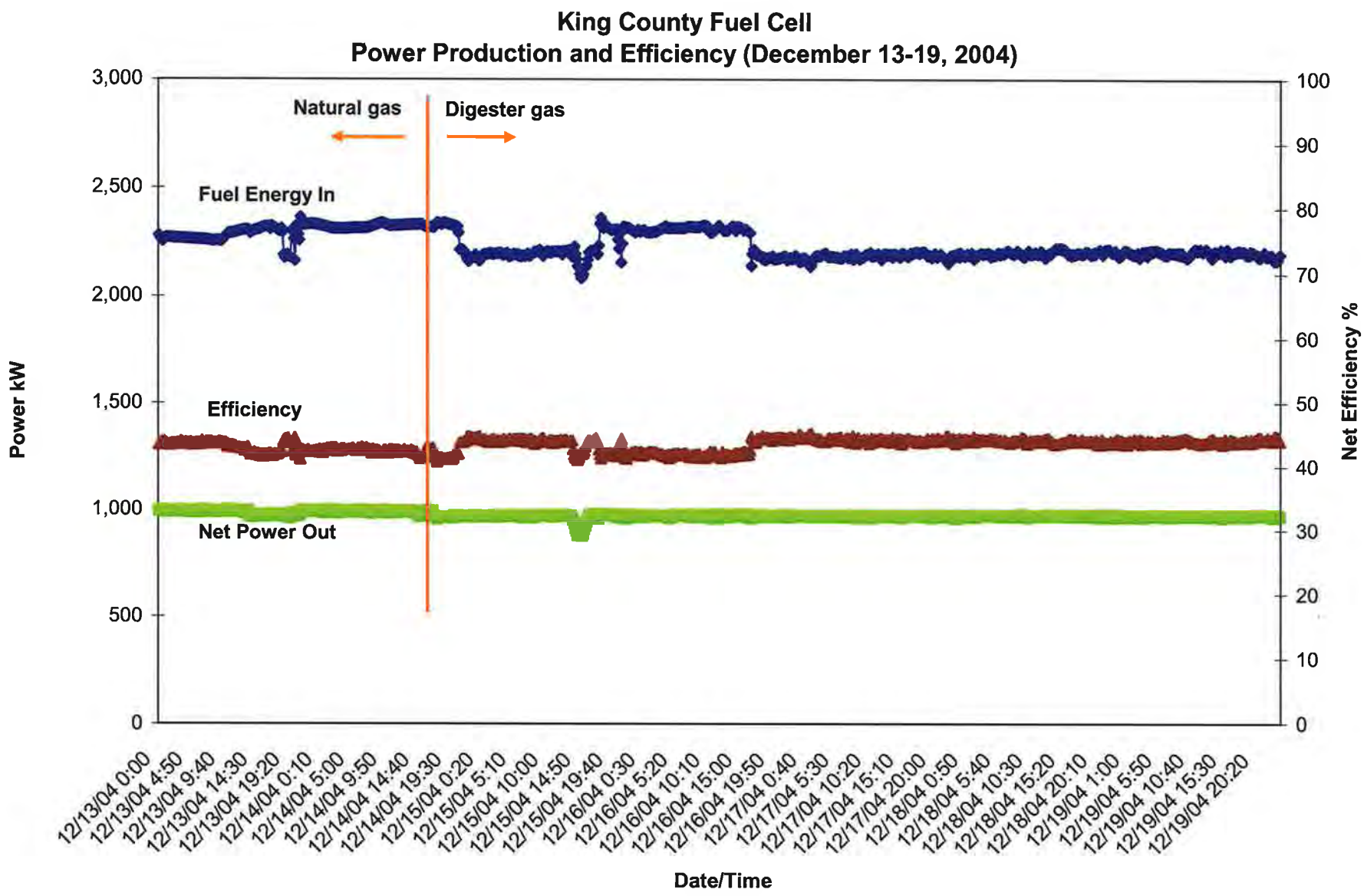
12/11/04 10:30
12/11/04 15:20
12/11/04 20:10
12/12/04 1:00
12/12/04 5:50
12/12/04 10:40
12/12/04 15:30
12/12/04 20:20


King County Fuel Cell
Power Production and Efficiency (December 13-19, 2004)
Natural gas
Digester gas
Fuel Energy In
Efficiency
Net Power Out
Power kW
Net Efficiency %
Date/Time
3,000
2,500
2,000
1,500
1,000
500
0
100
90
80
70
60
50
40
30
20
10
0
12/13/04 0:00
12/13/04 4:50
12/13/04 9:40
12/13/04 14:30
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12/14/04 9:50
12/14/04 14:40
12/14/04 19:30
12/15/04 0:20
12/15/04 5:10
12/15/04 10:00
12/15/04 14:50
12/15/04 19:40
12/16/04 0:30
12/16/04 5:20
12/16/04 10:10
12/16/04 15:00
12/16/04 19:50
12/17/04 0:40
12/17/04 5:30
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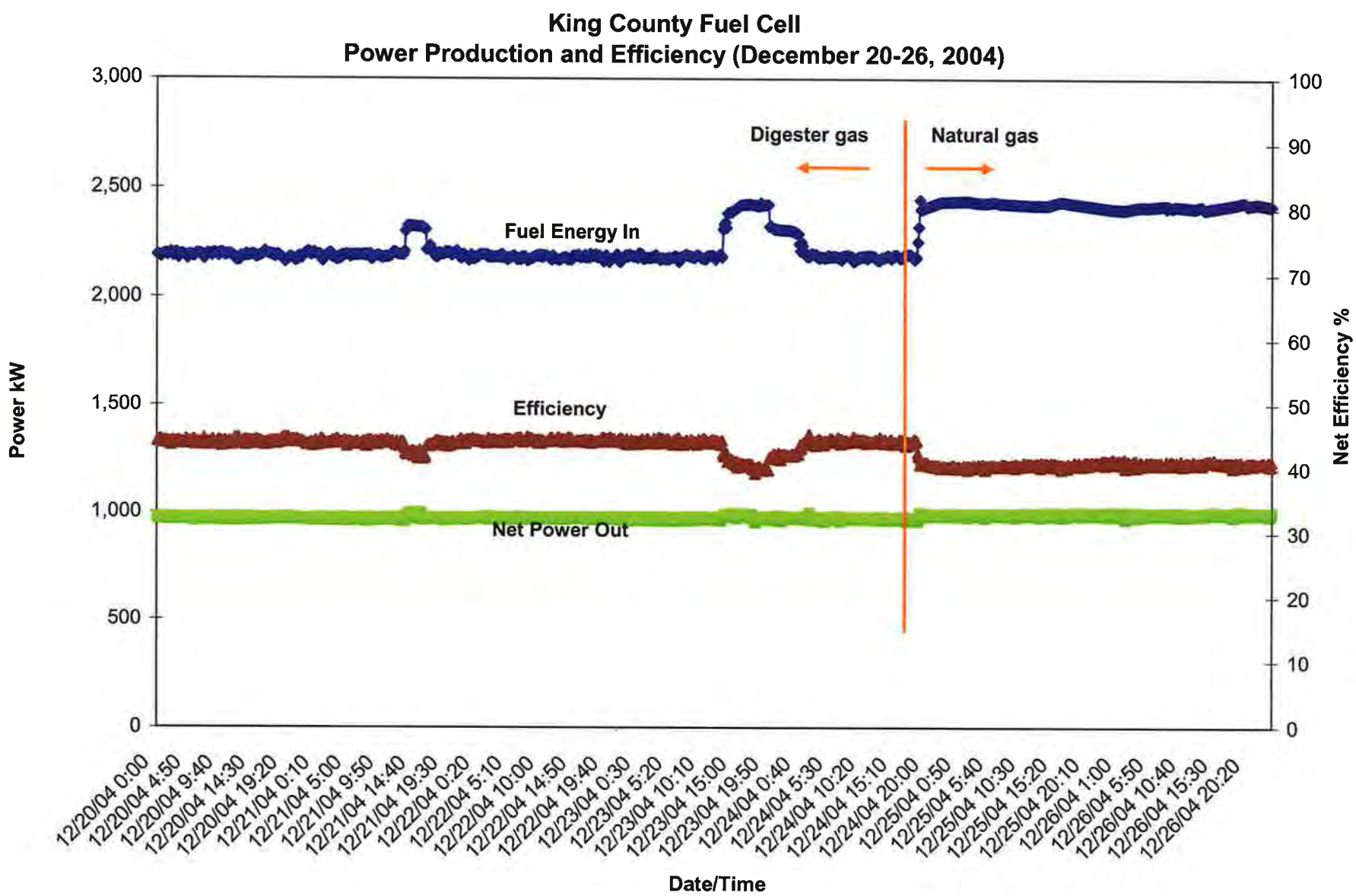
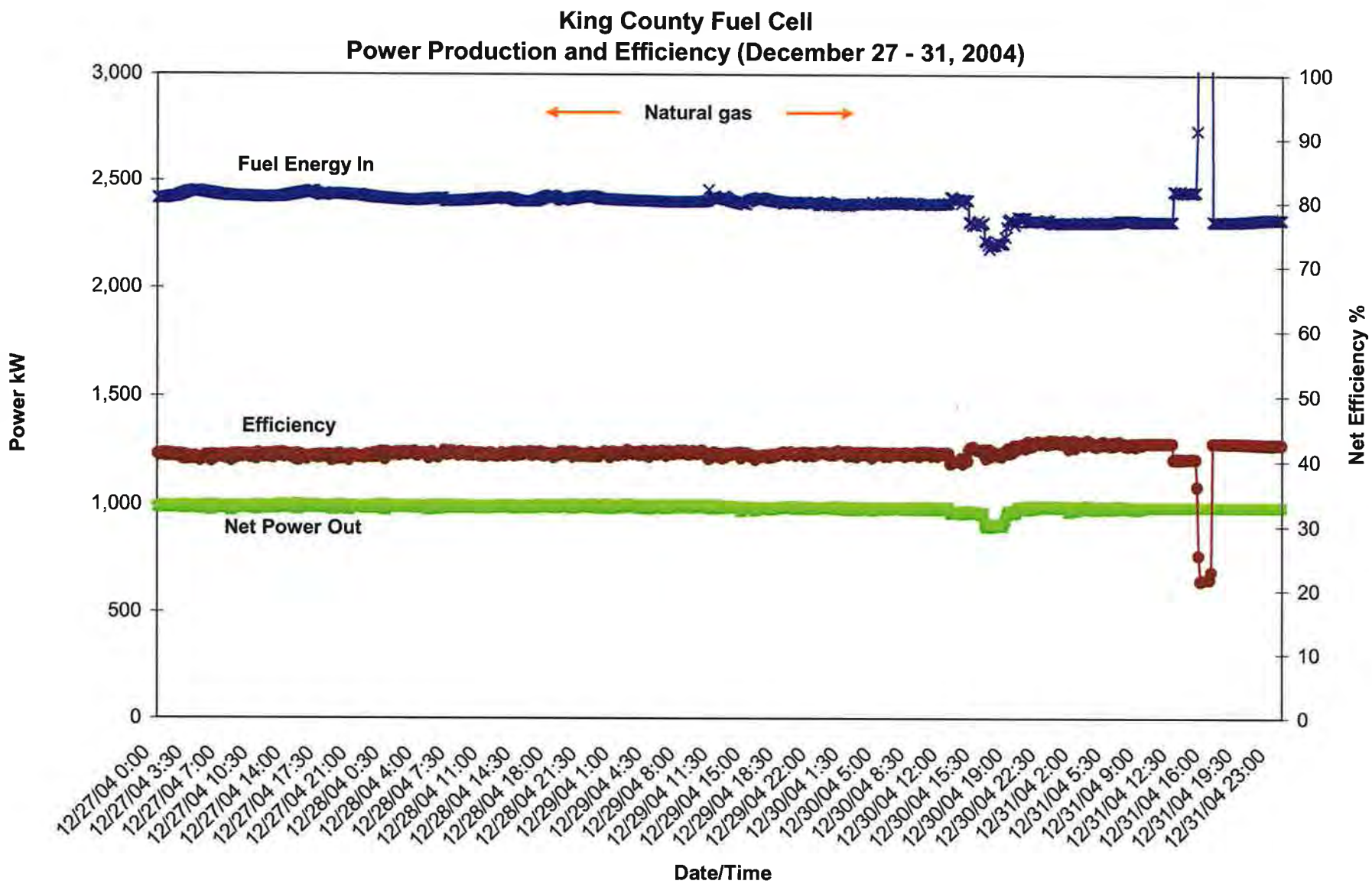
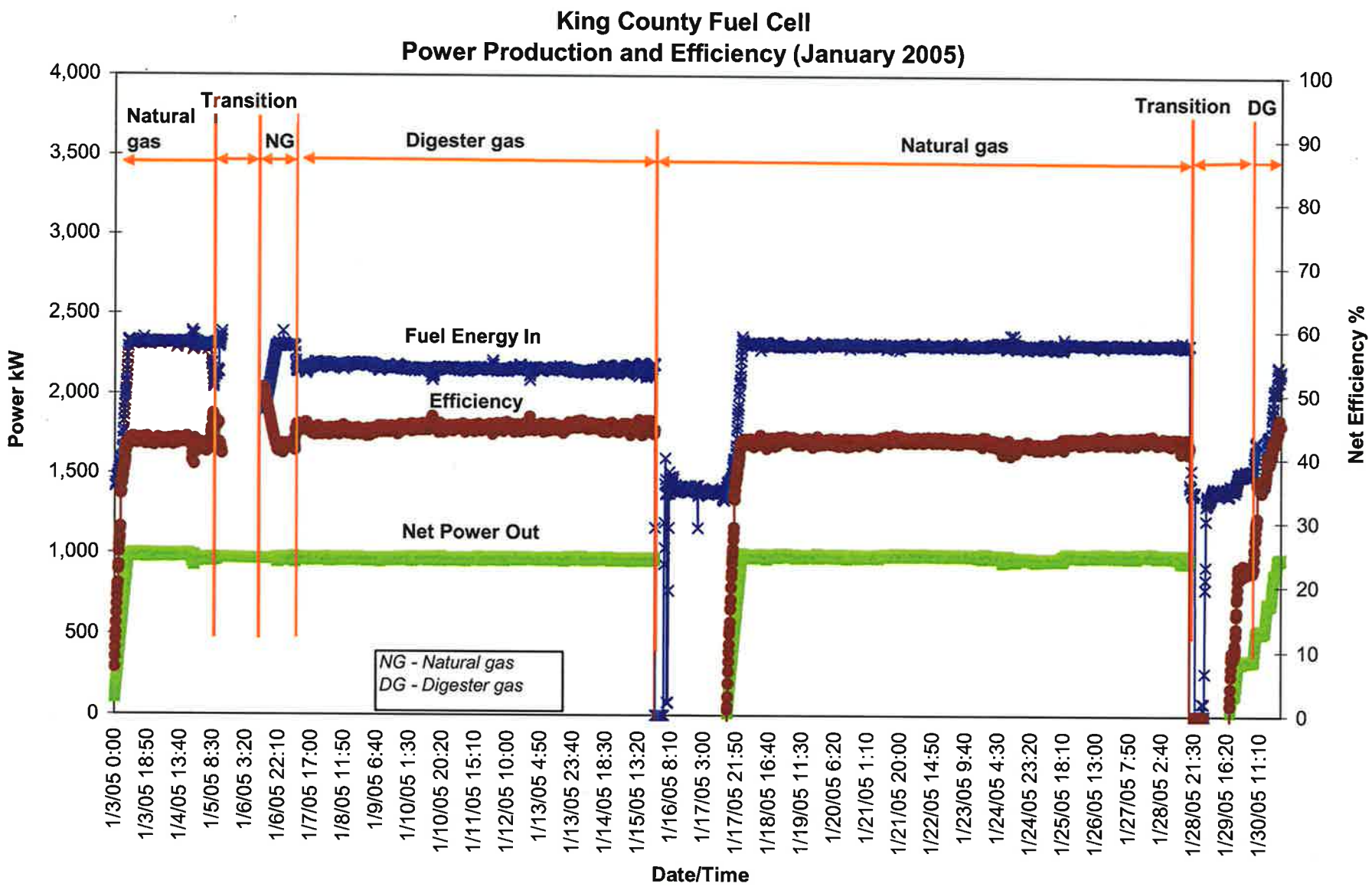
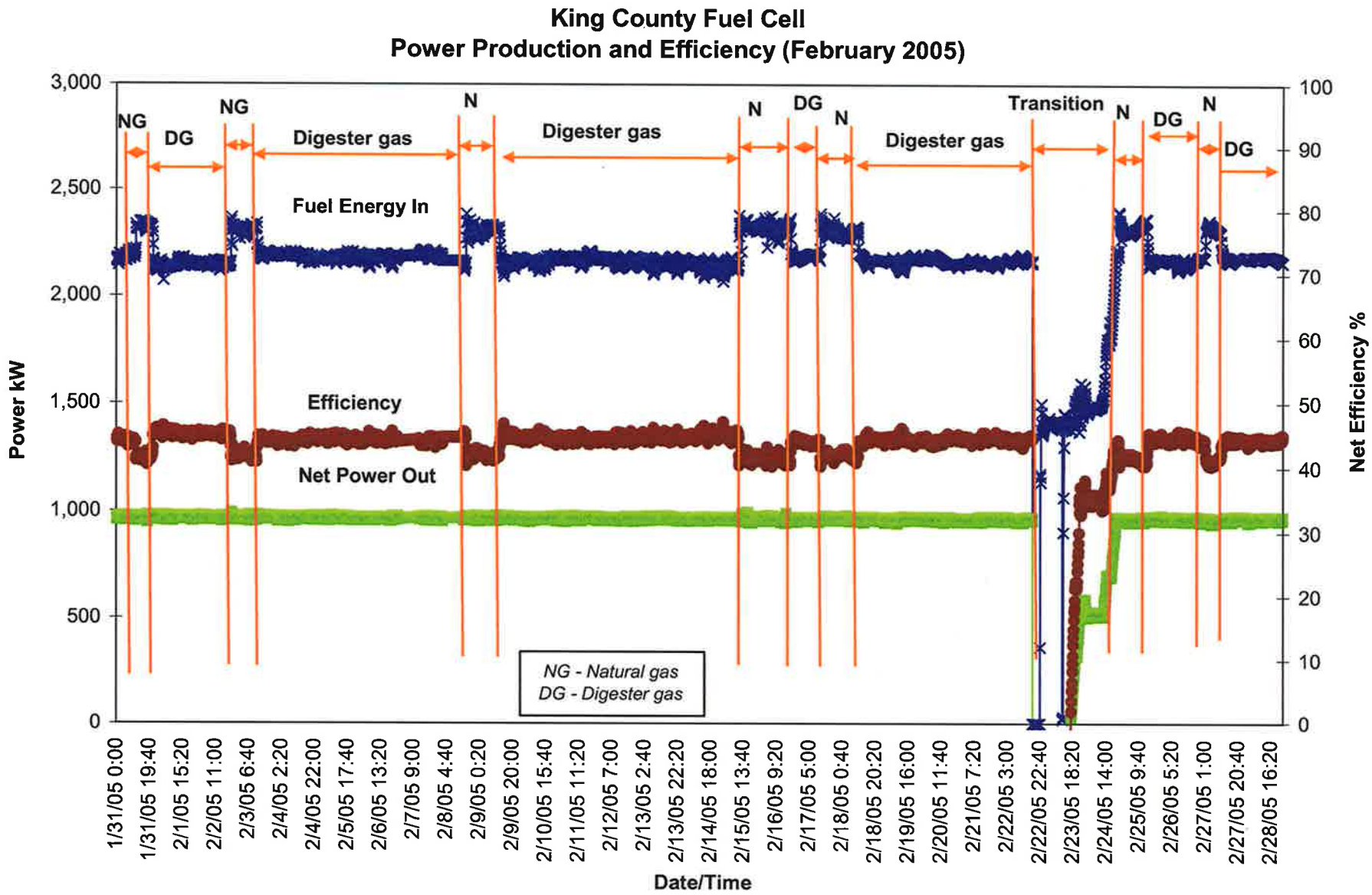
12/17/04 15:10
12/17/04 20:00
12/18/04 0:50
12/18/04 5:40
12/18/04 10:30
12/18/04 15:20
12/18/04 20:10
12/19/04 1:00
12/19/04 5:50
12/19/04 10:40
12/19/04 15:30
12/19/04 20:20


King County Fuel Cell
Power Production and Efficiency (December 20-26, 2004)
Digester gas
Natural gas
Fuel Energy In
Efficiency
Net Power Out
Power kW
Net Efficiency %
Date/Time
3,000
2,500
2,000
1,500
1,000
500
0
100
90
80
70
60
50
40
30
20
10
0
12/20/04 0:00
12/20/04 4:50
12/20/04 9:40
12/20/04 14:30
12/20/04 19:20
12/21/04 0:10
12/21/04 5:00
12/21/04 9:50
12/21/04 14:40
12/21/04 19:30
12/22/04 0:20
12/22/04 5:10
12/22/04 10:00
12/22/04 14:50
12/22/04 19:40
12/23/04 0:30
12/23/04 5:20
12/23/04 10:10
12/23/04 15:00
12/23/04 19:50
12/24/04 0:40
12/24/04 5:30
12/24/04 10:20
12/24/04 15:10
12/24/04 20:00
12/25/04 0:50
12/25/04 5:40
12/25/04 10:30
12/25/04 15:20
12/25/04 20:10
12/26/04 1:00
12/26/04 5:50
12/26/04 10:40
12/26/04 15:30
12/26/04 20:20


King County Fuel Cell
Power Production and Efficiency (December 27 - 31, 2004)
Natural gas
Fuel Energy In
Efficiency
Net Power Out
Power kW
Net Efficiency %
Date/Time
3,000
2,500
2,000
1,500
1,000
500
0
100
90
80
70
60
50
40
30
20
10
0
12/27/04 0:00
12/27/04 3:30
12/27/04 7:00
12/27/04 10:30
12/27/04 14:00
12/27/04 17:30
12/27/04 21:00
12/28/04 0:30
12/28/04 4:00
12/28/04 7:30
12/28/04 11:00
12/28/04 14:30
12/28/04 18:00
12/28/04 21:30
12/29/04 1:00
12/29/04 4:30
12/29/04 8:00
12/29/04 11:30
12/29/04 15:00
12/29/04 18:30
12/29/04 22:00
12/30/04 1:30
12/30/04 5:00
12/30/04 8:30
12/30/04 12:00
12/30/04 15:30
12/30/04 19:00
12/30/04 22:30
12/31/04 2:00
12/31/04 5:30
12/31/04 9:00
12/31/04 12:30
12/31/04 16:00
12/31/04 19:30
12/31/04 23:00


King County Fuel Cell
Power Production and Efficiency (January 2005)
Natural gas
Transition
NG
Digester gas
Natural gas
Transition
DG
Fuel Energy In
Efficiency
Net Power Out
NG - Natural gas
DG - Digester gas
Power kW
Net Efficiency %
Date/Time
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
100
90
80
70
60
50
40
30
20
10
0
1/3/05 0:00
1/3/05 18:50
1/4/05 13:40
1/5/05 8:30
1/6/05 3:20
1/6/05 22:10
1/7/05 17:00
1/8/05 11:50
1/9/05 6:40
1/10/05 1:30
1/10/05 20:20
1/11/05 15:10
1/12/05 10:00
1/13/05 4:50
1/13/05 23:40
1/14/05 18:30
1/15/05 13:20
1/16/05 8:10
1/17/05 3:00
1/17/05 21:50
1/18/05 16:40
1/19/05 11:30
1/20/05 6:20
1/21/05 1:10
1/21/05 20:00
1/22/05 14:50
1/23/05 9:40
1/24/05 4:30
1/24/05 23:20
1/25/05 18:10
1/26/05 13:00
1/27/05 7:50
1/28/05 2:40
1/28/05 21:30
1/29/05 16:20
1/30/05 11:10


King County Fuel Cell
Power Production and Efficiency (February 2005)
Power kW
Net Efficiency %
Date/Time
NG
DG
Digester gas
N
Transition
Fuel Energy In
Efficiency
Net Power Out
NG - Natural gas
DG - Digester gas
3,000
2,500
2,000
1,500
1,000
500
0
100
90
80
70
60
50
40
30
20
10
0
1/31/05 0:00
1/31/05 19:40
2/1/05 15:20
2/2/05 11:00
2/3/05 6:40
2/4/05 2:20
2/4/05 22:00
2/5/05 17:40
2/6/05 13:20
2/7/05 9:00
2/8/05 4:40
2/9/05 0:20
2/9/05 20:00
2/10/05 15:40
2/11/05 11:20
2/12/05 7:00
2/13/05 2:40
2/13/05 22:20
2/14/05 18:00
2/15/05 13:40
2/16/05 9:20
2/17/05 5:00
2/18/05 0:40
2/18/05 20:20
2/19/05 16:00
2/20/05 11:40
2/21/05 7:20
2/22/05 3:00
2/22/05 22:40
2/23/05 18:20
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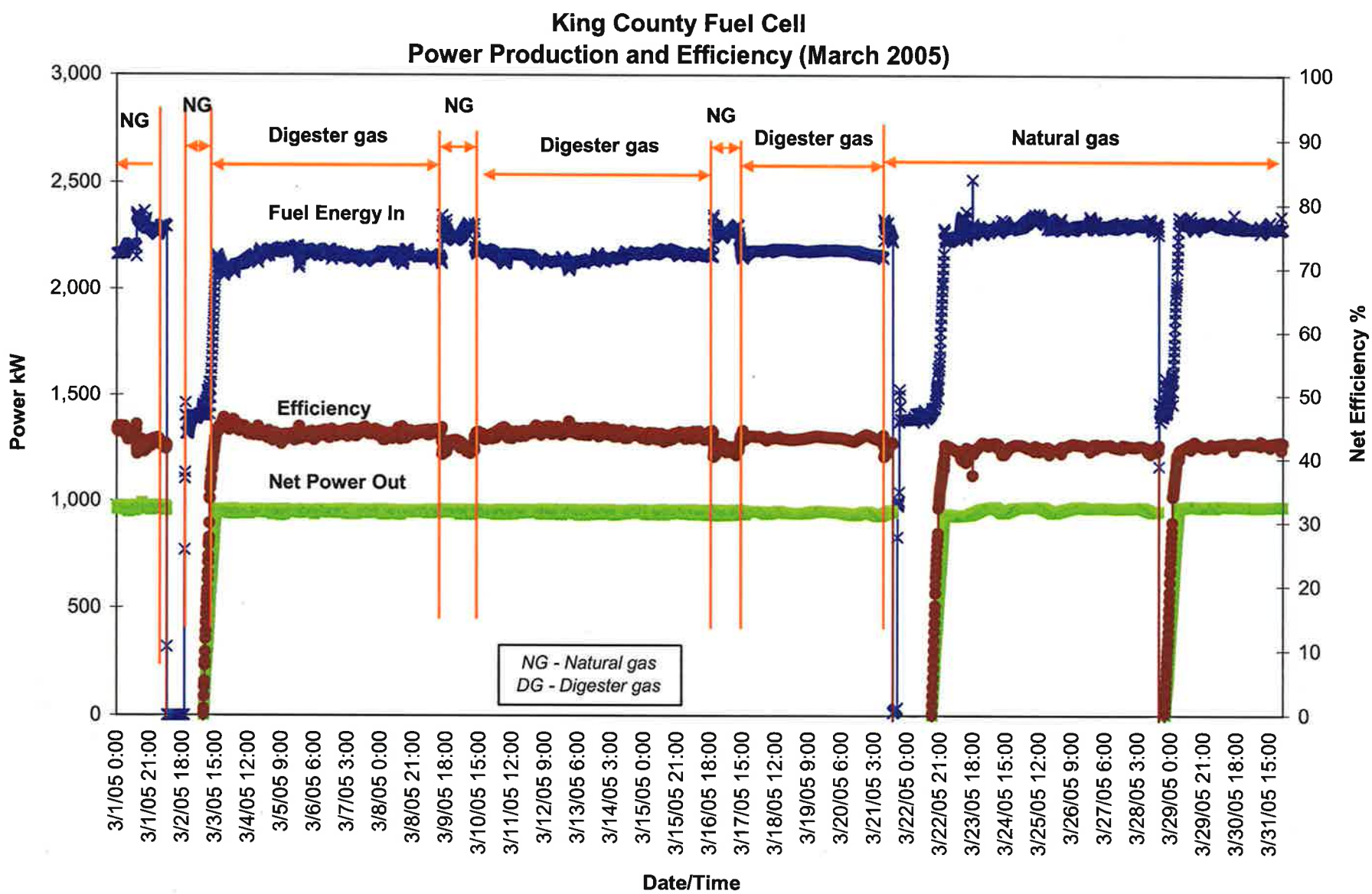
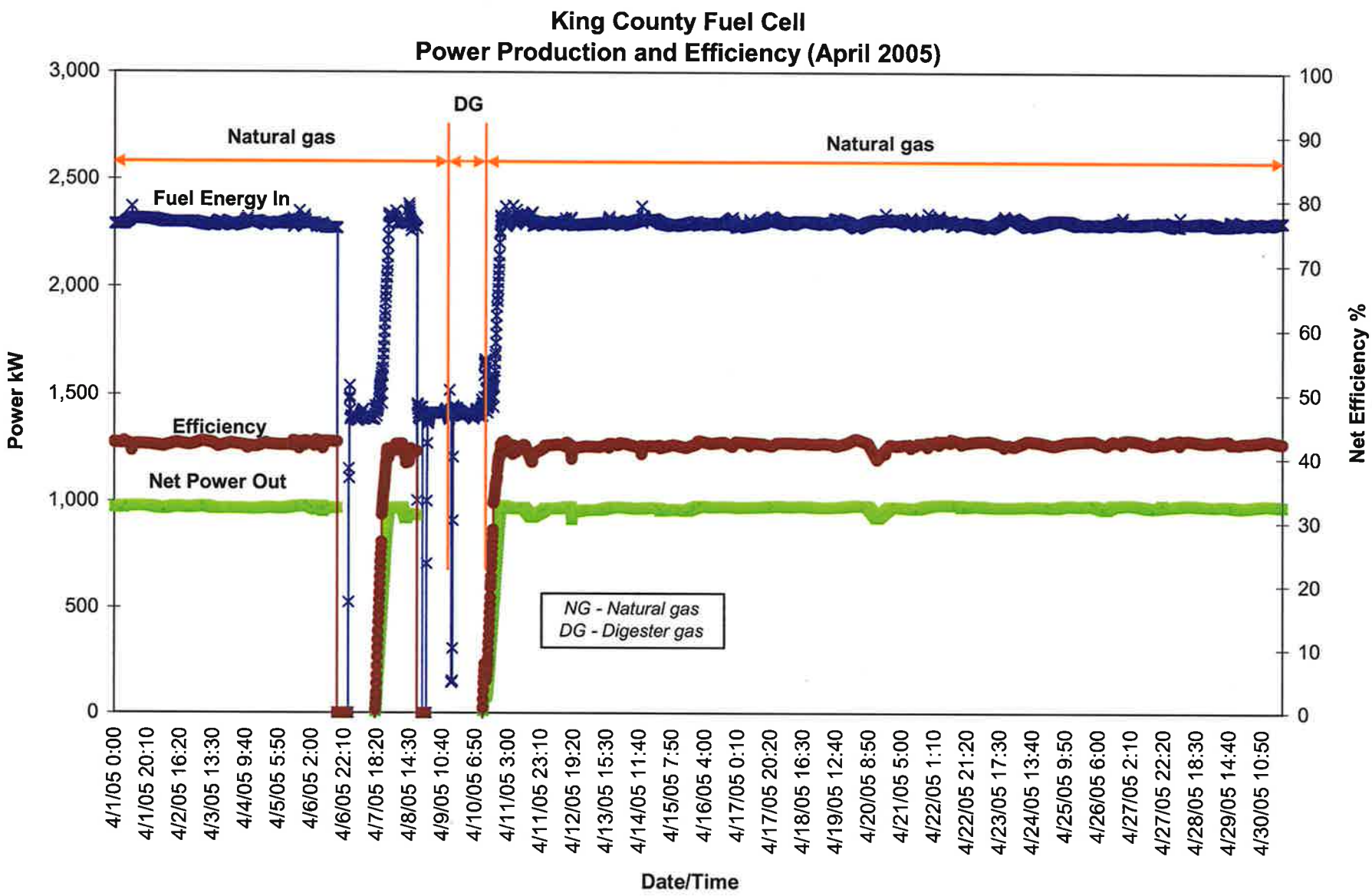
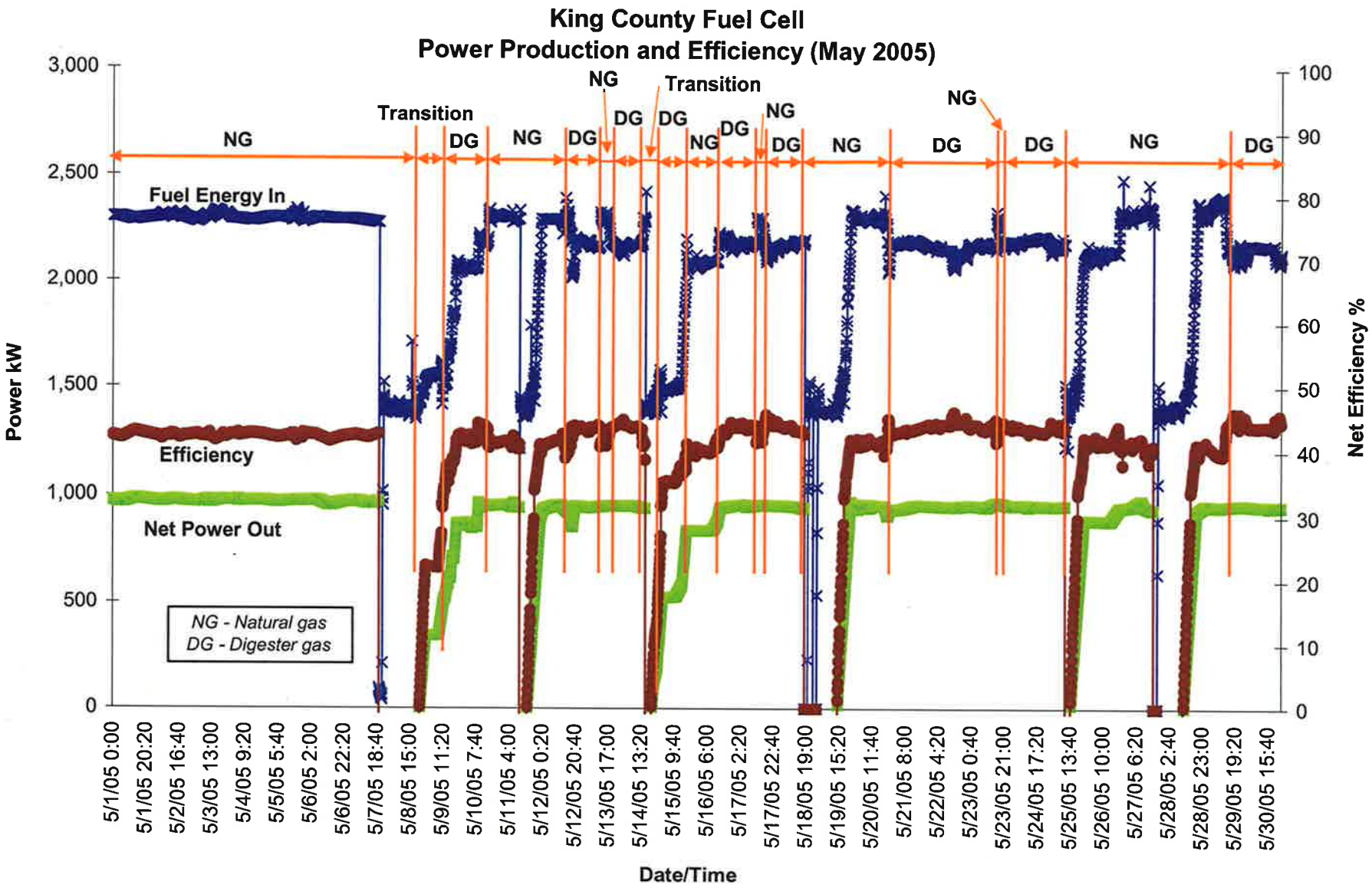
2/27/05 20:40
2/28/05 16:20


King County Fuel Cell
Power Production and Efficiency (March 2005)
NG
NG
Digester gas
NG
Digester gas
NG
Digester gas
Natural gas
Fuel Energy In
Efficiency
Net Power Out
NG - Natural gas
DG - Digester gas
Power kW
Net Efficiency %
Date/Time
3,000
2,500
2,000
1,500
1,000
500
0
100
90
80
70
60
50
40
30
20
10
0
3/1/05 0:00
3/1/05 21:00
3/2/05 18:00
3/3/05 15:00
3/4/05 12:00
3/5/05 9:00
3/6/05 6:00
3/7/05 3:00
3/8/05 0:00
3/8/05 21:00
3/9/05 18:00
3/10/05 15:00
3/11/05 12:00
3/12/05 9:00
3/13/05 6:00
3/14/05 3:00
3/15/05 0:00
3/15/05 21:00
3/16/05 18:00
3/17/05 15:00
3/18/05 12:00
3/19/05 9:00
3/20/05 6:00
3/21/05 3:00
3/22/05 0:00
3/22/05 21:00
3/23/05 18:00
3/24/05 15:00
3/25/05 12:00
3/26/05 9:00
3/27/05 6:00
3/28/05 3:00
3/29/05 0:00
3/29/05 21:00
3/30/05 18:00
3/31/05 15:00


King County Fuel Cell
Power Production and Efficiency (April 2005)
Natural gas
DG
Natural gas
Fuel Energy In
Efficiency
Net Power Out
NG - Natural gas
DG - Digester gas
Power kW
Net Efficiency %
Date/Time
3,000
2,500
2,000
1,500
1,000
500
0
100
90
80
70
60
50
40
30
20
10
0
4/1/05 0:00
4/1/05 20:10
4/2/05 16:20
4/3/05 13:30
4/4/05 9:40
4/5/05 5:50
4/6/05 2:00
4/6/05 22:10
4/7/05 18:20
4/8/05 14:30
4/9/05 10:40
4/10/05 6:50
4/11/05 3:00
4/11/05 23:10
4/12/05 19:20
4/13/05 15:30
4/14/05 11:40
4/15/05 7:50
4/16/05 4:00
4/17/05 0:10
4/17/05 20:20
4/18/05 16:30
4/19/05 12:40
4/20/05 8:50
4/21/05 5:00
4/22/05 1:10
4/22/05 21:20
4/23/05 17:30
4/24/05 13:40
4/25/05 9:50
4/26/05 6:00
4/27/05 2:10
4/27/05 22:20
4/28/05 18:30
4/29/05 14:40
4/30/05 10:50


King County Fuel Cell
Power Production and Efficiency (May 2005)
Power kW
Net Efficiency %
Date/Time
Fuel Energy In
Efficiency
Net Power Out
NG - Natural gas
DG - Digester gas
NG
DG
Transition
3,000
2,500
2,000
1,500
1,000
500
0
100
90
80
70
60
50
40
30
20
10
0
5/1/05 0:00
5/1/05 20:20
5/2/05 16:40
5/3/05 13:00
5/4/05 9:20
5/5/05 5:40
5/6/05 2:00
5/6/05 22:20
5/7/05 18:40
5/8/05 15:00
5/9/05 11:20
5/10/05 7:40
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5/12/05 0:20
5/12/05 20:40
5/13/05 17:00
5/14/05 13:20
5/15/05 9:40
5/16/05 6:00
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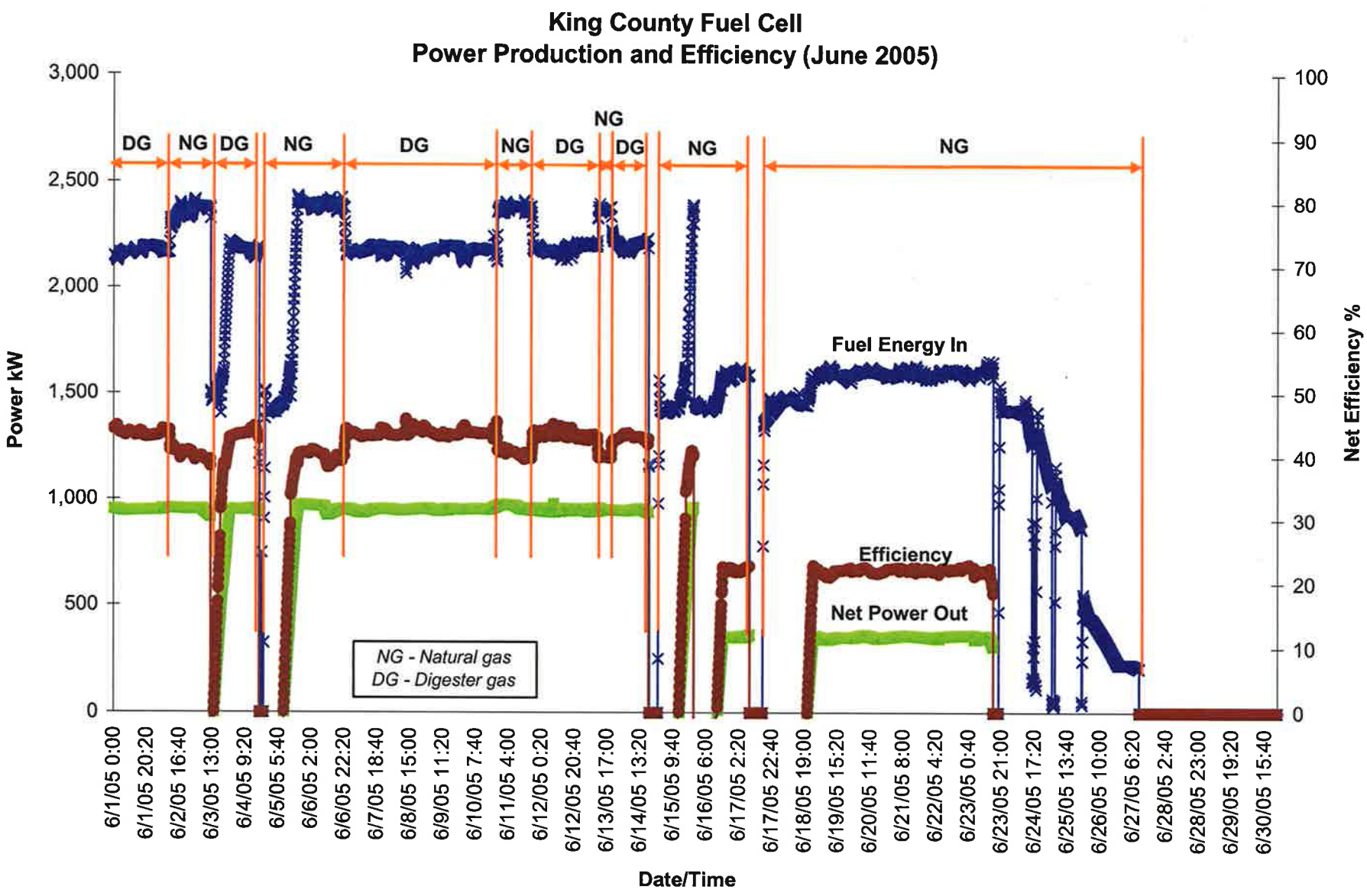
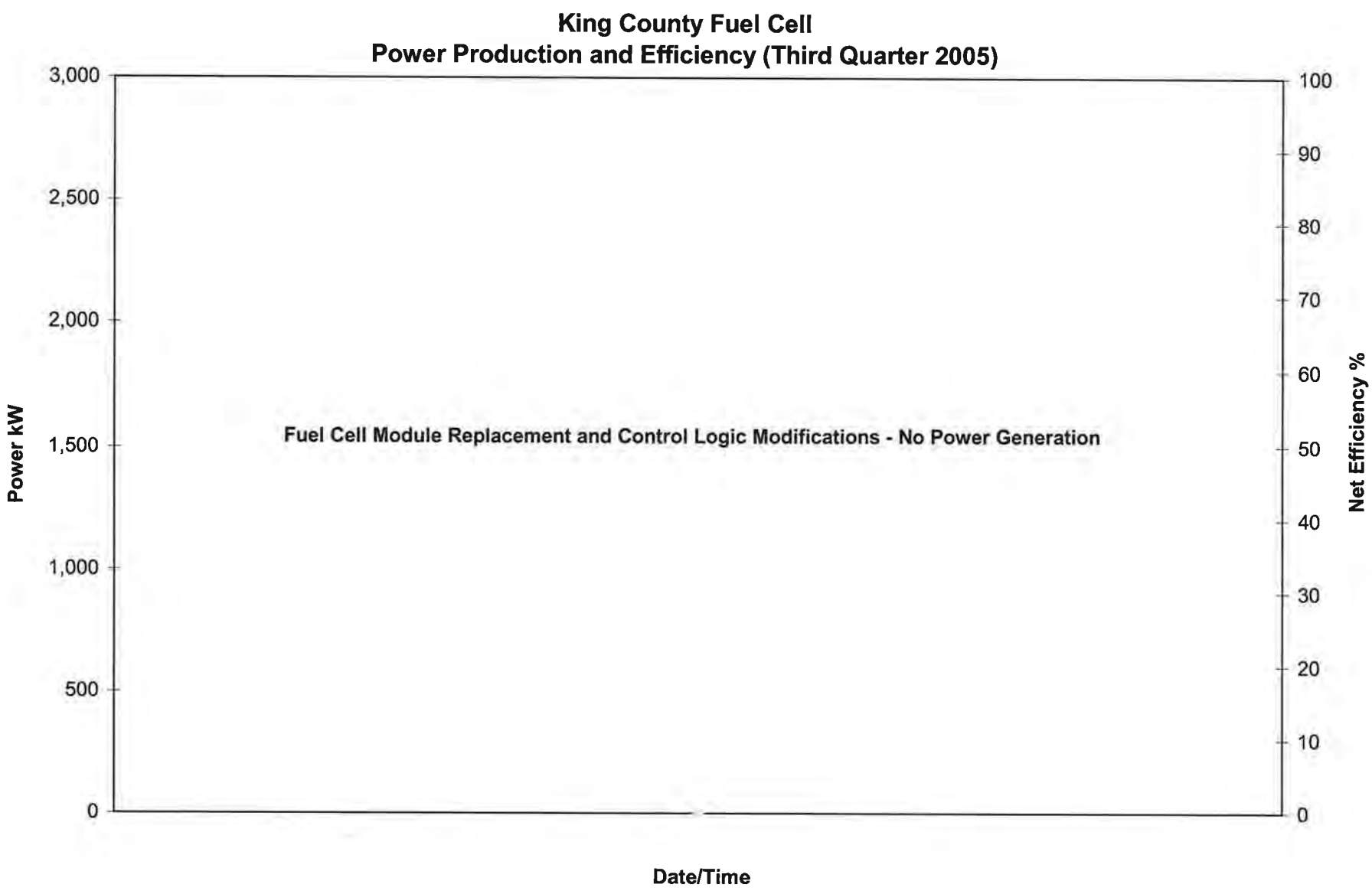
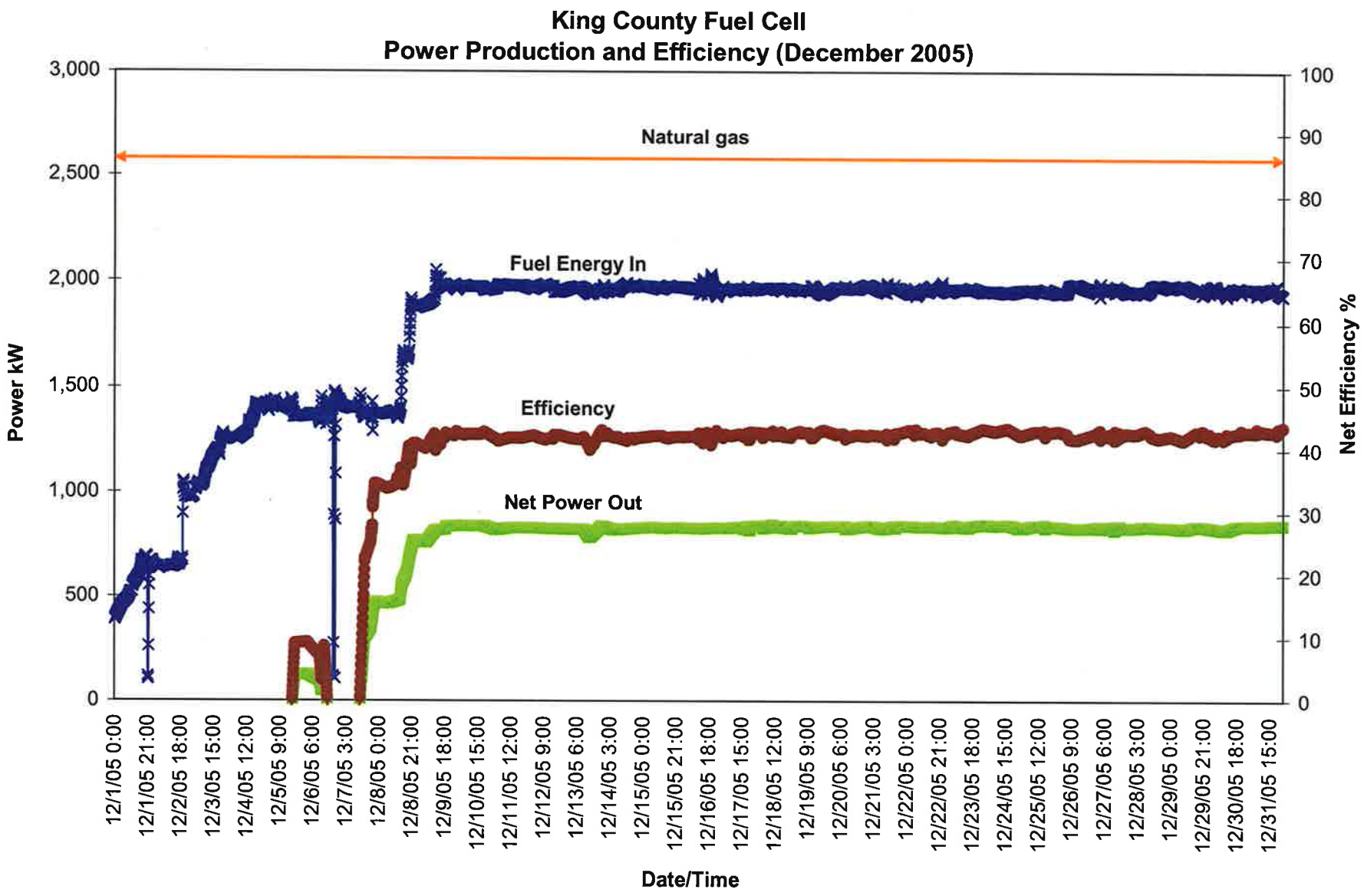
5/17/05 22:40
5/18/05 19:00
5/19/05 15:20
5/20/05 11:40
5/21/05 8:00
5/22/05 4:20
5/23/05 0:40
5/23/05 21:00
5/24/05 17:20
5/25/05 13:40
5/26/05 10:00
5/27/05 6:20
5/28/05 2:40
5/28/05 23:00
5/29/05 19:20
5/30/05 15:40


King County Fuel Cell
Power Production and Efficiency (June 2005)
Power kW
Net Efficiency %
Date/Time
DG
NG
Fuel Energy In
Efficiency
Net Power Out
NG - Natural gas
DG - Digester gas
3,000
2,500
2,000
1,500
1,000
500
0
100
90
80
70
60
50
40
30
20
10
0
6/1/05 0:00
6/1/05 20:20
6/2/05 16:40
6/3/05 13:00
6/4/05 9:20
6/5/05 5:40
6/6/05 2:00
6/6/05 22:20
6/7/05 18:40
6/8/05 15:00
6/9/05 11:20
6/10/05 7:40
6/11/05 4:00
6/12/05 0:20
6/12/05 20:40
6/13/05 17:00
6/14/05 13:20
6/15/05 9:40
6/16/05 6:00
6/17/05 2:20
6/17/05 22:40
6/18/05 19:00
6/19/05 15:20
6/20/05 11:40
6/21/05 8:00
6/22/05 4:20
6/23/05 0:40
6/23/05 21:00
6/24/05 17:20
6/25/05 13:40
6/26/05 10:00
6/27/05 6:20
6/28/05 2:40
6/28/05 23:00
6/29/05 19:20
6/30/05 15:40


King County Fuel Cell
Power Production and Efficiency (Third Quarter 2005)
Fuel Cell Module Replacement and Control Logic Modifications - No Power Generation
Power kW
3,000
2,500
2,000
1,500
1,000
500
0
Net Efficiency %
100
90
80
70
60
50
40
30
20
10
0
Date/Time

King County Fuel Cell
Power Production and Efficiency (October - November 2005)


King County Fuel Cell
Power Production and Efficiency (December 2005)
Natural gas
Fuel Energy In
Efficiency
Net Power Out
Power kW
Net Efficiency %
Date/Time
3,000
2,500
2,000
1,500
1,000
500
0
100
90
80
70
60
50
40
30
20
10
0
12/1/05 0:00
12/1/05 21:00
12/2/05 18:00
12/3/05 15:00
12/4/05 12:00
12/5/05 9:00
12/6/05 6:00
12/7/05 3:00
12/8/05 0:00
12/8/05 21:00
12/9/05 18:00
12/10/05 15:00
12/11/05 12:00
12/12/05 9:00
12/13/05 6:00
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12/26/05 9:00
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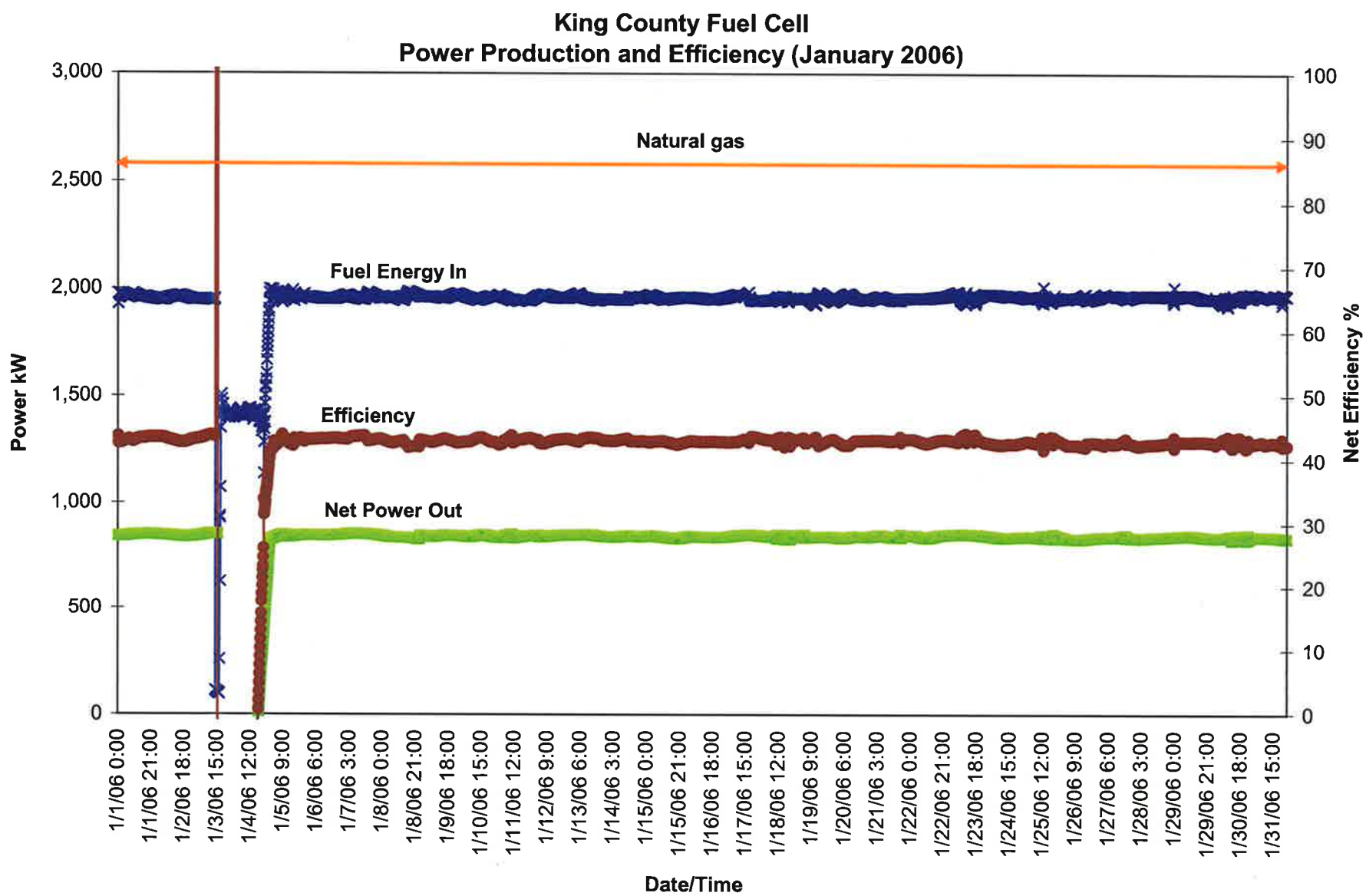
12/30/05 18:00
12/31/05 15:00


King County Fuel Cell
Power Production and Efficiency (January 2006)
Natural gas
Fuel Energy In
Efficiency
Net Power Out
Power kW
Net Efficiency %
Date/Time
3,000
2,500
2,000
1,500
1,000
500
0
100
90
80
70
60
50
40
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20
10
0
1/1/06 0:00
1/1/06 21:00
1/2/06 18:00
1/3/06 15:00
1/4/06 12:00
1/5/06 9:00
1/6/06 6:00
1/7/06 3:00
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1/8/06 21:00
1/9/06 18:00
1/10/06 15:00
1/11/06 12:00
1/12/06 9:00
1/13/06 6:00
1/14/06 3:00
1/15/06 0:00
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1/16/06 18:00
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1/18/06 12:00
1/19/06 9:00
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1/21/06 3:00
1/22/06 0:00
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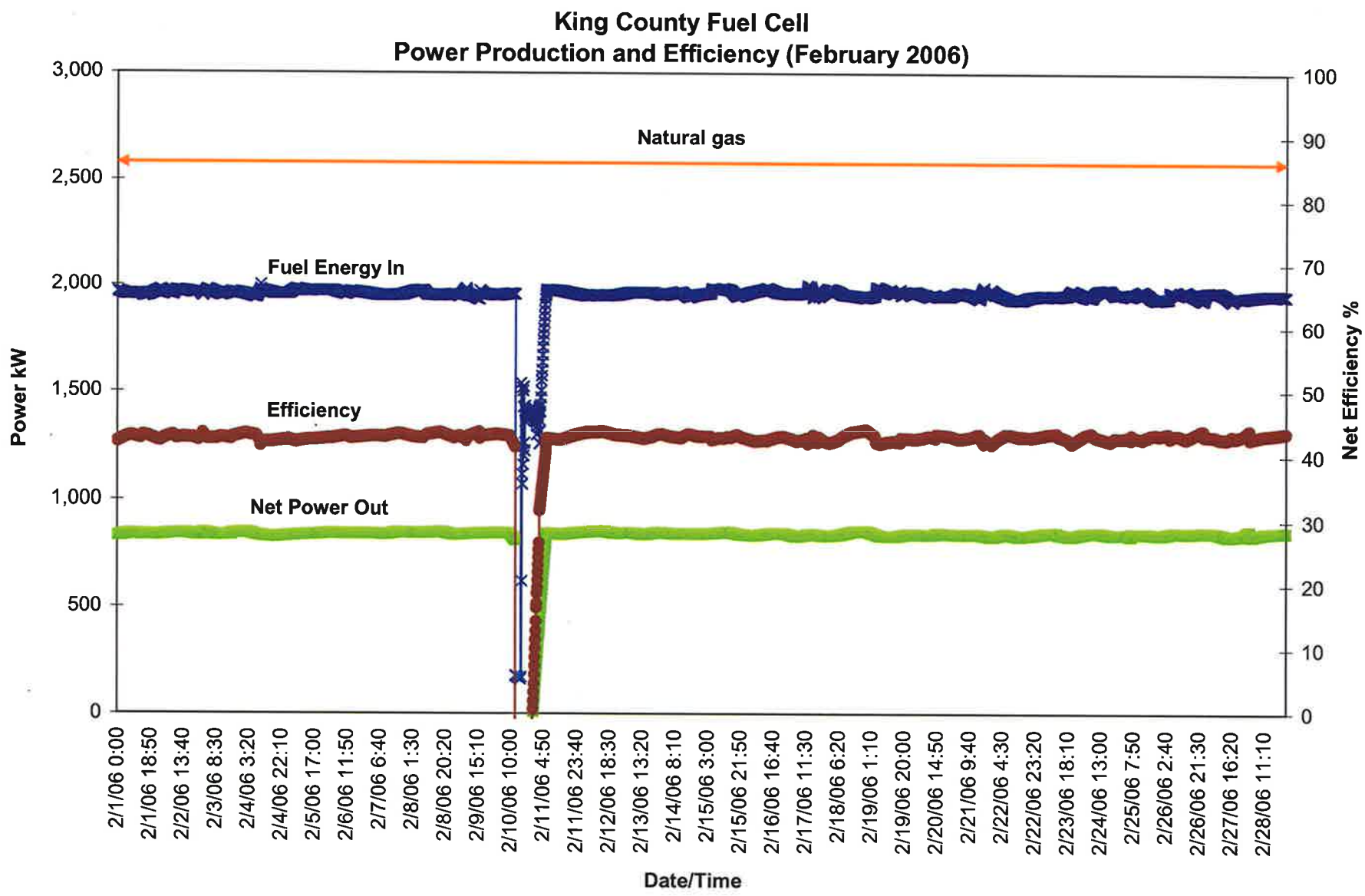
1/31/06 15:00


King County Fuel Cell
Power Production and Efficiency (February 2006)
Natural gas
Fuel Energy In
Efficiency
Net Power Out
Power kW
Net Efficiency %
Date/Time
3,000
2,500
2,000
1,500
1,000
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0
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2/1/06 0:00
2/1/06 18:50
2/2/06 13:40
2/3/06 8:30
2/4/06 3:20
2/4/06 22:10
2/5/06 17:00
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2/7/06 6:40
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2/11/06 23:40
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2/14/06 8:10
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2/16/06 16:40
2/17/06 11:30
2/18/06 6:20
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2/19/06 20:00
2/20/06 14:50
2/21/06 9:40
2/22/06 4:30
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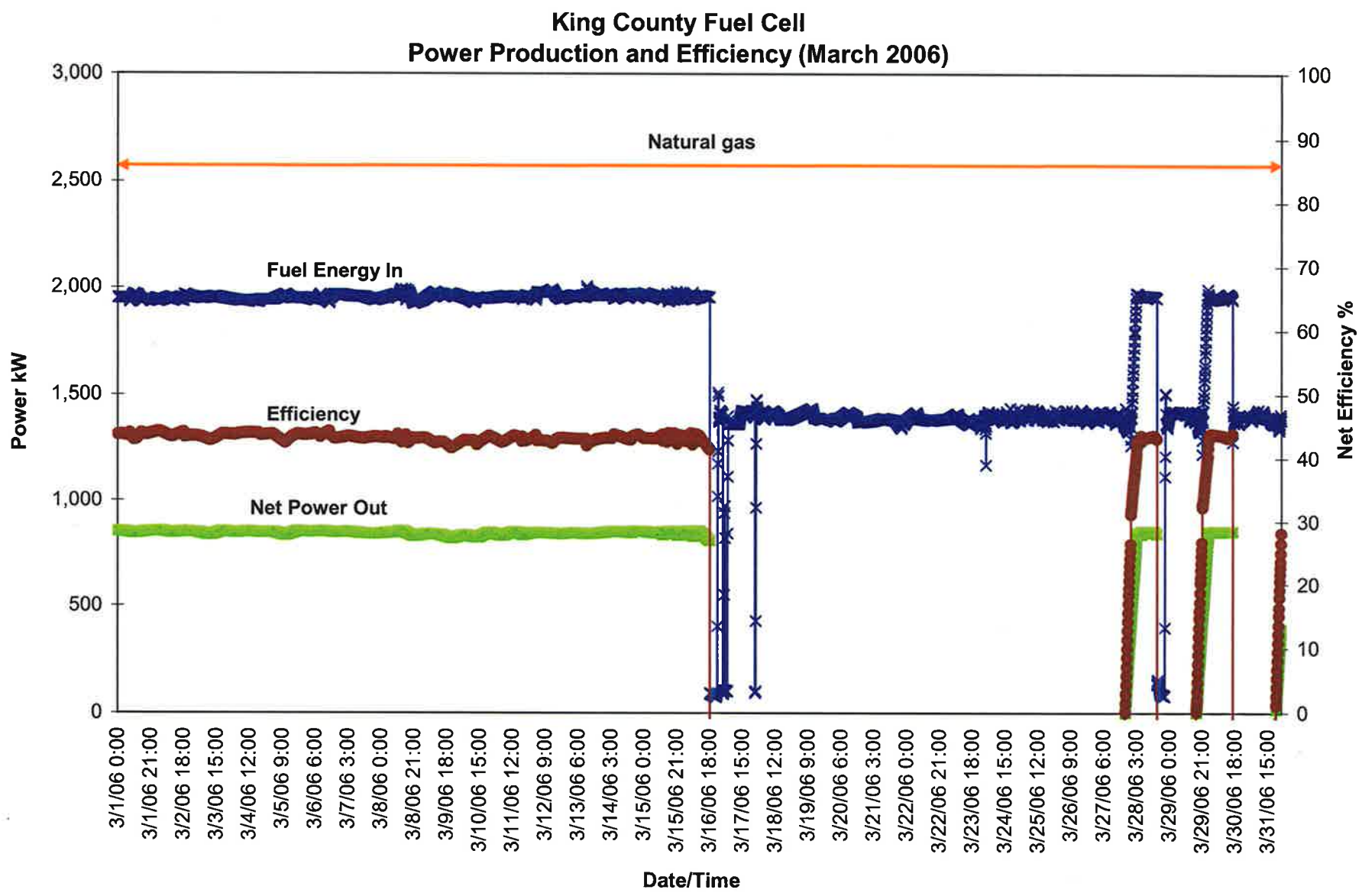
2/23/06 18:10
2/24/06 13:00
2/25/06 7:50
2/26/06 2:40
2/26/06 21:30
2/27/06 16:20
2/28/06 11:10


King County Fuel Cell
Power Production and Efficiency (March 2006)
Natural gas
Fuel Energy In
Efficiency
Net Power Out
Power kW
Net Efficiency %
Date/Time
3,000
2,500
2,000
1,500
1,000
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0
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3/1/06 0:00
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3/2/06 18:00
3/3/06 15:00
3/4/06 12:00
3/5/06 9:00
3/6/06 6:00
3/7/06 3:00
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3/8/06 21:00
3/9/06 18:00
3/10/06 15:00
3/11/06 12:00
3/12/06 9:00
3/13/06 6:00
3/14/06 3:00
3/15/06 0:00
3/15/06 21:00
3/16/06 18:00
3/17/06 15:00
3/18/06 12:00
3/19/06 9:00
3/20/06 6:00
3/21/06 3:00
3/22/06 0:00
3/22/06 21:00
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3/27/06 6:00
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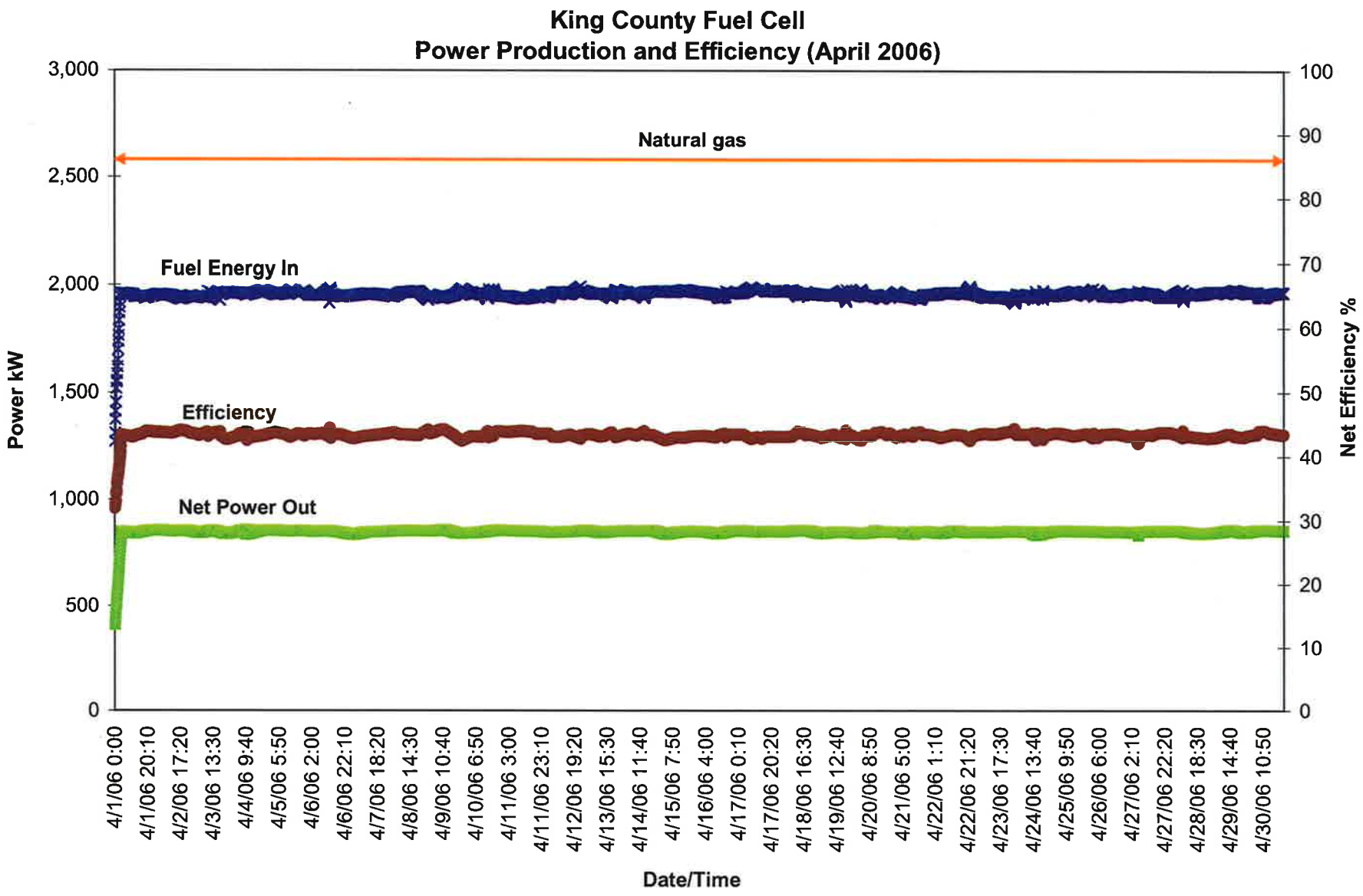
3/30/06 18:00
3/31/06 15:00


King County Fuel Cell
Power Production and Efficiency (April 2006)
Natural gas
Fuel Energy In
Efficiency
Net Power Out
Power kW
Net Efficiency %
Date/Time
3,000
2,500
2,000
1,500
1,000
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0
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4/1/06 0:00
4/1/06 20:10
4/2/06 17:20
4/3/06 13:30
4/4/06 9:40
4/5/06 5:50
4/6/06 2:00
4/6/06 22:10
4/7/06 18:20
4/8/06 14:30
4/9/06 10:40
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4/14/06 11:40
4/15/06 7:50
4/16/06 4:00
4/17/06 0:10
4/17/06 20:20
4/18/06 16:30
4/19/06 12:40
4/20/06 8:50
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4/22/06 1:10
4/22/06 21:20
4/23/06 17:30
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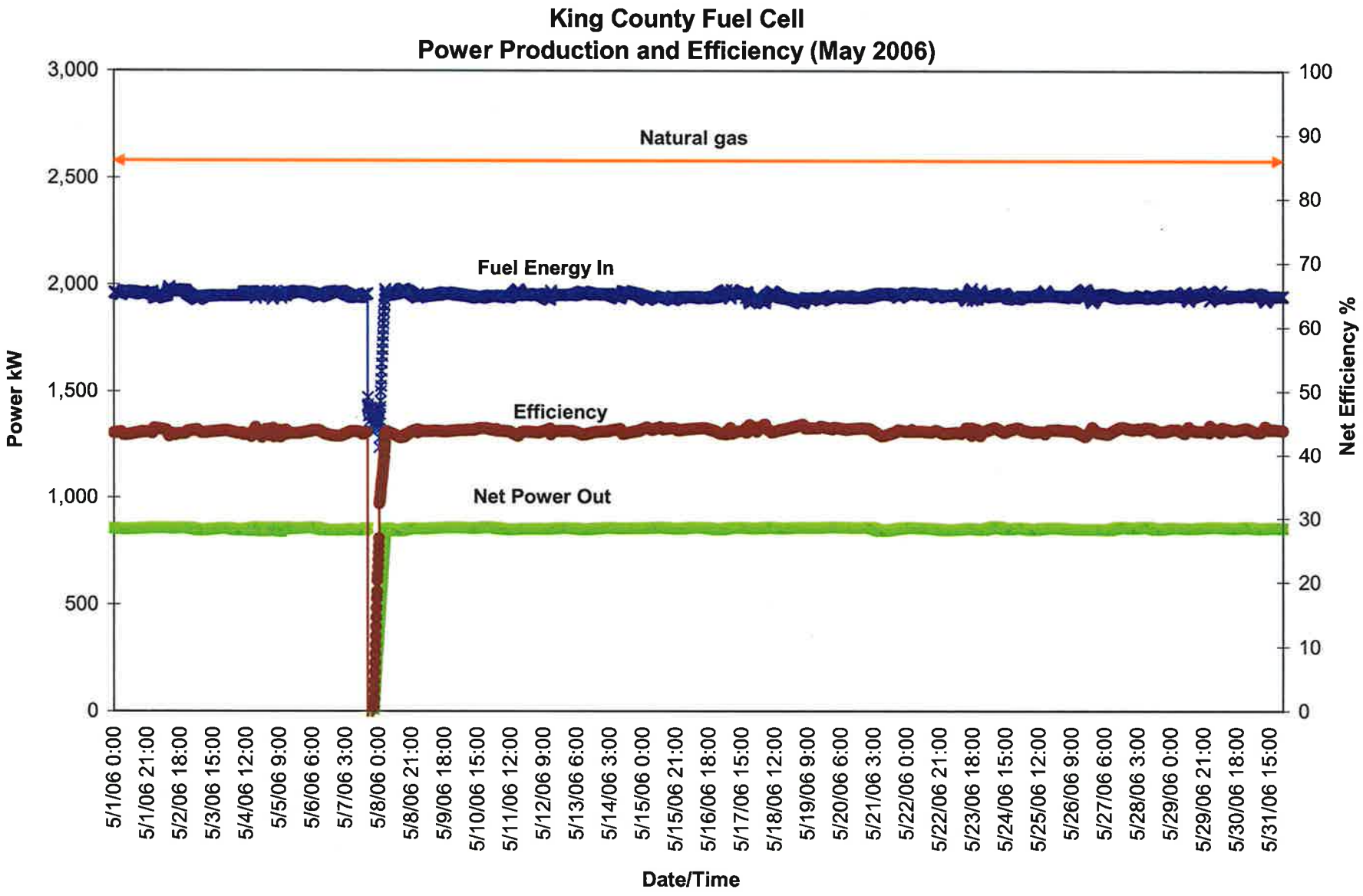
4/28/06 18:30
4/29/06 14:40
4/30/06 10:50


King County Fuel Cell
Power Production and Efficiency (May 2006)
Natural gas
Fuel Energy In
Efficiency
Net Power Out
Power kW
Net Efficiency %
Date/Time
3,000
2,500
2,000
1,500
1,000
500
0
100
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80
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5/1/06 0:00
5/1/06 21:00
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5/8/06 0:00
5/8/06 21:00
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5/10/06 15:00
5/11/06 12:00
5/12/06 9:00
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5/14/06 3:00
5/15/06 0:00
5/15/06 21:00
5/16/06 18:00
5/17/06 15:00
5/18/06 12:00
5/19/06 9:00
5/20/06 6:00
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5/22/06 21:00
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5/26/06 9:00
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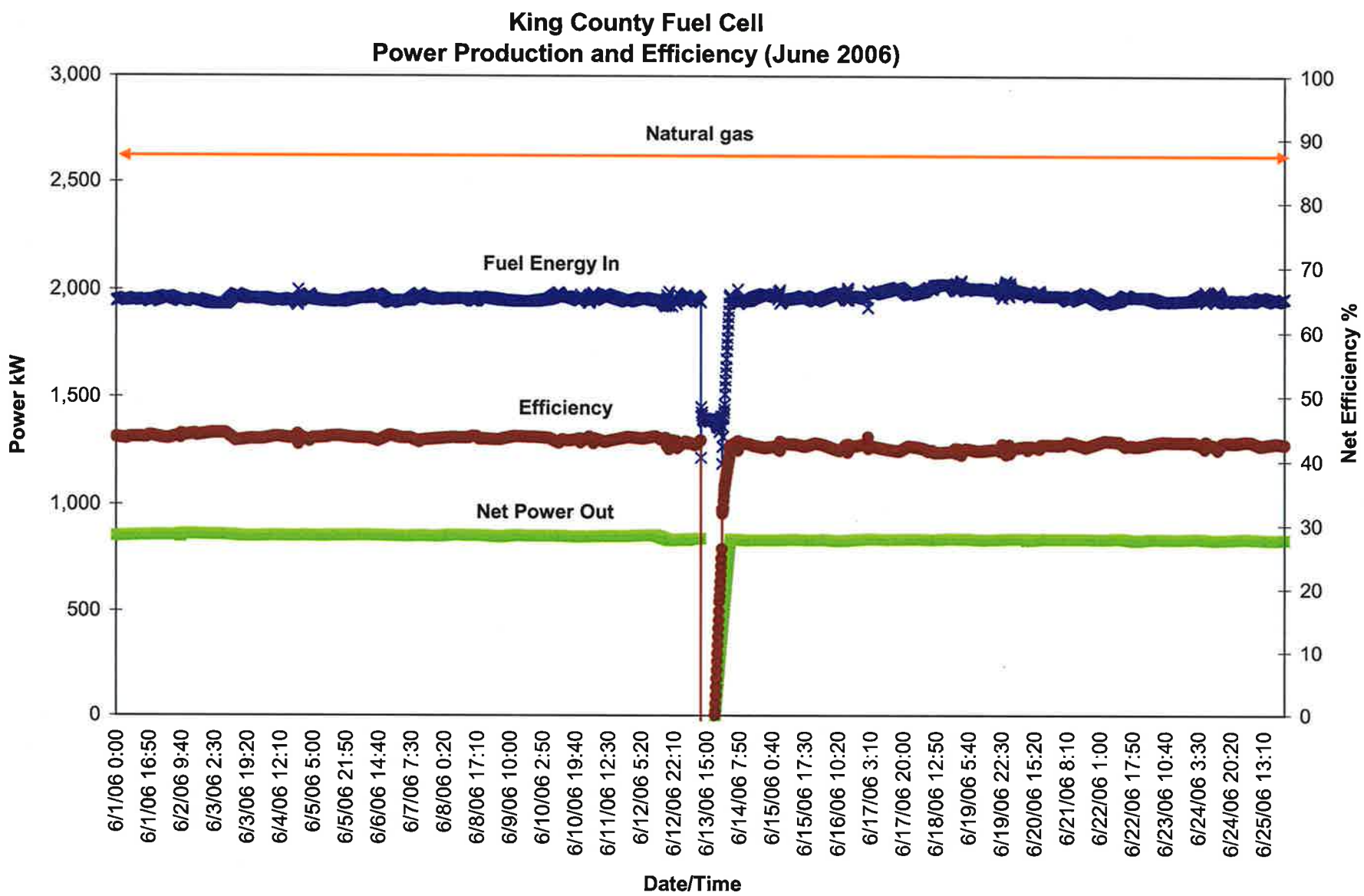
5/29/06 0:00
5/29/06 21:00
5/30/06 18:00
5/31/06 15:00


King County Fuel Cell
Power Production and Efficiency (June 2006)
Natural gas
Fuel Energy In
Efficiency
Net Power Out
Power kW
Net Efficiency %
Date/Time
3,000
2,500
2,000
1,500
1,000
500
0
100
90
80
70
60
50
40
30
20
10
0
6/1/06 0:00
6/1/06 16:50
6/2/06 9:40
6/3/06 2:30
6/3/06 19:20
6/4/06 12:10
6/5/06 5:00
6/5/06 21:50
6/6/06 14:40
6/7/06 7:30
6/8/06 0:20
6/8/06 17:10
6/9/06 10:00
6/10/06 2:50
6/10/06 19:40
6/11/06 12:30
6/12/06 5:20
6/12/06 22:10
6/13/06 15:00
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6/15/06 17:30
6/16/06 10:20
6/17/06 3:10
6/17/06 20:00
6/18/06 12:50
6/19/06 5:40
6/19/06 22:30
6/20/06 15:20
6/21/06 8:10
6/22/06 1:00
6/22/06 17:50
6/23/06 10:40
6/24/06 3:30
6/24/06 20:20
6/25/06 13:10

Appendix F
Demonstration Project
Public Outreach Summary

Public Outreach

Publications and Presentations

Publishing and presenting data about the fuel cell project has occurred regularly throughout the demonstration period. The papers and presentations given during the reporting period are described below.

Poster. *Sustainable On-Site Power Generation using a 1 MW Fuel Cell and Digester Gas,* , Jaimie Hennessy, Eleanor Allen, Greg Bush, Dave Hennessy, WEF Technology 2005, Second Joint Specialty Conference for Sustainable Management of Water Quality Systems for the 21st Century, San Francisco, California, August 2005.

Paper and Presentation. *Lessons Learned from the World's Largest Digester Gas Fuel Cell,* Eleanor Allen, Jaimie Hennessy, Greg Bush, Carol Nelson, Dave Hennessy, WEFTEC 2005, Washington, D.C., October 2005.

Presentation. *Fuel Cell Demonstration Project,* Greg Bush, Pacific Northwest Clean Water Association, Tacoma, Washington, November, 2005.

Presentation, Fuel Cell Demonstration Project, Association of Washington Cities, Yakima, WA, August 2001

Paper and Presentation, Fuel Cell Demonstration Project, Greg Bush, American Institute of Chemical Engineers, New Orleans, LA, March 2002

Presentation, Fuel Cell Demonstration Project, Greg Bush, Water Environment Federation Bio-Energy Technical Committee, Tulane University, New Orleans, LA, August 2003

Paper and Presentation, Fuel Cell Demonstration Project, NW Biosolids Management Association, Chelan, WA, September 2003

Presentation, Fuel Cell Demonstration Project, «GreetingLine», Hydrogen Learning Workshop, Portland, OR, August 2004

Presentation, Fuel Cell Demonstration Project, «GreetingLine», Waste Heat to Power Workshop, National Academy of Sciences, Irvine, CA, February 2006

Presentation, Fuel Cell Demonstration Project, «GreetingLine», Washington State Recycling Association, Spokane, WA, May 2006

Awards

The King County Fuel Cell Demonstration Project received the 2005 Research and Technology Award from the National Association of Clean Water Agencies. The award was announced at the association's annual conference in Washington, D.C., May 2005.

King County Fuel Cell Demonstration

Project Summary • March 2008

FuelCell Energy

BACKGROUND

Fuel Cell Demonstration Project site at the South Treatment Plant

Working with the U.S. Environmental Protection Agency and FuelCell Energy, Inc., King County sponsored the world's largest demonstration project of a single-unit fuel cell power plant. Using digester gas from the county's South Wastewater Treatment Plant in Renton, WA, the fuel cell was operated during a two-year demonstration project. The fuel cell power plant was sized to produce 1 megawatt (MW) of electricity and designed to capture additional waste heat for recycle to the treatment plant hot water system.

King County began its investigation of fuel cells for electrical power generation in 1997. FuelCell Energy, Inc. was selected in 2000 to design and construct a molten carbonate fuel cell power plant. Two project goals were established to measure fuel cell performance during the demonstration period – (1) demonstrate that the molten carbonate fuel cell technology can be adapted to use anaerobic digester gas as a fuel source and (2) achieve a nominal plant power output target of 1 MW (net AC) using either digester gas (DG) or natural gas (NG).

Project Timeline

September Project planning initiated

July FuelCell Energy selected for the project

October Fabrication of fuel cell stack initiated

April Startup

1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006

September Design of fuel cell initiated

April Construction of the fuel cell at the South Treatment Plant initiated

Two-year demonstration period

Operation – Year 1

- 1-MW operation on NG and DG
- Emission and noise testing
- Incorporatation of auto fuel switchover
- One month waste heat recovery
- DG condensation problems

Operation – Year 2

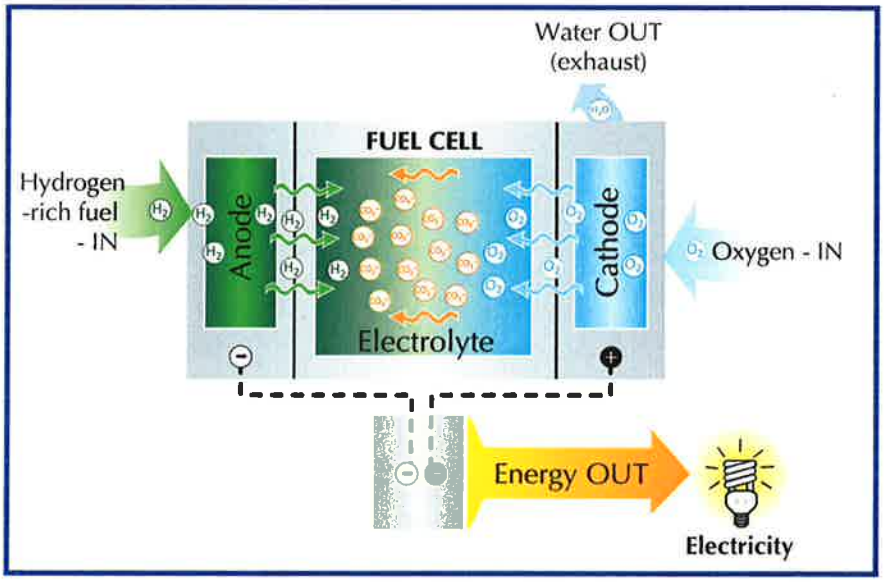
- Stack failure and replacement
- Stack replaced within 30 days
- 850-kW capacity (derated from 1-MW)
- Off-line due to non-related construction
- Continued problems with DG condensate
- NG operation for remainder of project

PROCESS FUNDAMENTALS

How Does a Fuel Cell Work?

Fuel cells are electrochemical devices that convert chemical energy from fuels containing hydrogen directly to electricity and heat. Combustion is not needed.

Similar to a battery, a fuel cell has hundreds of individual cells. Cells are grouped to form a stack. Each fuel cell contains an anode, cathode, and electrolyte. A hydrogen-rich fuel, such as digester gas, enters each stack and reacts with oxygen in the air to produce electricity in each cell.



A typical battery has a fixed supply of energy. But fuel cells are like large continuously operating batteries that generate electricity as long as they get a fuel, such as methane, which is a large component of digester gas.

Fuel Cell Advantages: High Efficiency, Low Emissions

Electricity is typically generated in a two-step process: Fuel is combusted to produce mechanical energy (or heat), which then turns a generator to produce electricity. Fuel cells convert fuel directly to electricity. By dropping the mechanical energy step, fuel cells are more efficient than traditional methods of generating electricity and produce very low emissions.

Molten Carbonate Fuel Cells

Fuel cells are defined by their electrolyte, or the material inside them. There are five types of commercial fuel cells: solid oxide, phosphoric acid, alkaline, proton exchange membrane and molten carbonate. King County's South Treatment Plant used the molten carbonate fuel cell (MCFC) which operates at 1,100° F and is designed with reforming (conversion of methane to hydrogen) incorporated into the fuel cell stack. The fuel cell power plant components included fuel scrubbing, fuel processing, power production, power inverter, and heat recovery (reference fuel cell process flow diagram).

Molten Carbonate Fuel Cell Chemistry

$$\underset{\text{(Digester Gas)}}{CH_4} + \underset{\text{(Purified Water)}}{2H_2O} \rightarrow CO_2 + 4H_2 \quad \text{(Reformer)}$$

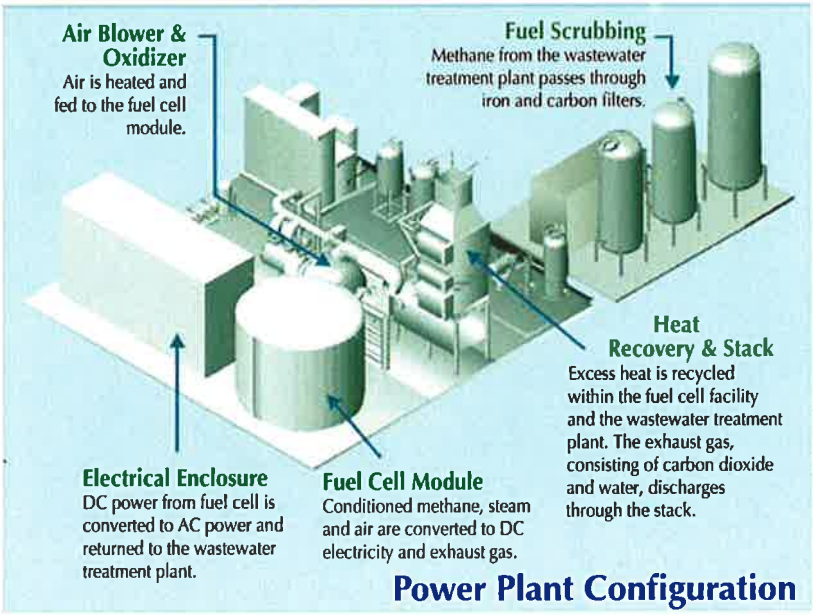
$$+$$

$$H_2 + 1/2O_2 \rightarrow H_2O \quad \text{(Fuel Cell)}$$

$$CH_4 + 2O_2 \rightarrow \underbrace{CO_2 + 2H_2O}_{\text{Stack Exhaust}} \quad \text{(Overall)}$$

DEMONSTRATION POWER PLANT OPERATION

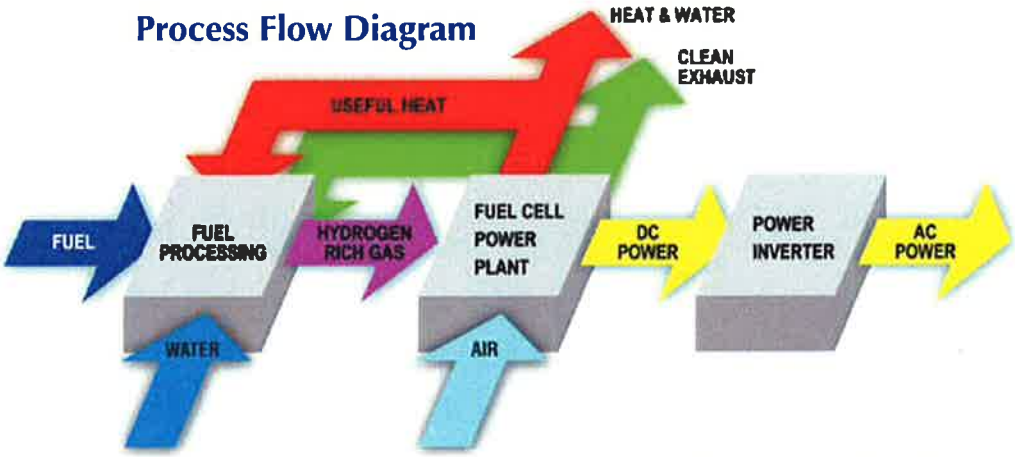
Fuel Cell Module
(4-stack assembly)



Source: Brown and Caldwell

Power Plant Configuration
(1/4-acre site at South Plant)

Process Flow Diagram



Demonstration Power Plant
Operating Conditions at 1MW Net Output

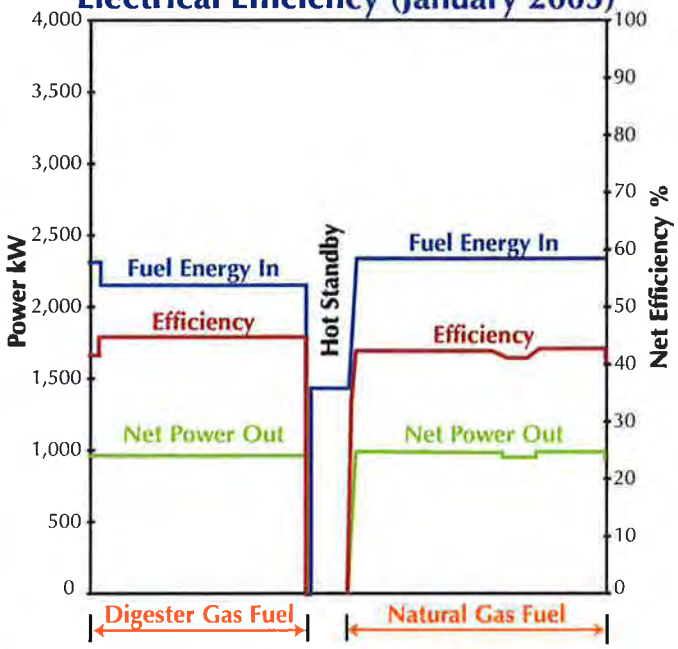
Digester Gas	
Gas Flow	225 scfm
Lower Heating Value	550 Btu/ft3
Methane Content	60 %
Carbon Dioxide Content	38 %
Natural Gas	
Gas Flow	140 scfm
Lower Heating Value	900 Btu/ft3
Methane Content	98 %
Carbon Dioxide Content	0 %
Water	
Water Flow	2.5 gpm

DEMONSTRATION POWER PLANT OPERATION (continued)

Demonstration Power Plant Performance

Operating Time	
Digester Gas Fuel *Natural Gas Fuel*	2,226 hr 8,507 hr
Power Generation	
Digester Gas *Natural Gas*	2.1 million kWh 7.1 million kWh
Power Output	
(2% stack de-rating every 6 months)	850 – 1,000 kW
Electrical Efficiency	
Digester Gas Natural Gas	44 – 46 % 42 – 45 %
Overall Efficiency	
Electrical + waste heat recovery	58 – 61 %
Emissions	
CO *NOx* *NMHC*	<= 13 ppm <= 0.2 ppm < 1 ppm

Fuel Cell Power Production and Electrical Efficiency (January 2005)



DEMONSTRATION PROJECT OBSERVATIONS AND CONCLUSIONS

Based on the two-year operating period, project operation and maintenance observations include:

- The project represented a successful research and development effort.
- The power plant control system was modified to provide automated fuel source switching and to respond to process transients.
- The power plant subsystem configurations are being modified in future fuel cell designs based on the demonstration operating experience.
- Appropriate selection of a stable methane source in the wastewater treatment plant digester gas system is critical to reliable operation of the fuel cell power plant.
- The power plant had numerous components requiring frequent maintenance and high replacement cost (fuel cell stack life of < 3 years).
- The operation of the power plant was highly automated.

Alternative formats available

206-684-1247 or 711 (TTY relay)

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Project Partners

FuelCell Energy of Danbury, CT ($9.4M), the U.S. Environmental Protection Agency ($8.6M), and King County ($2.3M) provided financial support for the South Treatment Plant Fuel Cell Demonstration Project. The U.S. Environmental Protection Agency provided the federal funds to King County through annual cooperative agreements. The total value of the project was $20.3 million.

CH2M HILL of Bellevue, WA, and Brown & Caldwell of Seattle, WA, provided engineering services to King County for the fuel cell project. Hawk Mechanical Contractors, Inc. of Redmond, WA, installed the fuel cell.

King County

Department of Natural Resources and Parks
Wastewater Treatment Division
Planning and Compliance Section

Fuel Cell Demonstration Project
201 South Jackson Street, Suite 512
Seattle, WA 98104-3855
206-263-3883 or 711 (TTY relay)
http://dnr.metrokc.gov/wtd/fuelcell/

World's Largest Biogas-Powered Fuel Cell

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Concept

Combustion Chemistry without the Flame

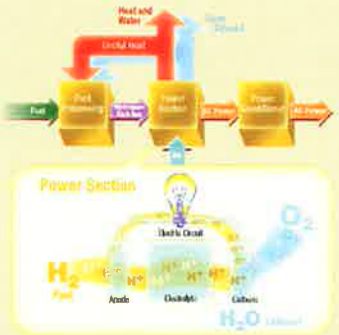
Fuel cells produce electricity by combining hydrogen and oxygen to form water. Since hydrogen does not exist on earth in elemental form, it must be manufactured, typically from fossil fuels. By separating the combustion reaction into two steps, fuel cells generate fewer byproduct emissions and produce electricity more efficiently than traditional power generating equipment.

Teamed with USEPA and FuelCell Energy, King County (Seattle metropolitan area) installed a molten carbonate fuel cell in its South Treatment Plant. Connected to the plant's digester gas system, the fuel cell began operation in June 2004. At Year 1 of the two-year demonstration period, *project objectives* have been met:

- Demonstrate molten carbonate technology on digester gas
- Generate nominal 1 MW (net AC) with both natural and digester gas

During Year 2, a waste heat recovery system will be tested in an attempt to raise the overall thermal efficiency. The recovered heat will be returned to the digesters. Additionally, treatment plant staff will continue to gain experience operating the fuel cell. King County plans to continue operating the fuel cell beyond the demonstration period.

Follow our progress at
http://dnr.metrokc.gov/wtd/fuelcell



Molten Carbonate Fuel Cell Diagram

Fuel cells are similar to rechargeable batteries, which are discharged and then recharged, except fuel cells require a constant fuel source (i.e., constant recharging) and continuously generate electricity. Methane from either natural gas or digester gas enters the fuel processing stage. The fuel is preheated, partially reformed, and then flows to the anode. The reforming reaction (hydrogen formation) is completed in the fuel cell stack. Air flows through the cathode. Hydrogen splits into electrons and protons at the anode, and the electrons leave the fuel cell. The electrons return at the cathode, react with oxygen, and form water.

Implementation

Design

Manufacturing

Factory Testing

Delivery

Operation

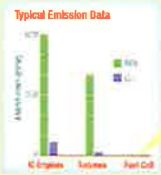
Lessons Learned

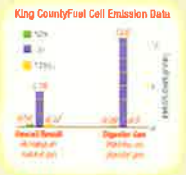
- Fuel cell performs well and operates reliably. 4.3M kWhrs of electricity generated (2.7M on NG and 1.6M on Biogas) during 5,700 hours of runtime (3,600 on NG and 2,100 on biogas). Operating on natural gas, the fuel cell 96% available, on digester gas, 83% available.
- Permitting efforts mixed. Building and air permits easily obtained but electrical permit and interconnect agreement required considerable time and energy.
- Fuel cell is sensitive to gas quality. Spikes in methane content are the main reason for shutdowns.
- Capital cost is decreasing, but still high relative to traditional power generating technologies. Total budget for project approximately $22.6 million ($12.5M USEPA, $8.4M FCE, $3.9M KC). Subsidies and regulatory drivers are currently required to make fuel cell technology cost effective. Even with the cost hurdle, worldwide fuel cell sales are growing.

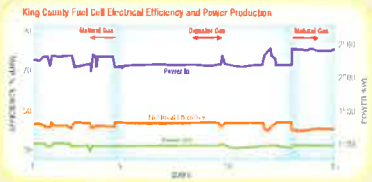
Performance

Emissions

- Emission data demonstrate lower NOx, CO, and VOC concentrations.
- No VOCs were detected while operating on digester gas.
- Methane breakthrough did occur, ~250 ppm for natural gas and ~290 ppm for digester gas.





Efficiency

- The fuel cell operates at higher efficiencies. Current electrical efficiency is approximately 43%.
- Operation of the waste heat recovery system will capture 1.7 MMBtu/hr, raising the thermal efficiency to approximately 65%.