ERDC/CERL TR-00-34

US Army Corps of Engineers®
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Molten Carbonate Fuel Cells (MCFCs) for Department of Defense Applications

Rock Island Arsenal MCFC

Franklin H. Holcomb, Michael J. Binder, William R. Taylor, Vincent Petraglia, Ron Ishii, John Klingenberg, Benjamin Sliwinski, Lowell Griffith, and Dharam Punwani

November 2000

Construction Engineering Research Laboratory

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Foreword

This study was conducted for the Office of the Director of Defense Research and Engineering (DDR&E) under AT47, "Congressional funding;" Work Unit No. BP8, "Molten Carbonate Fuel Cells." The technical monitor was Robert L. Boyd, ODDR&E.

The work was performed by the Energy Branch (CF-E), of the Facilities Division (CF), Construction Engineering Research Laboratory (CERL). The CERL Principal Investigator was Franklin H. Holcomb. Jon R. Klingenberg, of Illinova Energy Partners, provided overall direction of the site feasibility study described in this report. Acknowledgement must be given to the following Rock Island Arsenal personnel for their valuable contributions to this study: Dave Osborn, Jimmy Braden, Gary Cook, Dana Johnson, Bob Pettit, Chuck Swynenberg, Steve Rose, and Norm Hatcher. Appreciation is expressed to Joseph Scroppo, Vincent Petraglia, and Robert Petkus, of M-C Power for providing details on prototype fuel cell performance and review of this report. Ron Ishii, of Alternative Energy Systems Consulting, Inc. (AESC), reviewed this report and made valuable suggestions for improvements. Part of this work was done by M-C Power Corporation under contract No. DACA88-99-C-0010. Larry M. Windingland is Chief, CEERD-CF-E, and L. Michael Golish is Chief, CEERD-CF. The technical editor was William J. Wolfe, Information Technology Laboratory.

CERL is an element of the U.S. Army Engineer Research and Development Center (ERDC), U.S. Army Corps of Engineers. The Director of ERDC is Dr. James R. Houston and the Commander is COL James S. Weller.

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1 Introduction

Background

Located on a 946 acre island in the upper Mississippi River, Rock Island Arsenal (RIA) is the largest government-owned weapons manufacturer arsenal in the western world (Figure 1). The Arsenal manufactures gun mounts, artillery carriages, recoil mechanisms, and other equipment for the Armed Forces as well as assembling tools, sets, kits, and outfits that support equipment in the field. The Arsenal's stone buildings are also the home to approximately 40 tenant organizations that receive facility support services such as general supply purchasing, security, information technology, and building and infrastructure maintenance. RIA's three major missions are: (1) manufacturing, (2) logistics, and (3) base operations.

The Arsenal's reputation for machining excellence has attracted work orders from all branches of the U.S. Armed Forces and its allies. Every phase of manufacturing development and production is available in the modern Kingsbury Manufacturing Complex. Prototypes are fabricated by specially trained machinists. Limited initial production, total production, and spare and repair parts production are accomplished throughout the state-of-the-art facility. Arsenal-made products include artillery, gun mounts, recoil mechanisms, small arms, aircraft weapons sub-systems, grenade launchers, weapons simulators, and a wide variety of associated spare and repair parts.

The Arsenal's success in its logistics mission has made it a major supplier of the military's tool sets, kits, and basic issue items. Trained logistics personnel fabricate and assemble large scale tool sets ranging in size from carrying-case tool sets to fully equipped shelters. Assembled tool sets are critical to the soldiers as they repair and maintain a variety of systems, vehicles, and other support items on the field. Basic Issue Items sets for major end items are also fabricated and assembled at the Arsenal's Logistics Center.

The Arsenal's third mission is to provide support to its approximately 40 tenants and their 4000 employees. Arsenal personnel provide expertise in purchasing, information management, personnel administration, communications, building maintenance, fire protection, and security.

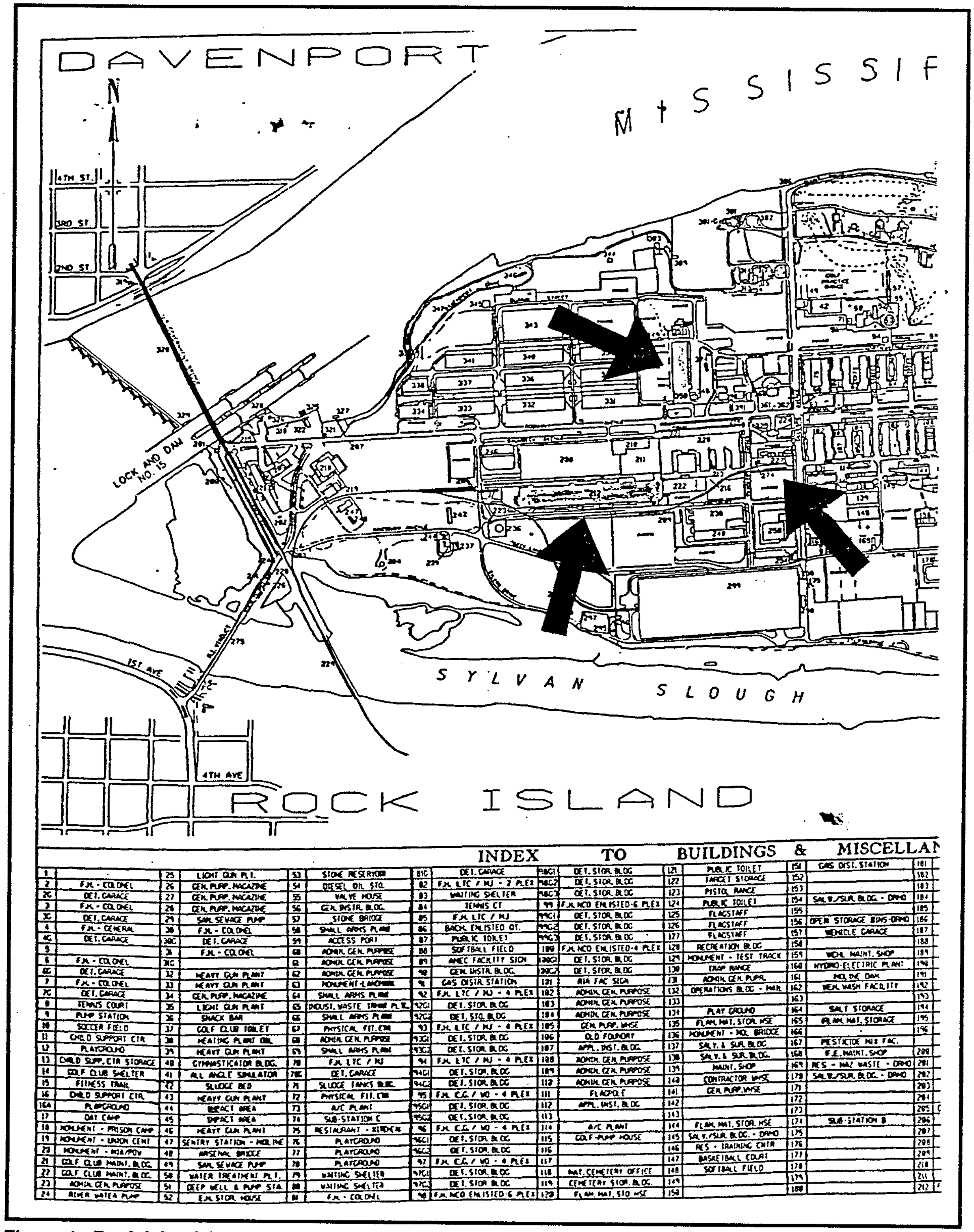

Figure 1. Rock Island Arsenal installation map.

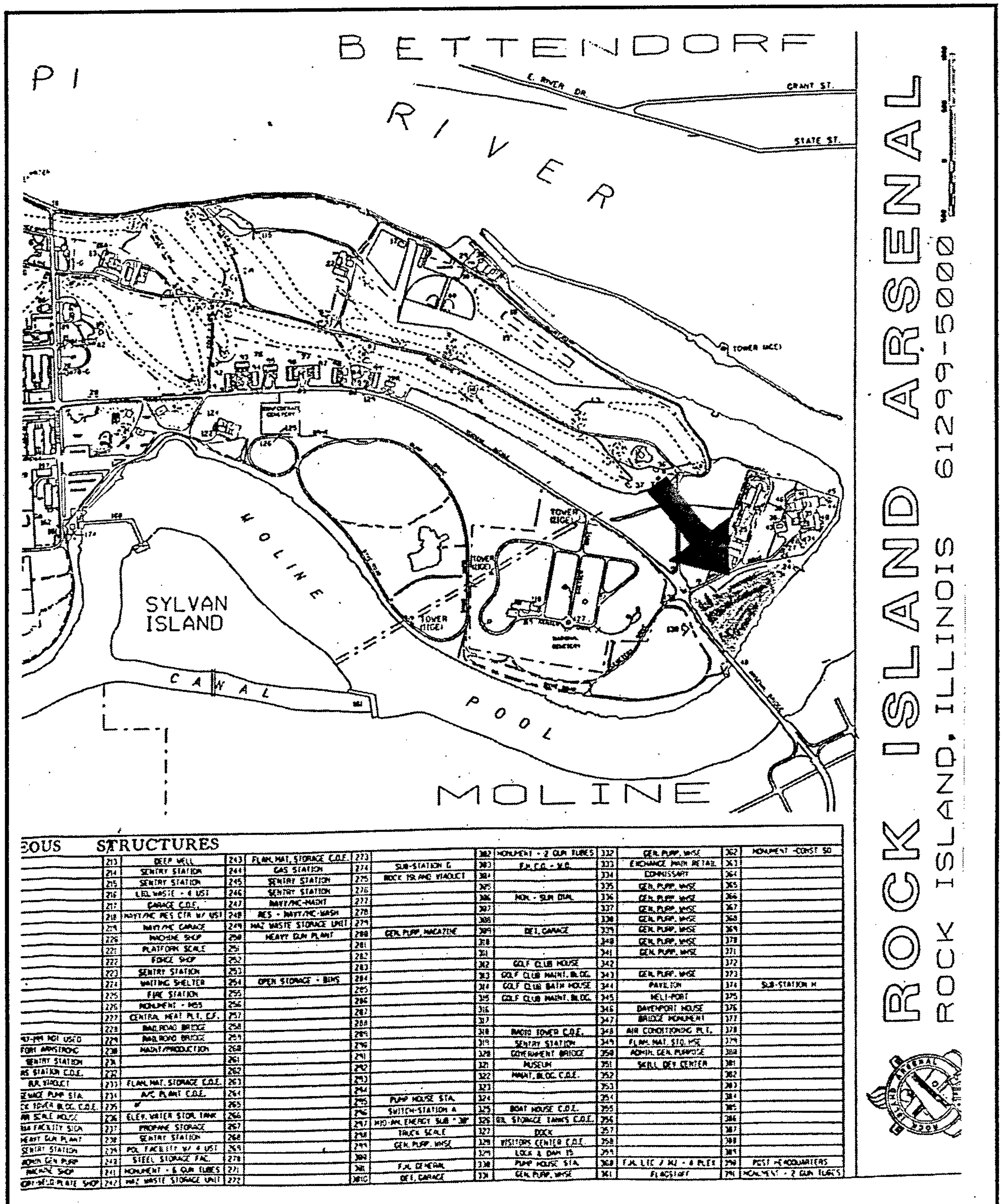

Figure 1. (Cont'd).

In this study, the U.S. Army Construction Engineering Research Laboratory (CERL) evaluated the feasibility of siting a 1 MW molten carbonate fuel cell (MCFC) at RIA. The study was conducted in three phases.

Phase I

The first phase of the fuel cell feasibility study surveyed four potential sites at Rock Island Arsenal previously identified through discussions among the project participants. Phase I identified a location near the Central Steam plant as the most favorable site, and concluded that the fuel cell should be grid connected, supplying electrical energy to the entire installation, rather than a specific building or facility. Phase I also identified numerous opportunities for use of waste heat recovered from the fuel cell, including plating operations located reasonably close to the central plant site and accessible through the summer steam distribution system. Phase I study also reviewed future plans for the central heating plant. RIA is currently examining the possibility of reducing or eliminating operation of the central plant.

To accomplish this, RIA has initiated a study of the feasibility of applying ground source heat pumps and package boilers to serve the heating and cooling loads presently met by the central plant. At the time of this writing, RIA was collaborating with Oak Ridge National Laboratory to evaluate and select a contractor to perform the geothermal heat pump feasibility study. Because of the timing of the RIA geothermal feasibility study and this work effort, it was not possible to directly incorporate the RIA heat pump analysis within this report. This report does, however, consider implications of the possible central plant closure, and also how the fuel cell might favorably interact with an RIA energy system using geothermal heat pumps.

Phase II

Phase II of this study, completed in December of 1999, examined in detail the location near the Central Steam plant. An important assumption of the Phase II study was that the fuel cell be grid connected, supplying electrical energy to the entire installation rather than to a specific building or facility. In addition, the fuel cell would cogenerate and supply heat that would augment the Central Heating Plant steam load, thus displacing some coal purchases. In Phase II, the research team evaluated the system's reliability and estimated the economic and environmental benefits that may be realized through the installation of the fuel cell power plant.

Phase II also assessed the implications of plans for the central heating plant. To fully examine the possibility of reducing or eliminating central plant operation, Phase II considered the possible central plant closure and also how the fuel cell might favorably interact with a RIA energy system by using geothermal heat pumps.

Phase III

Phase III performed detailed modeling of the fuel cell potential cost and environmental benefits specific to RIA's energy situation. Because of the complexity and interaction of RIA's process and environmental energy consumption along with associated costs, the model captures energy loads, RIA local generation, and fuel prices to ascertain the fuel cell's impact at a known level of certainty.

Objectives

The overall objective of this study was to investigate the feasibility of siting a 1 MW molten carbonate fuel cell at Rock Island Arsenal. The specific objective of Phase I of the study was to summarize relevant MCFC siting data for each of the four candidate sites at Rock Island Arsenal. The objective of Phase II was to provide a more detailed description of fuel cell siting characteristics, interface requirements, and preliminary design details. A further Phase II objective was to analyze and define load management benefits resulting from application of the fuel cell, interactions with installed ground source heat pumps, and electrical and thermal energy conservation opportunities at RIA. The objective of Phase III was to provide a more detailed analysis of fuel cell benefits to RIA using the site specifics developed for the proposed MCFC site near the Central Heating Plant.

Approach

Phase I

Three site visits were made to Rock Island Arsenal to gather data on the characteristics of each site. Through discussions with M-C Power and Alternative Energy Systems Consulting, Inc. (AESC), a set of preliminary specifications were developed for the 1 MW fuel cell prototype under consideration. With these specifications and through further discussions with M-C Power, AESC, and CERL, a set of siting criteria was developed. Tables 1 and 2 list the 1 MW fuel cell specifications and siting criteria.

Table 1. Preliminary specifications for 1 MW fuel cell prototype (may consist of two 500 kW units).

Electric	
Interface voltage and phase connection	Inverter produced 480 V. 3-phase
Current rating of output terminals	Rated at 1,000 Amp, Nominal 693 Amp/500kW unit
Output terminal cable connection	Cable connectors
Connection cabinet	To be decided
Output metering	Included, specifications to be determined
Interface protection devices	Will conform to IEEE and NFPA codes
Step-up/isolation transformers	To be decided
Transfer switch for grid connection	To be decided
Natural Gas	
Minimum gas line pressure required	40 psig. A gas booster is required to increase gas pressure to powerplant to 105 psig. This unit will be provided with powerplant
Natural gas used per hour (maximum)	Heat rate is 6,560 Btu/kW-hr (LHV). (3.7 MM Btu/hr per 500 kW unit)
Utility grade natural gas acceptable	Yes, odorant type and quantities should be specified
Powerplant gas input meter	To be decided
Water	
Minimum water pressure	60 psig
Water quality required	potable water
Water flow required	2 gal/min.
Heat Recovery	
Thermal output	1.18 million Btus/hr
Steam pressure	Not specified, probably up to 150 psig
Temperature	Limited by 550 deg. F exhaust gas temperature
Foundations	
Size of powerplant	32 ft wide, 40 ft long, 13 ft high for each of two (2) units. (Note: each unit consists of three modules)
Total weight	175,000 lb per unit
Recommended footings and foundation	To be determined
Site	
Site dimensions	52 ft wide, 60 ft long for each of two units. Total area approx. 6240 sq ft
Fence required	Yes
Horizontal and vertical powerplant enclosure clearance	Ten (10) ft horizontal clearance all around. Eight (8) ft vertical clearance
Sewer	To be determined
Telecommunications	Two lines required for prototype

Table 2. Preliminary fuel cell siting criteria.

1. Steady-state electrical loads in excess of 1 MW
2. Easy access to existing electrical switchgear for connection of fuel cell to grid
3. Nearby access to natural gas supply ideally at 40 psig. or above
4. Nearby access to potable water supply
5. Availability of approximately 6,240 square feet of space for installation, plus an additional 500 square feet for maintenance
6. Steady-state thermal loads for heat recovery in excess of 1,200,000 Btu/hr
7. Nearby access to telecommunication
8. Nearby access to sanitary sewer
9. Approval of site by RIA

Phase II

Historical electrical and thermal loads data were obtained from RIA and the utilities that serve the installation. End-use energy consumption data for selected end-uses were developed based on metered data and engineering estimates. Interactions of the fuel cell with various end-users, including the central heating plant, were developed based on fuel cell output characteristics and engineering analysis.

Phase III

Researchers developed a stochastic energy balance and cost model based on RIA historical electrical and thermal energy purchase data (Appendix A) and the siting assumptions developed in Phase II of the study. This model captured weather and seasonal driven variations in energy consumption and price along with the uncertainty exhibited in historical data. The model provides details of energy savings and calculates avoided emissions resulting from the installation of the MCFC fuel cell as forecasted probability distributions. By adjusting the energy balance relationships, different model scenarios were developed and analyzed that pivot about future possible plans for Central Heating Plant retirement.

Mode of Technology Transfer

The results of this study will be provided directly to RIA personnel, and will be made available via the world wide web through CERL's web page: www.cecer.army.mil; and the DOD Fuel Cell Demonstration website at: http://www.dodfuelcell.com.

Units of Weight and Measure

U.S. standard units of measure are used throughout this report. A table of conversion factors for Standard International (SI) units is provided below.

SI conversion factors		
1 in.	=	2.54 cm
1 ft	=	0.305 m
1 yd	=	0.9144 m
1 sq in.	=	6.452 cm^2
1 sq ft	=	0.093 m^2
1 sq yd	=	0.836 m^2
1 cu in.	=	16.39 cm^3
1 cu ft	=	0.028 m^3
1 cu yd	=	0.764 m^3
1 gal	=	3.78 L
1 lb	=	0.453 kg
1 kip	=	453 kg
1 psi	=	6.89 kPa
°F	=	(°C x 1.8) + 32

2 Phase I

Site Data

General

Several siting considerations are common to all candidate locations at Rock Island Arsenal. The following sections describe common requirements for interfacing the fuel cell to RIA systems.

Utility Connections

Both electricity and natural gas are supplied to Rock Island Arsenal by Mid American Energy Co.*

Electrical

To efficiently use the electrical output of the fuel cell, the fuel cell should be connected to the 13.8 kV electrical distribution system at RIA. This will ensure a constant loading at the capacity of the fuel cell. (The alternative—connecting the fuel cell to a 480 V RIA system—would not guarantee a constant load.)

Since the fuel cell produces direct current (DC), it will be necessary to include an inverter to convert the electricity to 480 V three-phase alternating current (AC). This inverter should be designed to minimize harmonic content of the resulting sine wave.

In addition, it will be necessary to provide transformation from 480 V three-phase to 13.8 kV. The Rock Island Arsenal uses transformers that are delta connected at 13.8 kV. The system has a ground wire, but does not have a neutral.

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* Mid American Energy Co., 2811 5th Avenue, Rock Island, IL 61201.

Harmonic and grounding issues should be studied when determining the proper connections for this transformer bank (Phase II of this study).

Electrical protective devices must be installed to protect the fuel cell from system fault currents. Also, the distribution system must be protected from the fuel cell. System synchronization and outage issues must also be addressed (Phase II of this study). System protection during short term (or momentary) outages is a concern.

The contact person at Mid American Energy for electricity issues is Tom House, Tel.: 319-333-8826.

RIA submeters many electrical loads. Monthly kWh data is available from these submeters. Maximum kW demand data for the submetered loads is not readily available in the computer database. Demands can be retrieved manually from meter reading sheets. Figure 2 shows the total installation purchased electrical usage. Minimum monthly on-peak demand is about 13 MW.

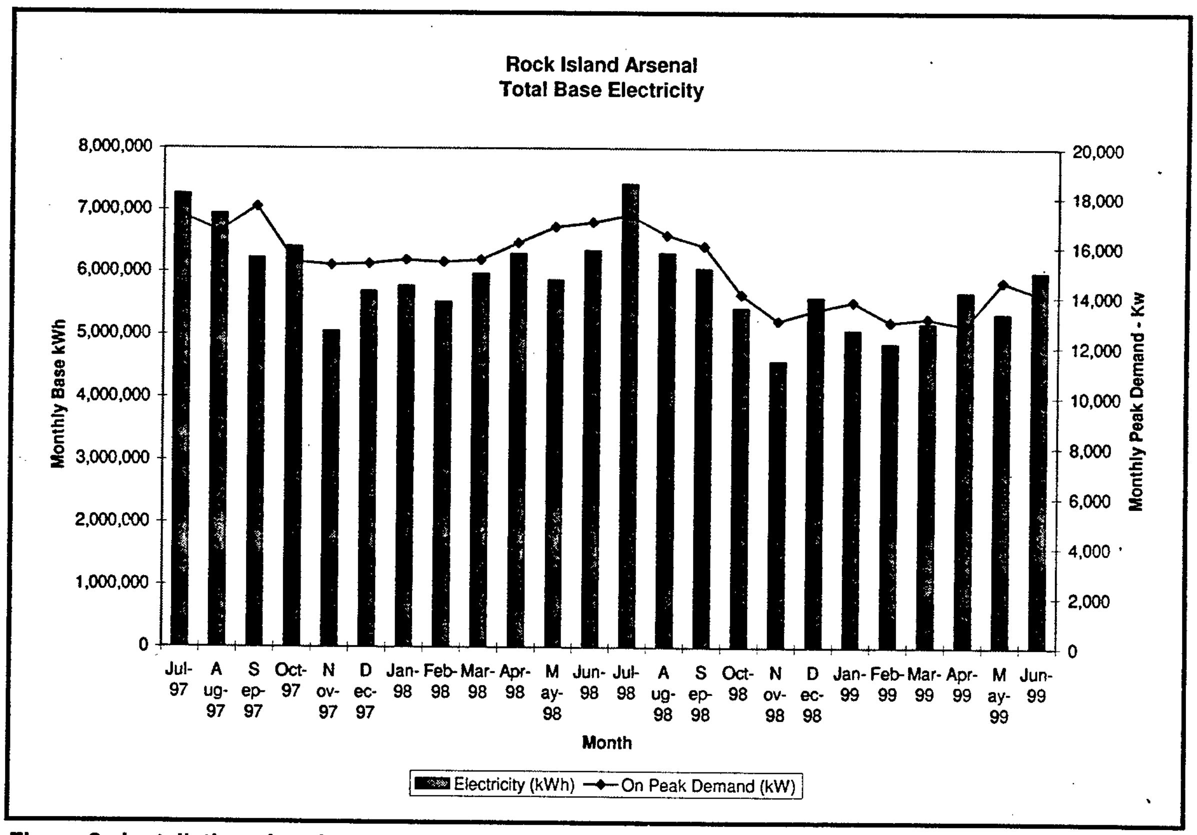


Figure 2. Installation electric energy usage.

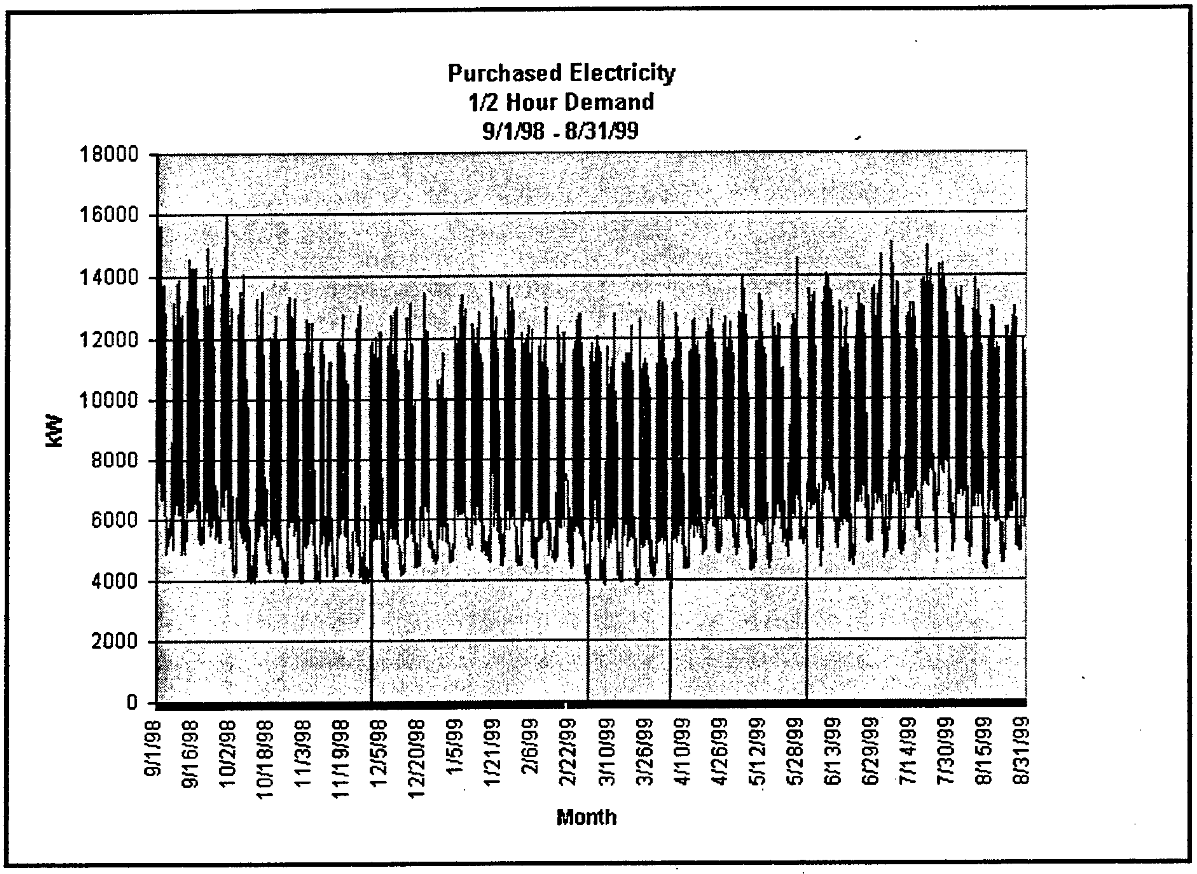


Figure 3. Purchased electricity 1/2 hour demand.

Figure 3 shows Arsenal-purchased kW at 1/2 hr intervals. During the time period shown, the maximum demand of 16 MW occurred on 30 September 1998. The minimum demand of 3.7 MW occurred on 4 April 1999 (Easter Sunday). The Arsenal operates a hydroelectric generator of 3 MW capacity. The output is dependent on river head. In September 1998 for example, the generator capacity was 1.6 MW. Even if the hydroelectric plant operated at full capacity, 700 kW of load would remain for the fuel cell.

Natural Gas

The natural gas system at RIA operates at a pressure of 30 psi. The fuel cell requires a minimum pressure of 105 psi. It will be necessary to install a gas compressor as part of the fuel cell installation to boost the pressure of gas supplied to the fuel cell. The impact of this compressor on noise levels should also be studied (Phase II of this project).

The local utility (Mid American Energy) uses mercaptan to odorize the natural gas used at RIA. Attached to this report is a specification for this odorant. Mr.

Paul Hayles (319-333-0126) may be contacted for more information. Mr. Hayles confirms that Mid American does not use propane-air for peak shaving.

Water

It will be necessary to install a water line to any of the candidate sites. This requirement should be met at any of the sites without major expense.

Sewer

The need for a sanitary sewer line at the fuel cell site needs to be determined.

Telecommunication

The fuel cell prototype will require a telecommunication connection.

Foundations

Bedrock depth varies at the candidate sites, but it is generally within 5 ft of the surface. None of the sites should present any unusual excavation problems with the possible exception of bedrock. All are located in "disturbed areas" and their historical preservation is not a concern of RIA.

Site 1 – Building 350

Building Description

Building 350 is a large administration building. The building is a six-story concrete/masonry unit structure with an area of 440,000 sq ft. Building population is approximately 1500 persons. Two of the six floors support 24-hour-a-day computer missions. The remainder of the building operates as day shift administrative space. The two floors of the building that house computer mission require high reliability electrical power. Diesel generators of 1 MW capacity are currently being installed adjacent to the building to provide back-up electric service.

Electrical Service

Electricity to Building 350 is supplied through several circuits. Four electrical meters measure the electrical usage to the building (Figure 4). Usage peaks during the summer months, and varies between a minimum of about 400,000 kWh and a maximum of 1,300,000 kWh per month. Maximum non-coincident demand was 1,333 kW in January 1998 and 1,309 kW in August 1998.

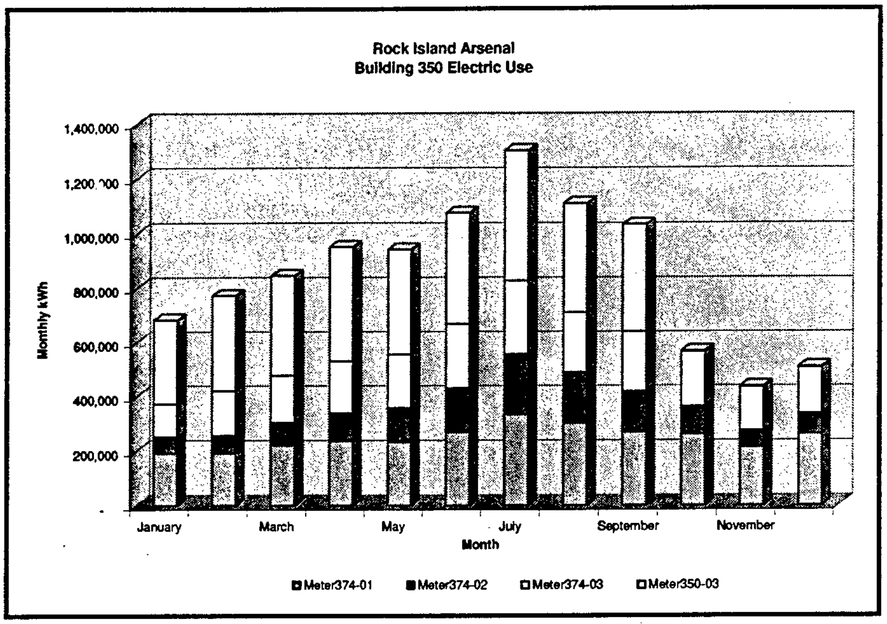


Figure 4. Building 350 electricity usage.

Natural Gas Service

There is presently no natural gas service to Building 350.

Heating Energy Consumption

Building 350 is heated entirely by the central steam plant. Steam is supplied at 130 psig. Estimated average hourly steam consumption for heating during the peak heating month (January) is approximately 12,000 lb/hr (Sliwinski et al. February 1979). Table 3 lists the estimated average hourly steam consumption by month.

Table 3. Building 350 estimated steam consumption for heating.

Month	HDD	Estimated avg. steam lb/hour
Jan	1,400	11,979
Feb	1,135	10,853
Mar	856	7,707
Apr	450	4,636
May	178	2,382
Sept	108	1,861
Oct	389	4,039
Nov	764	7,184
Dec	1,227	10,620

Cooling Energy Consumption

The building is served by a Trane Model ABTD-07A 750 ton, two-stage, steam-driven absorption chiller located in Building 348. The chiller was installed in 1976. Steam is supplied to the chiller at 123 psig. Hourly steam consumption is approximately 12.2 lb/hr/ton. The chiller serves both Building 350 and Building 390. Installation personnel estimated that the chiller provides approximately 450 tons of cooling to Building 350. Additional cooling is supplied to Building 350 by two smaller single-stage steam-driven chillers located on the first and sixth floors of the building. The first floor chiller has a rated capacity of 174 tons but currently provides only 150 tons of cooling. The 6th floor chiller has a capacity of 150 tons. Both chillers use steam at 12 psig. Hourly steam consumption for these smaller chillers is approximately 18.7 lb/hr/ton. All chillers are expected to remain in place for the next 3 to 5 years.

Both of the smaller chillers operate 24 hours a day, 7 days a week during the cooling season. The 750 ton chiller is shut down on weekends.

Fuel Cell Site Considerations

Physical Location

Two locations adjacent to Building 350 were examined for placement of the fuel cell. The first is a loading and utility area on the east side of Building 350 (Figures 5 and 6). A new 13.8 kV substation (Substation H) is currently being constructed in this area and will serve Building 350. Space at this site is limited and placement of the fuel cell facility may be difficult. The fuel cell can be installed about 4 ft west of an existing buried electrical duct and south of the new substation. This site will require arranging the fuel cell units to form a 120 ft long by 52 ft wide footprint. This will allow about a 10-ft clearance between Building 350 and the facility. Overall, the site is cramped; there could be unforeseen difficulties in access for construction and maintenance. Before final selection of this site, it will be necessary to verify the as-built location of the new substation. If this site is chosen, the fuel cell can be connected into a spare 13.8 kV terminal in a pad-mounted switching center (S68 or S71) adjacent to the new substation.

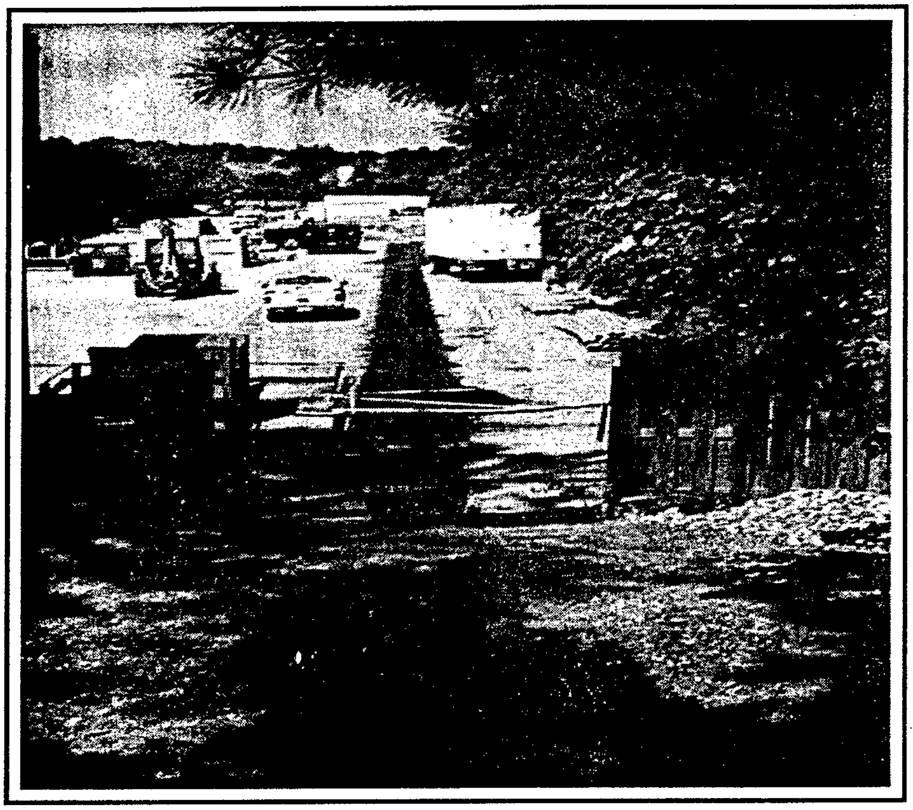


Figure 5. Potential fuel cell site in loading area east of Building 350, looking north.

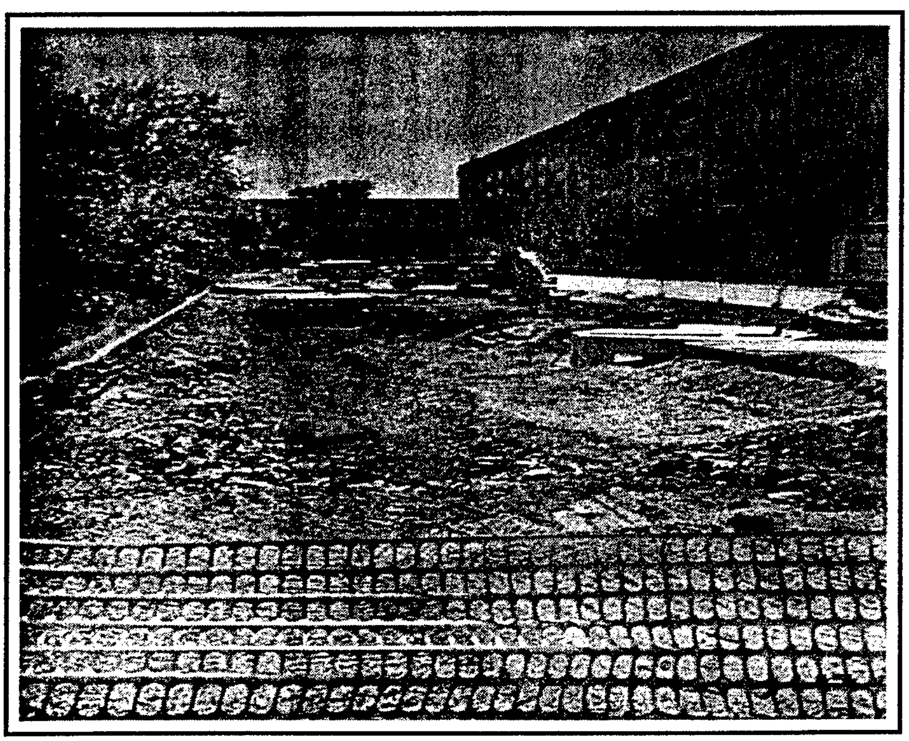


Figure 6. Same area looking south, Building 350 on the right.

An alternate location exists in the park area east of the loading area (Figure 7). The new 13.8 kV substation is replacing a 2.4 kV substation (old Substation H) in the park. It would be possible to site the fuel cell in the same approximate area of the old substation. This substation is scheduled for removal in 2001. Electrical connection could be made in the existing pad-mounted switch compartment (S67) that will remain adjacent to the old substation location.

The major disadvantages of the park location are appearance and a longer distance to pipe steam to Building 350. The Arsenal may require landscaping around the fuel cell if the unit is located in this area.

Electrical Connections

The fuel cell can be connected to the 13.8 kV system in pad-mounted switchgear adjacent to either proposed site, as described above. It will be necessary to install suitable electrical ducts between the fuel cell and the selected switching device. No major expense is anticipated.

Natural Gas Connections

Presently, there is no natural gas service in the vicinity of Building 350. It will be necessary to install a 2-in. gas line from near the Steam Plant to the site of the fuel cell. This is an extension of about 1900 ft. Directional boring should minimize disruption to the historical area.

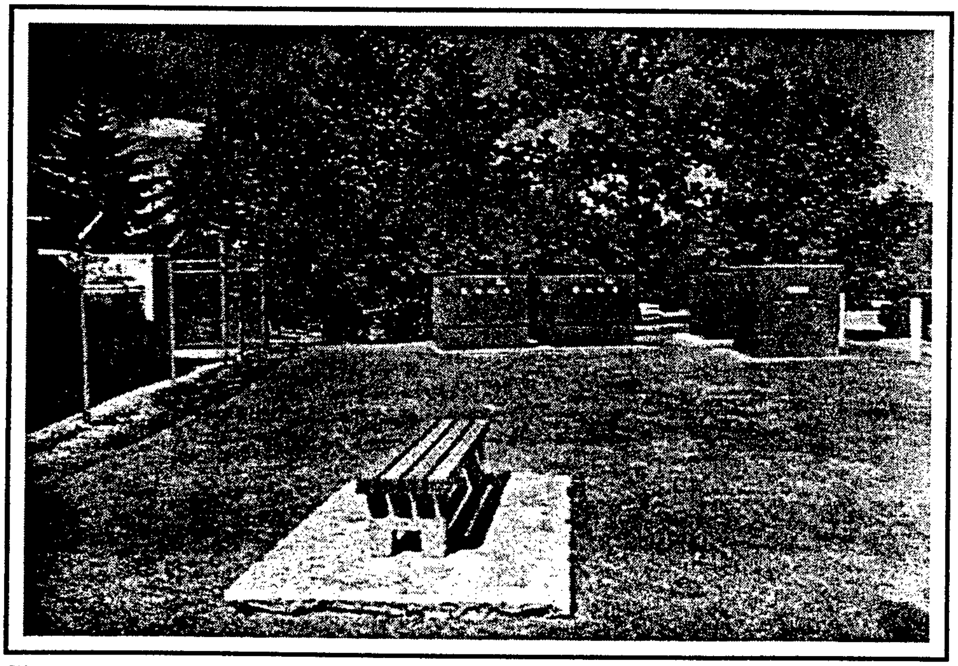


Figure 7. Alternative site in park area with old Substation H on left and switches.

The extension of natural gas service to Building 350 will necessitate crossing an underground steam tunnel. This tunnel occupies a space extending from 1 ft below grade down to bedrock. Coordination with RIA personnel will be required to determine the best method to cross this tunnel.

Potable Water

Potable water is available at the site.

Heat Recovery Options

The site provides good opportunities for heat recovery from the fuel cell. Steam from the cell can be used to supplement the building heating during the heating season. Average steam demand for heating should allow full usage of the fuel cell thermal output. During the cooling season, steam from the fuel cell can be used to drive the smaller single-stage absorption chillers. These chillers operate continuously during the cooling season. They will be capable of using the full fuel cell thermal output down to about 20 percent of their cooling load.

Site 2 - Central Steam Plant

Building Description

The central steam plant is located in Building 227. The steam plant is centrally located in the main manufacturing and administrative complex and operates year round to provide steam for heating, cooling, and process needs. Total coal-fired steam capacity is 410,000 lb/hr at 135 psig. Average hourly steam production during the heating season is about 100,000 lb/hr. During the cooling season, hourly steam production averages 30,000 lb/hr for cooling and process requirements. The plant has four coal-fired boilers having capacities of 100,000, 100,000, 130,000, and 80,000 lb/hr.

Electrical Service

Electricity is supplied to the Steam Plant through three distribution circuits, and each is submetered. Electrical usage peaks during the winter months and depends on the number of boilers in operation. Usage varies between a minimum of about 300,000 kWh and a maximum of 1,200,000 kWh (Figure 8). Maximum non-coincident demand was 1267 kW in January 1998 and 816 kW in August 1998.

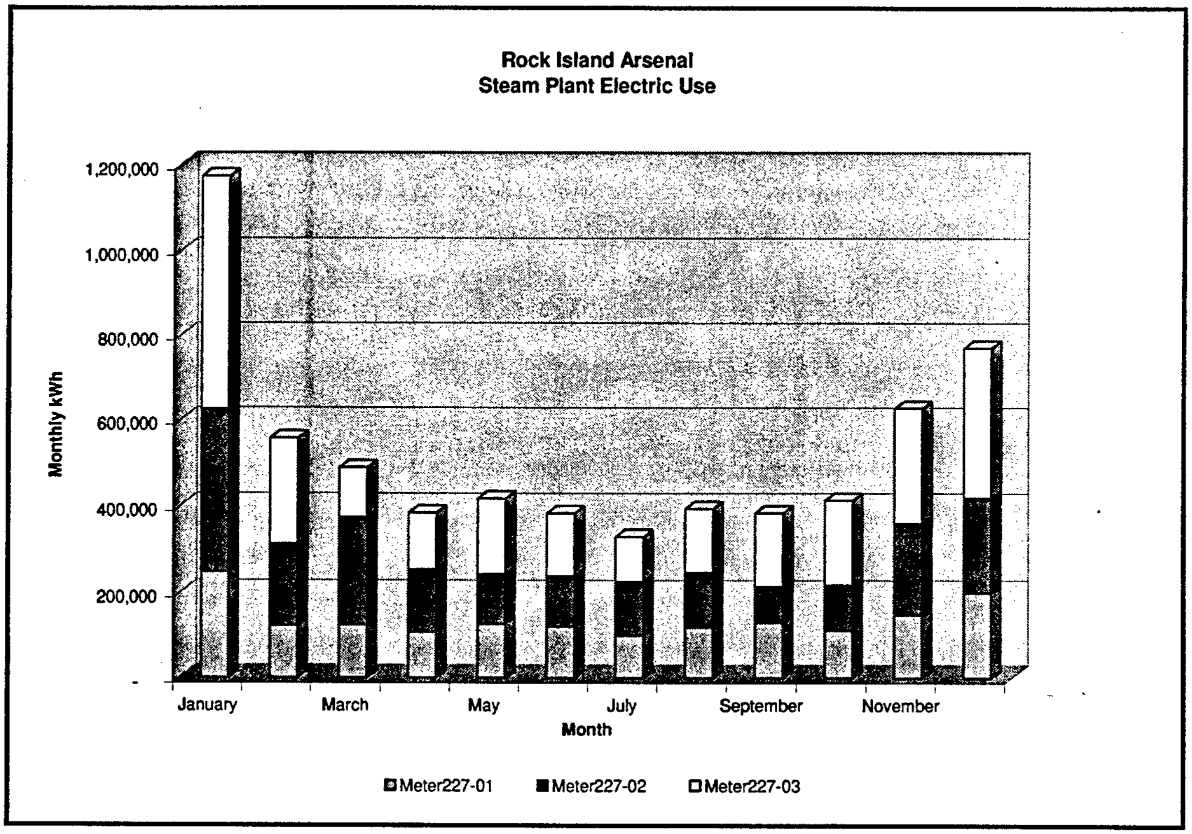


Figure 8. Steam plant electricity usage.

Natural Gas Service

There is natural gas service at 30 psig adjacent to Building 227.

Fuel Cell Site Considerations

Physical Location

The parking and coal delivery area on the south side of Building 227 is the most desirable site for the fuel cell (Figures 9 and 10). An existing 13.8 kV substation (Substation G) is located at the west end of the steam plant building. The fuel cell can be installed along the north edge of the parking area and south of the substation. Coal is delivered to the steam plant by truck, and clearances for these deliveries must be maintained. The fuel cell can be connected into a spare 13.8 kV terminal in a pad-mounted switching center (S52 or S53) adjacent to the substation.

There are several apparently dormant railroad tracks in the area. Phase II must determine their future. Several sewer and gas lines also traverse the area, and the fuel cell siting must not conflict with these.

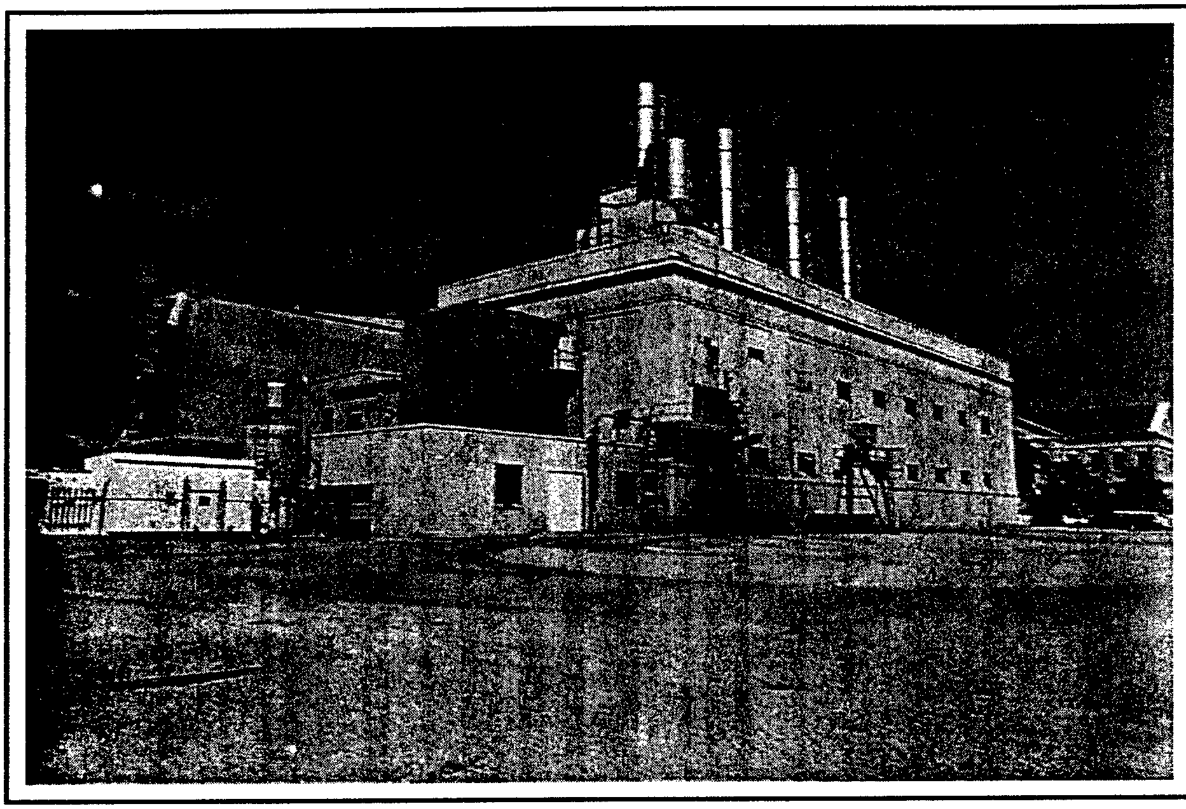


Figure 9. Steam Plant viewed from approximate site of fuel cell, substation and switches on left.

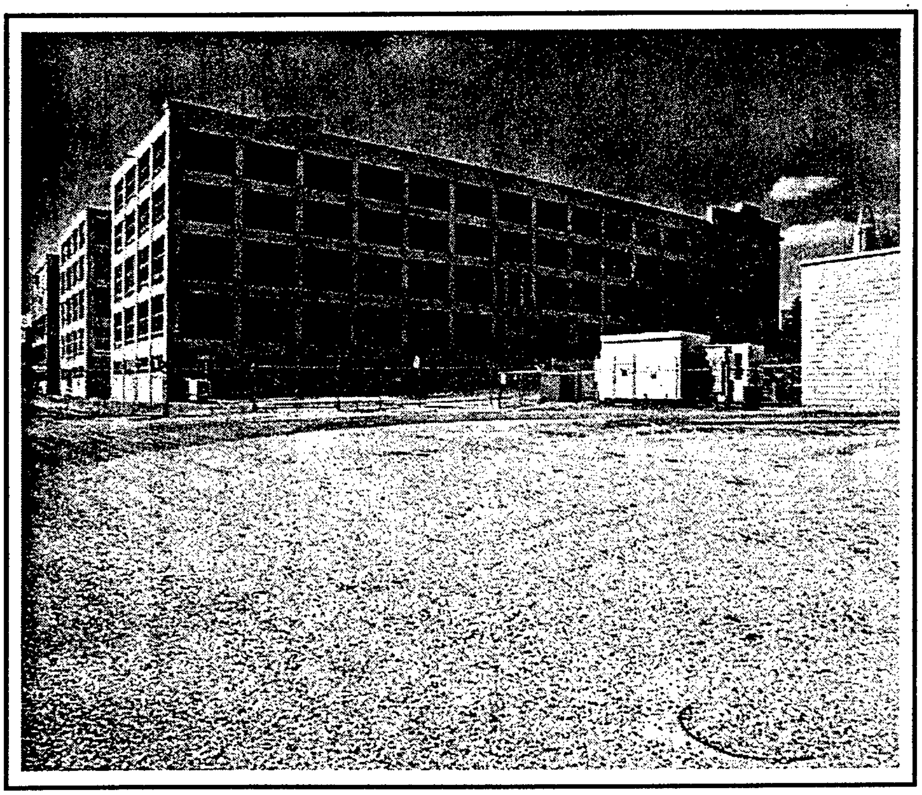


Figure 10. Another view from the fuel cell site looking NW, substation on right.

Electrical Connections

The fuel cell can be connected to the 13.8 kV system in pad-mounted switchgear adjacent to the steam plant substation, as described above. It will be necessary to install suitable ducts between the fuel cell and the selected switching device. No major expense is anticipated.

Natural Gas Connections

A 4-in. natural gas line is adjacent to the site. Gas pressure is 30 psig. Service to the fuel cell should be available at minimum cost.

Potable Water

Potable water is available at the site.

Heat Recovery Options

Heat recovery options are good at this site. Minimum steam production by the central plant is 30,000 lb/hr—far in excess of the fuel cell thermal output. It is likely that the full thermal output of the fuel cell could be recovered either to make steam or to preheat boiler feedwater.

Site 3 - Building 212 Plating Operations

Building Description

Building 212 is a modern manufacturing facility with an area of approximately 315,000 sq ft. The building contains equipment for a variety of heavy metal fabrication processes including electroplating. Railroad tracks separate the building from areas where the fuel cell could be sited. Underground piping would need to be constructed. The usage level of the facility appeared low at the time of the site inspections.

Electrical Service

Electricity to Building 212 is supplied through several distribution circuits. Four electrical meters measure the electrical usage to this portion of the building. Electrical usage is relatively constant throughout the year, and varies between a minimum of about 400,000 kWh and a maximum of 600,000 kWh. Maximum non-coincident demand was 1,070 kW in January 1998 and was 1,100 kW in August 1998.

These electrical loads are based on a substation located near the plating area (transformers T25, T26, T30, and T31). These loads represent only a fraction of the total electrical use of Building 212. Also, the activity in this building was minimal at the time of this study. If full production occurs, the electrical usage would increase dramatically.

Natural Gas Service

There is natural gas service at 30 psig adjacent to Building 212.

Fuel Cell Site Considerations

Physical Location

A parking area on the south side of Building 212 is the most desirable site for the fuel cell (Figure 11). The fuel cell can be connected at a spare 13.8 kV terminal in a pad-mounted switching center adjacent to the parking area (S20 or S35). The fuel cell can be installed along the north edge of the parking area. It will be necessary to remove some parking spaces and relocate a section of fence.

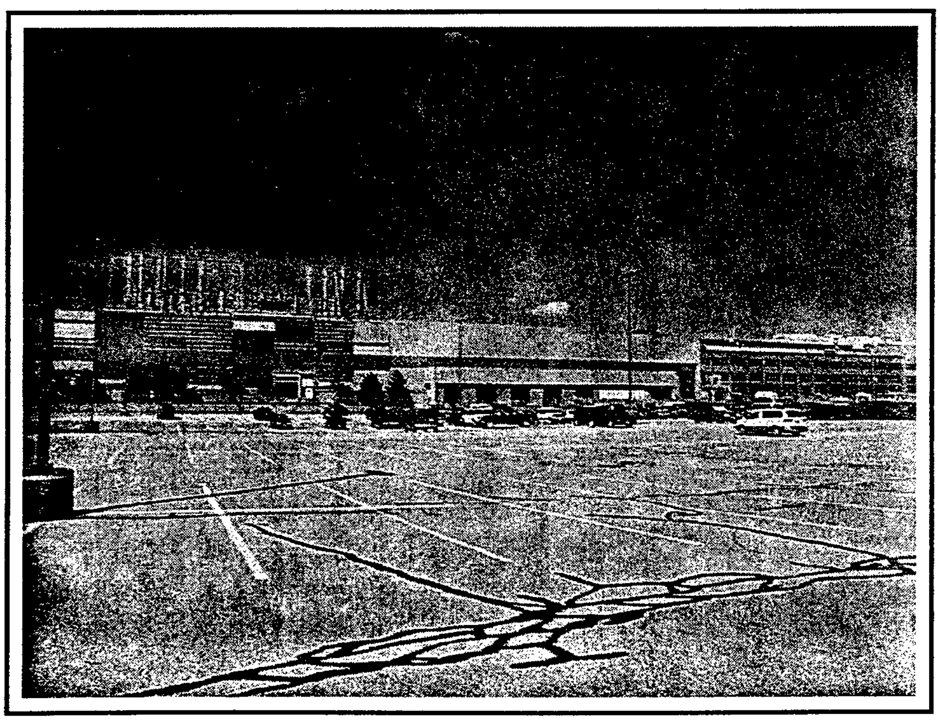


Figure 11. Building 212 from south, looking across parking lot where fuel cell may be sited.

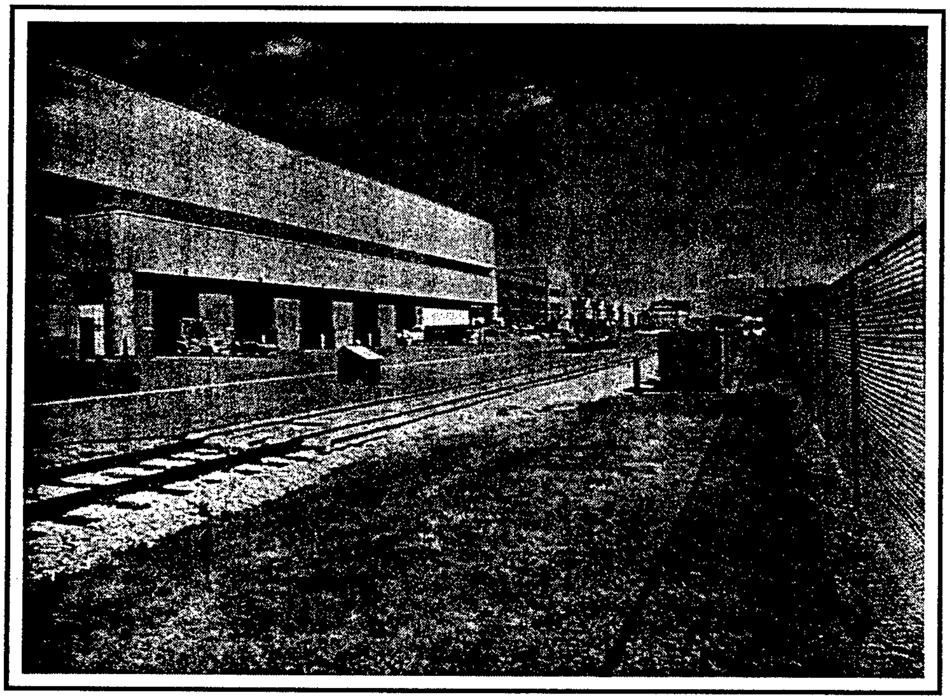


Figure 12. Building 212 looking across railroad tracks and loading area separating building from fuel cell site, switches on right.

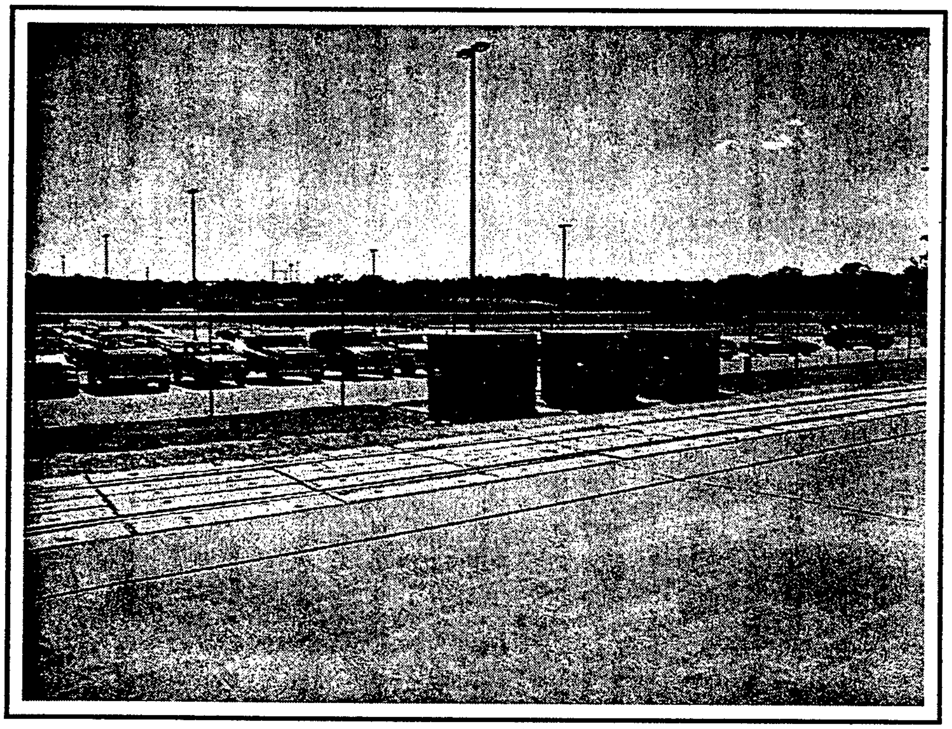


Figure 13. View of switches from Building 212 looking from the north toward fuel cell site.

The disadvantage of the parking lot location is the necessity of crossing beneath a railroad track (Figures 12 and 13) and a wide concrete driveway with the steam line and a water supply line.

Electrical Connections

The fuel cell can be connected to the 13.8 kV system in pad-mounted switchgear adjacent to the proposed site, as described above. It will be necessary to install suitable ducts between the fuel cell and the selected switching device. No major expense is anticipated.

Natural Gas Connections

A 4-in. natural gas line exists near the fuel cell site. Gas pressure is 30 psig. No major connection expense is anticipated.

Potable Water

Potable water is available at the site.

Heat Recovery Options

Heat recovery options have not been completely determined at this time. Heat may be recovered for plating baths. However, the facility is presently used intermittently and probably only a limited amount of fuel cell waste heat can be used. Further information needs to be gathered to determine future plans and usage levels.

Site 4 - Research and Development Area

Building Description

This area is remotely located at the east end of Rock Island Arsenal. There are six buildings within the complex—Buildings 23, 25, 32, 34, 38, and 46. The largest building is Building 25 with an area of 48,262 sq ft.

Electrical Service

A 13.8 kV overhead line serves the site. Several transformer banks at the site reduce the voltage for use within the complex. All transformers are either pole-mounted or mounted on raised platforms. Apparently site flooding is a concern.

Natural Gas Service

Natural gas service is available at the site. Gas pressure at the site is 80 psig.

Heating Energy Consumption

Heating for Building 25 is provided by an oil-fired boiler. The other buildings in the complex are served by a boiler located in Building 38. The capacity of this boiler is 1,041,000 Btu/hr. The boiler provides steam at 12 psig. The boiler is operated only during the summer months.

Fuel Cell Site Considerations

Physical Location

There does not appear to be a convenient location for the fuel cell site. A cleared central area in which transformers are mounted may be prone to flooding (based on the observation that the transformers are mounted on a raised platform). A wooded area to the west of Building 25 may be suitable, but clearing and grading would be required.

Electrical Connections

The 13.8 kV overhead line at the site can be used to connect the fuel cell to the grid. A 480 V/13.8 kV transformer bank and pad-mounted switching compartment will be required. The pad-mounted equipment may need to be elevated to protect from possible flooding. If the 13.8 kV line is out of service, the fuel cell could supply power to the R&D complex. However, it appears that there is not sufficient local load to fully use the output of the fuel cell under these circumstances. Sectionalizing devices would be required to isolate the R&D area from the grid, reconnect the fuel cell, and then re-synchronize with the system when grid power is restored.

Natural Gas Connections

Natural gas is available at the site at 80 psig.

Potable Water

Potable water is available at the site.

Heat Recovery Options

Heat recovery options at this site are limited. The main boiler at the site operates seasonally to supply heating. The full load of the boiler is less than the fuel cell heat recovery output.

Summary

Table 4 lists the ranked site criteria.

Table 4. Fuel cell siting criteria.

Criteria	Site 1 Building 350	Site 2 Central Plant	Site 3 Building 212 (Plating)	Site 4 R&D Area
1. Steady-state electrical loads in excess of 1 MW.	Good (Grid)	Good (Grid)	Good (Grid)	Good (Grid)
2. Easy access to existing electrical switchgear for connection of fuel cell to grid.	Good	Good	Good	Fair
3. Nearby access to natural gas supply ideally at 40 psig. or above.	Fair	Good	Good	Fair
4. Nearby access to potable water supply.	Good	Good	Good	Good
5. Availability of approximately 6,240 square feet of space for installation, plus an additional 500 square feet for maintenance.	Poor	Good	Good	Fair
6. Steady-state thermal loads for heat recovery in excess of 1,200,000 Btus/hr.	Good	Good	Fair	Poor
7. Nearby access to telecommunications.	Good	Good	Good	Good
8. Nearby access to sanitary sewer.	Good	Good	Good	Good
9. Approval of site by RIA.				
Average Rating (Good = 3, Fair = 2, Poor = 1)	2.6	3	2.9	2.4

Environmental and Energy Impacts

Air Emissions Impacts

Installation of a 1 MW fuel cell at Rock Island can result in reduced emissions of SO_2, NOx, and CO_2. Emissions may be reduced at regional power plants due to the reduction in electrical load and at the base steam plant due to heat recovery from the fuel cell. Table 5 lists emission rates used to estimate annual reductions in pollutant emissions. Table 6 lists the estimated annual reductions in pollutant emissions by regional coal-fired power plants, assuming the fuel cell operates at full output for 7008 hr/yr (80 percent availability).

Further reductions in pollution emissions are possible if heat from the fuel cell is recovered for use at the Arsenal. Recovered heat will result in a reduction in load on the central steam plant. Based on data from Rock Island Arsenal, the average steam plant efficiency is 73 percent. Table 7 lists the estimated emissions reductions due to fuel cell heat recovery.

Table 5. Air pollution emission rates.

Technology	SO_2 (lb/mmBtu)	NO_x (lb/mmBtu)	CO_2 (lb/mmBtu)
Coal Combustion*	1.24	0.568	206
Molten Carbonate Fuel Cell	0	0.012	97.5
*USEPA, 1996			

Table 6. Power generation emissions reductions.

Technology	Heat Input/MWe (mmBtu/hr)	Annual Heat Input (mmBtu/yr)	SO_2 (lb/yr	NO_x (lb/yr)	CO_2' (lb/yr)
Coal Combustion	10.342	72,480	89,875	41,169	14,930,880
Molten Carbonate Fuel Cell	6.563	45,997	0	552	4,484,708
Power Generation Emissions Reduction			89,875	40,617	10,446,172

Table 7. Emission reductions due to heat recovery.

Annual Fuel Cell Heat Recovered (mmBtu/yr)	Central Plant Heat Input Reduction (mmBtu/yr)	SO_2 Reduction (lb/yr	NO_x Reduction (lb/yr)	CO_2 Reduction (lb/yr)
8,276	11,336	14,058	6,440	2,335,419

The total estimated air pollution emission reductions that may accrue due to application of the fuel cell are the sum of the power generation and heat recovery reductions:

- reduction in SO_2 emissions of 104,000 lb/yr
- reduction in NO_x emissions of 47,000 lb/yr
- reduction in CO_2 emissions of 12,782,000 lb/yr.

Energy Impacts

General

Operation of the fuel cell at full output will result in an electrical demand reduction of 1 MW. Purchased electric energy consumption will be reduced by approximately 7,008,000 kWh/yr.

Coal usage at the central steam plant may be reduced by 439 tons/yr assuming full recovery of fuel cell heat and a coal heating value of approximately 12,900 Btu/lb (Eastern Kentucky coal).

Natural gas consumption will increase by approximately 460,000 therms.

Rate Summaries

Electricity is provided by Mid American Energy Company under Rate 53, Commercial and Industrial Electric Service (Table 8).

Natural gas is supplied to the installation by Enron Gas Service. For recent billing periods, summer gas costs have averaged $0.371/therm and winter costs have averaged $0.350/therm. The costs appear to be influenced by long term as well a seasonal trends.

Approximate Cost Savings

Table 9 lists fuel cell operating costs (excluding maintenance).

The cost per MWH including demand charges for the Arsenal's purchased electricity is approximately $46.42 in summer and $36.62 in winter.

The Arsenal generates steam using coal. Steam costs are about $2.5/1000 lb of steam.

Table 10 lists an hourly savings estimate assuming all the steam and electricity produced by the fuel cell can be used.

Assuming 7008 hours operation annually, the fuel cell could save the installation about $136,000 per year.

Table 8. Summary of MidAmerican Energy Company Rate 53.

Billing Demand	Summer	Winter
All kW	$9.14/kW	$4.98/kW
On-Peak Energy	$ 0.03196/kWh	$ 0.03196/kWh
Off-Peak Energy	$ 0.02036/kWh	$ 0.02036/kWh
Basic Service Charge	$477/month	
Summer	June through September	
Winter	October through May	
On-Peak Hours	8:00 a.m. to 8:00 p.m. Monday through Friday, excluding holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.	
Minimum Charge	The minimum monthly bill shall be the basic service charge, applicable energy charges for the month, and billing demand charges for the month. No minimum monthly charge shall be less than a demand charge applicable for a billing demand of 10,000 kilowatts.	

Table 9. Fuel cell costs per MWH.

Summer MWH	65.63 therms/hr	x $.371/therm	= $24.34/MWH
Winter MWH	65.63 therms/hr	x $.350/therm	= $22.97/MWH

Table 10. Estimated hourly savings from fuel cell operation.

Season	Purchased Elec. ($/MWH)	Fuel Cell Elec. ($/MWH)	Fuel Cell Steam (lb/hr)	Value of Fuel Cell Steam ($/1000 lb)	Hourly Savings ($/hr)
Summer	46.42	24.34	1,180	2.5	25.03
Winter	36.62	22.97	1,180	2.5	16.60

3 Phase II

Description of Proposed Fuel Cell Site

Site Location

The proposed MCFC site is located south of the RIA central steam plant. It will be located near the west end of the steam plant and will be adjacent to the west line of Flagler Avenue. The north line of the fuel cell site should be at least 75 ft south of the steam plant building.

The area immediately south of the steam plant is used for several major utility lines. It also serves as a coal truck unloading area for the steam plant, and contains several apparently abandoned rail lines. Utility lines traversing this area include a sanitary sewer as well as electrical and natural gas lines.

The fuel cell fenced area should be located south of the above service and utility corridor to ensure future access to these facilities. The proposed site is in the northwest corner of a parking area. A detailed site study should be performed before preparation of civil engineering drawings necessary for construction.

The site study will identify the areas to be used during construction such as roads, storage, and other contractor operations. Availability of utility services will be determined and interfaces or taps established. Temporary routing for electricity, water, sewage, gas, etc., will be shown on the site master plan.

A foundation investigation and soils analyses report will be prepared. A report of findings will include a description of the geology of the site, a description and evaluation of site conditions pertinent to foundation design, an evaluation of foundation support capability, estimates of allowable bearing capacity and settlement predictions for imposed loads.

Figure 14 shows a preliminary layout for the proposed 1 MW Molten Carbonate Fuel Cell Generator and its relationship to existing steam plant Building 227. There is approximately 75 ft of space between the steam plant building and the proposed site for the MCFC generator. The area contains abandoned railroad tracks, a sewer line, and natural gas and electric lines.

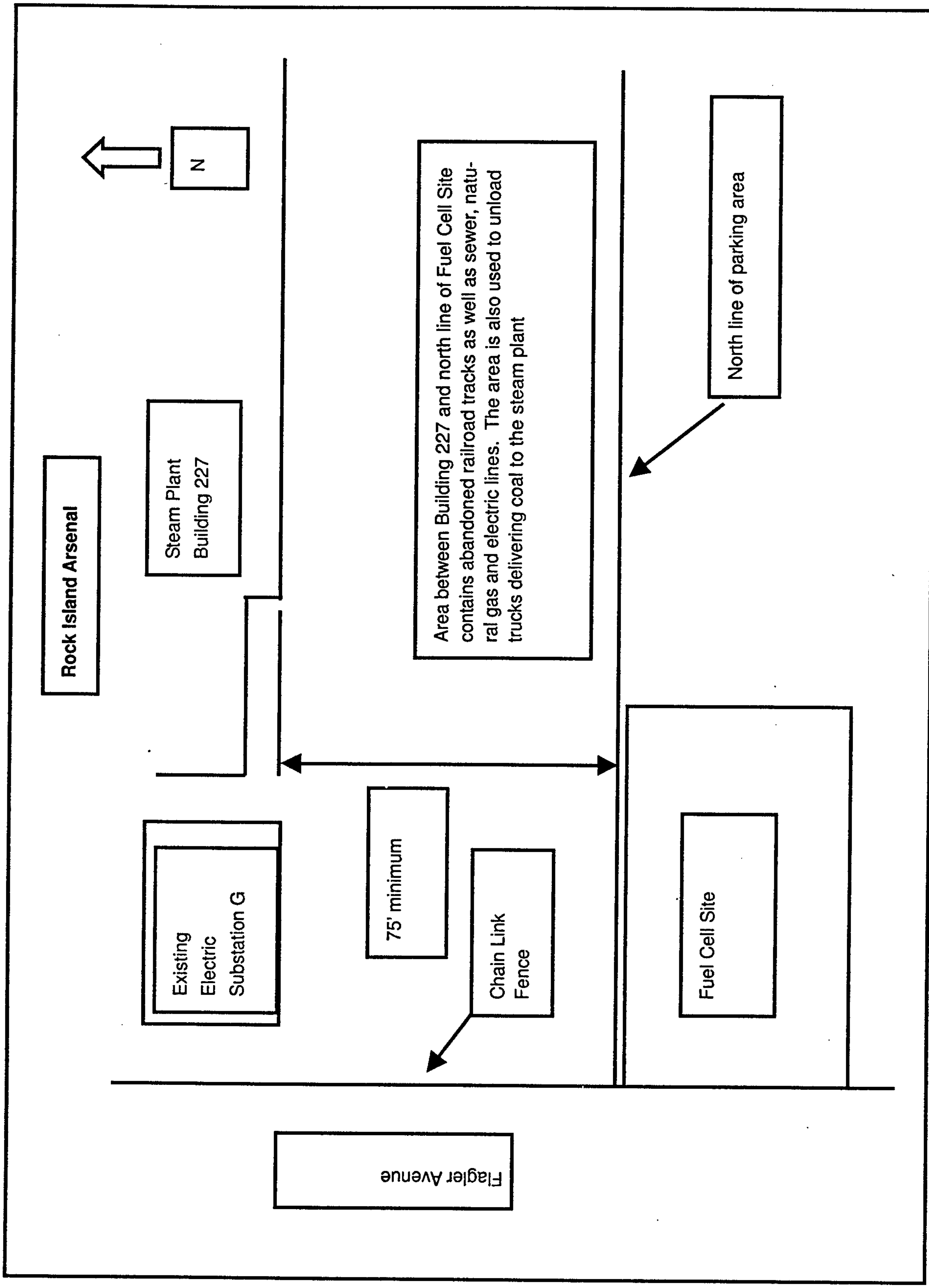


Figure 14. Proposed site plan for 1 MW molten carbonate fuel cell generator.

Figure 15 shows a preliminary general arrangement for the proposed 1 MW MCFC generator. For security and safety purposes, the generator and ancillary equipment would be enclosed with a chain link fence. There is adequate space for an equipment laydown area to accommodate fuel cell installation needs, stack replacement, and general maintenance.

Utilities Interface

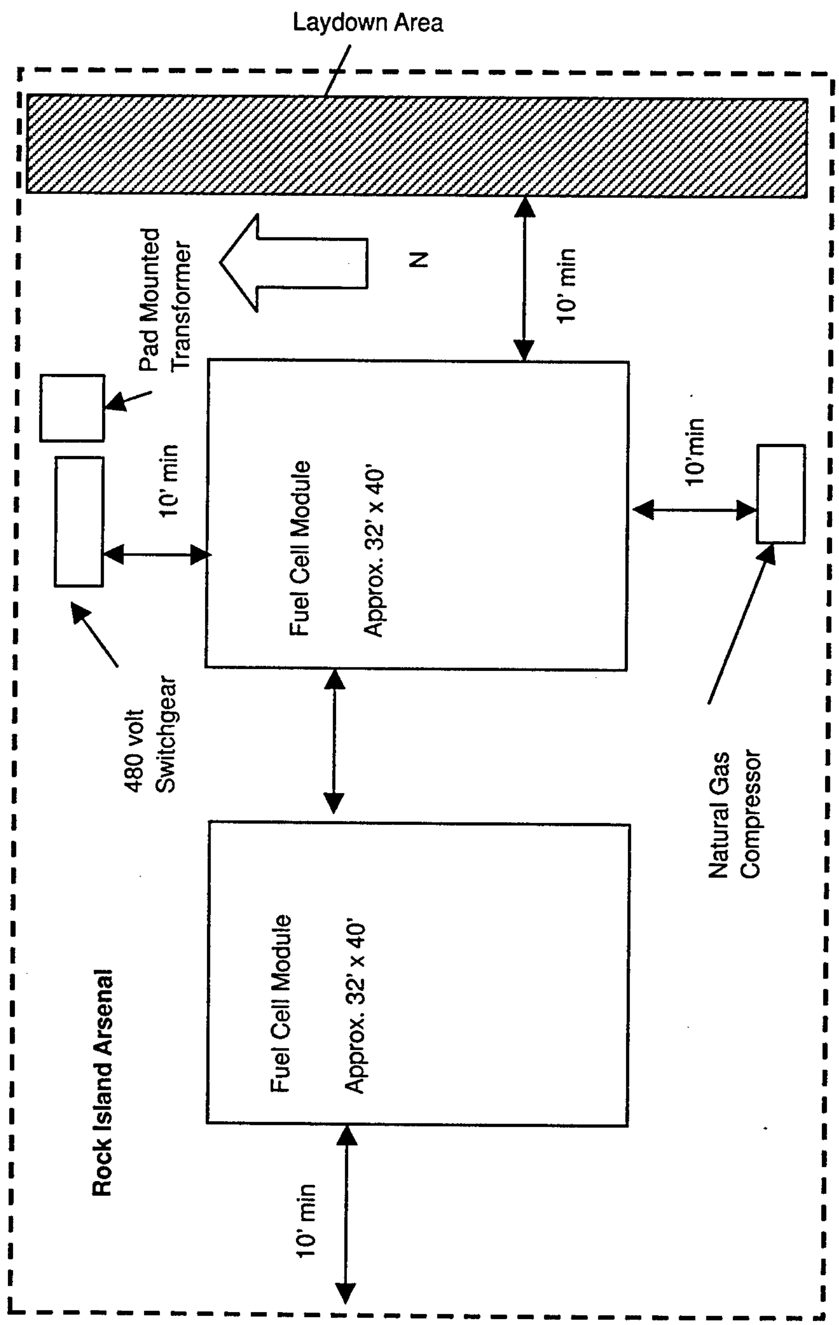
MidAmerican Energy Co. supplies both electricity and natural gas to RIA. Mr. House and system protection personnel from MidAmerican have verified that the fuel cell poses no system safety problems for MidAmerican Energy. They indicate that their main arsenal substation is equipped with sufficient electric protection equipment to prevent backfeed from the Arsenal's hydro-electric plant, and therefore the fuel cell output should not present any backfeed concerns.

At present, a trip signal is sent to the circuit breakers of the hydro plant anytime there is a transmission line outage to the Arsenal. This prevents any backfeed during a high voltage outage on MidAmerican's system. During the design phase study of a fuel cell installation, it should be determined if a trip signal should be sent to the fuel cell circuit breaker under the same conditions.

Natural Gas

The natural gas system at Rock Island Arsenal operates at a pressure of 30 psig. An existing 4-in. natural gas main is located in the utility corridor south of the steam plant. This line has sufficient capacity and can be tapped with a gas service extended to the south side of the fuel cell site. This extension should be about 150 ft in length.

The fuel cell requires a minimum pressure of 105 psig. A natural gas compressor and possibly a redundant spare would be provided to supply compressed natural gas to the fuel cell at a constant pressure at all operating conditions. The compressor would be a nonlubricated piston-type operating at constant speed. A natural gas cooler would be included in the kickback loop to prevent a temperature buildup at the compressor inlet during part load conditions. A pulsation dampening vessel would be used to dampen pressure fluctuations in the compressor discharge line. The compressor station will most likely be located adjacent to the south line of the fuel cell site, but within the fenced area.



Additional Information:

Site to be enclosed with chain link fence

Gates positioned as necessary to maintain equipment

Laydown area will be used during installation and maintenance activities

Space requirements for natural gas compressor, electric switchgear, and transformer to be determined

Drawing not to scale

Figure 15. Proposed molten carbonate fuel cell installation.

The local utility, MidAmerican Energy, uses mercaptan to odorize the natural gas used at RIA. Appendix B contains a specification for the gas odorant used at RIA. A zinc oxide sulfur removal system can readily reduce the sulfur content to less than 0.1 ppm. Mr. Paul Hayles confirms that MidAmerican does not use propane-air for natural gas peak shaving.

Water

It will be necessary to install a water line to the fuel cell site from the steam plant. This requirement should be met at any of the sites without major expense. No water lines exist in the utility corridor south of the steam plant. However, there are water mains just east and west of the central heating plant.

Sanitary Sewer

A sanitary sewer line exists within the utility corridor south of the steam plant. This line can be extended to the fuel cell site.

Storm Sewer

A storm sewer terminates on the west side of Flagler Avenue just south of Substation G.

Telecommunication

The fuel cell site will require a telecommunication connection, which can be readily extended from the existing steam plant.

Foundations

Bedrock depth varies at the candidate site, but it is generally within 5 ft of the surface. The existence of bedrock should be determined during the foundation investigation and soil analysis work described above. The proposed fuel cell location is within a "disturbed area" and historical preservation is not a concern of the RIA. The environmental investigation and assessment report will address this issue.

Electric and Thermal Configuration

Electrical

This study recommends that the fuel cell be connected to the 13.8 kV electrical distribution system at Substation G. This substation is located adjacent to the west end of the steam plant. The output of the fuel cell inverter is 480 V, three phase. Connection at 13.8 kV will require the installation of a 1000 kVA pad-mounted transformer within the fuel cell fenced area. The initial expense of this transformer is offset by the following considerations:

- The fuel cell can be connected into a spare 13.8 kV terminal in a pad-mounted switching center (S52 or S53) within Substation G. It will only be necessary to extend one 13.8 kV circuit from the fuel cell transformer to Substation G. No disruption of service will be required since the Substation G switchgear can be electrically isolated without any interruption of service to the central steam plant.
- The harmonics generated by the fuel cell inverter, although better than typical power line harmonics, would most affect other loads connected to the 480 V bus. If the connection to the Arsenal electric system is made at the 480 V level at Substation G, it could expose sensitive electronics at the central steam plant to these harmonics. Even though the fuel cell will be designed to comply with the harmonic restrictions of IEEE 519, this risk can be greatly reduced by connection at the 13.8 kV level.
- The central steam plant is served from Substation G. The 480 V switchgear is throat-connected to the 13.8/0.48 kV transformers. Connection of fuel cell 480 V circuits would require expansion of the switchgear, and would likely result in a forced outage to the central steam plant. Since this is double-ended switchgear, simply extending the switchgear would not be possible.
- Connection to the RIA's electric system at 13.8 kV is the preference of the staff electrical engineer. The entire fuel cell construction can be completed without disruption to the Arsenal's electric system. When fuel cell construction is complete and the fuel cell generator is ready for energizing, switch S52 (or S53) can be used to isolate the fuel cell, and the connection can then be completed.
- Connection to the electric system at the 13.8 kV level ensures that the full output of the fuel cell can be used at all times without regard to central steam plant electric loads, Substation G transformer capacity, or the future of the central steam plant.
- By selectively opening switches in the 13.8 kV switchgear (S52 or S53), it will be possible to isolate the fuel cell and the central steam plant so the fuel cell can assist in "black" start of the steam plant.

Since the fuel cell produces DC, an inverter is always included as part of the power plant to convert the electricity to 480 V, three-phase AC. This inverter will be designed to comply with applicable provisions of IEEE Standard 519 to minimize harmonic content of the AC waveshape.

It will be necessary to provide transformation from 480 V, three phase to 13.8 kV. The Rock Island Arsenal uses transformers that are delta connected at 13.8 kV. The system has a ground wire but does not have a neutral. Harmonic and grounding issues should be studied when determining the proper connections for this transformer bank during design of the installation.

It is proposed to locate a 1000 kVA, 13.8/0.48 kV, pad-mounted transformer within the fuel cell fenced area. Suitable conduit and 15 kV cable will be extended underground to the nearest existing manhole, and the cable extended in existing ducts to Substation G. Gary Cook at Rock Island Arsenal can supply information on the location of the suitable manhole for this connection.

Electrical protective devices will be installed to protect the fuel cell from system fault currents. Also, the distribution system will be protected from the fuel cell. It is anticipated that the fuel cell will consist of two power plant modules, and each module will have its own circuit protection.

This study proposes the installation of self-standing outdoor switchgear adjacent to the pad-mounted transformer. This switchgear would contain the main 480 V bus, a main disconnect switch, and would serve as the termination point for cable connections to each fuel cell unit. Metering equipment can also be installed in the switchgear to monitor the output of the fuel cell installation. Figure 16 shows a single line drawing of the fuel cell electrical interface.

Relaying, Remote, and Local Control Issues

As part of the installation engineering design, system synchronization and outage issues will be addressed with RIA and MidAmerican Energy personnel. All parties must understand the operation of the fuel cell and associated inverter. System protection during short term (or momentary) outages is a concern that should be discussed in detail with both organizations before installation so they are comfortable with the safety of the fuel cell installation.

It is vital for the safety of RIA linemen that the MCFC generator not come online unexpectedly, such as when the linemen are repairing a part of the system and do not expect another source of power to suddenly energize lines. The control scheme for the fuel cell must be designed to avoid this possibility.

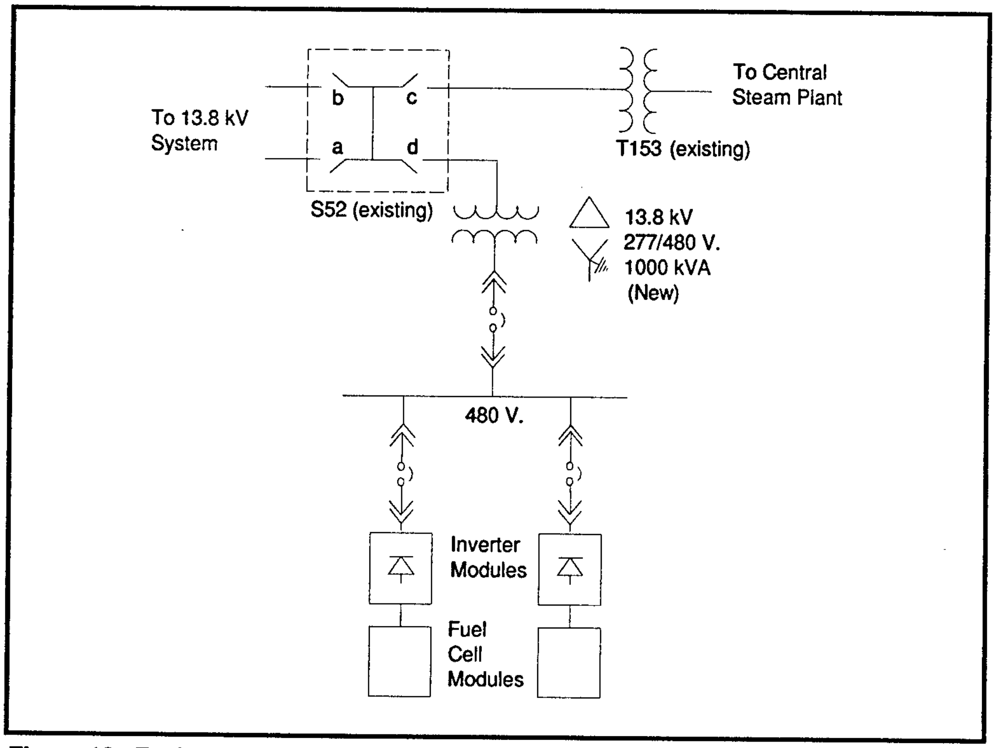


Figure 16. Fuel cell electrical interface.

The control system must have a positive means of detecting when the grid has lost power. The hydro plant operators must have a means of monitoring the status of the fuel cell, and a positive means of preventing the fuel cell from coming on line unexpectedly. This will most likely involve a new communication line to Substation A (to detect loss of utility) as well as a communication line with the hydro plant (for remote monitoring and control), where RIA electric system operators are located. The existing SCADA system at the hydro plant, which is Allen-Bradley PLC 5/20 and 5/60 units on a Data Highway Plus network, should be expanded to encompass monitoring and control for the fuel cell.

In the event of remote control malfunction, the linemen must also have an easy way to physically go to the fuel cell, monitor its status, and control its operation. The fuel cell on-site control design should include an emergency shut-down procedure to allow linemen to rapidly disconnect or shut-down the fuel cell in a manner that protects the distribution system and the fuel cell.

It has not been decided whether the boiler plant or the hydro plant personnel will be responsible for day-to-day operation of the fuel cell, or whether some other group will have this responsibility. Since the boiler plant may receive waste heat from the MCFC generator, it is likely that the boiler plant personnel will also monitor the fuel cell operation. The exact details of how boiler plant personnel would monitor the fuel cell are not defined yet, but such a system will probably be necessary.

Heat Recovery Interface

Two options considered for using heat recovered from the fuel cell are:

1. Connect to a condensate return line, pass the condensate through the fuel cell heat recovery steam generator (HRSG) and supply steam at 135 psig to the RIA summer steam main (preferred option).
2. Connect to the boiler make-up water supply line, use the fuel cell heat recovery heat exchanger (HRHX) to pre-heat the boiler make-up water.

Option A: Provide 135 psig Steam

This option has the benefit of being somewhat independent of the eventual future of the steam plant. Both the steam and condensate lines used could remain in operation if the central plant were retired. It would be possible to connect the fuel cell to the condensate return and steam supply lines that serve the manufacturing buildings to the west of the fuel cell location. This connection could be made approximately 150 ft north of the fuel cell site. The trench containing the piping would cross underground electric and gas utilities. Condensate would be piped from this location to a condensate receiver and pump located at the fuel cell site. Condensate would be pumped through the fuel cell heat recovery steam generator to produce steam at 135 psig, which would be piped in the same trench back to the steam supply main (Figure 17). If the boiler plant were retired and buildings served did not require 135 psig steam, the pressure of steam generated could be reduced.

An alternative connection to the steam supply and condensate return system could be made approximately 325 ft east of the fuel cell site. The trench containing the piping would parallel an existing 4-in. gas line and would not cross existing utilities. This connection to the steam system would serve buildings south of Kingsbury Avenue, and east of Gillespie Avenue.

Option B: Pre-Heat Boiler Make-up Water

After leaving the central plant water treatment system, boiler make-up water would be piped approximately straight south 150 ft to the fuel cell site. A pump located at the fuel cell site would pump the make-up water through the fuel cell HRHX (Figure 18). The heated water would then be piped to the suction of the central plant feedwater pumps. Piping for this connection will be about 150 ft each way, neglecting piping modifications within the central plant.

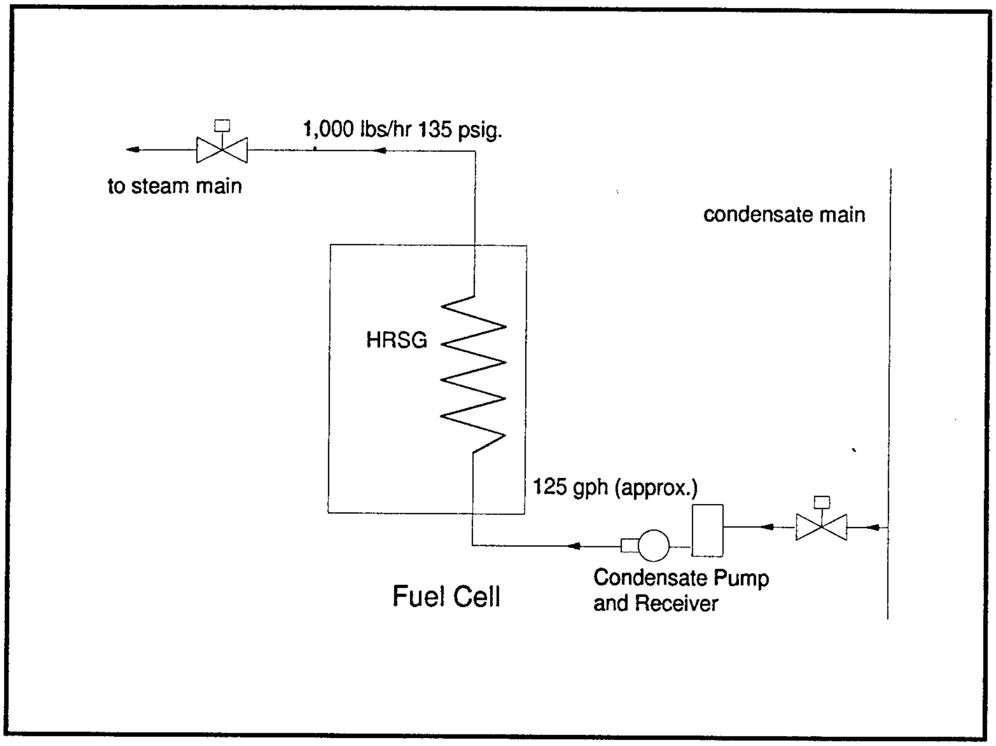


Figure 17. Thermal interface for heat recovery Option A.

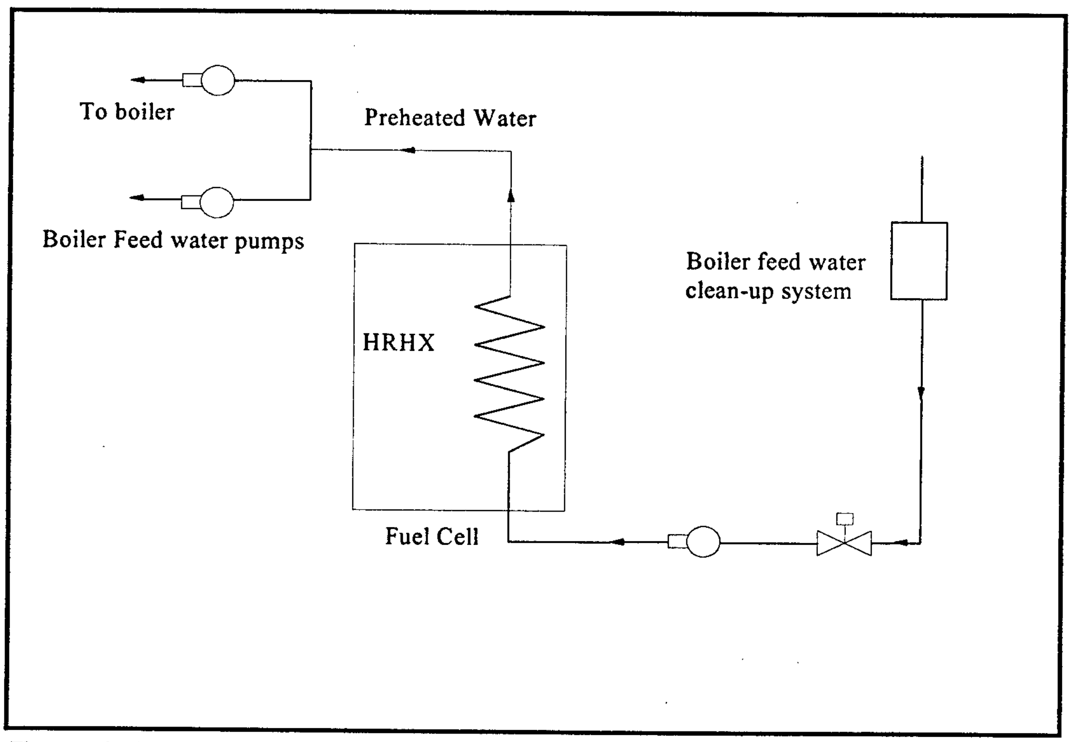


Figure 18. Pre-heat boiler make-up water Option B.

Impacts on RIA Electric and Thermal Loads

Overview

M-C Power's molten carbonate fuel cell produces both electric power and thermal energy in a highly efficiently manner with little environmental impact. The proposed fuel cell site, adjacent to the Central Heating Plant, will supplement the Arsenal's electric grid supply displacing purchases from the local utility (Mid-American Energy). The fuel cell will also augment the Arsenal's steam supply using heat recovered from some of the fuel cell stack exothermic reaction.

The Arsenal consumes about 89,975 MMBtu per month of energy on an equivalent Btu basis. Energy is consumed in the form of purchased natural gas, coal, and electricity. Coal purchases for the central steam plan is the largest energy component and makes up 67 percent of consumed energy. Figure 19 shows the breakout of the average monthly energy consumption for the Arsenal. Electricity supplied to the Arsenal includes power generated by the Arsenal's hydroelectric plant, which makes up 4 percent of total energy consumed.

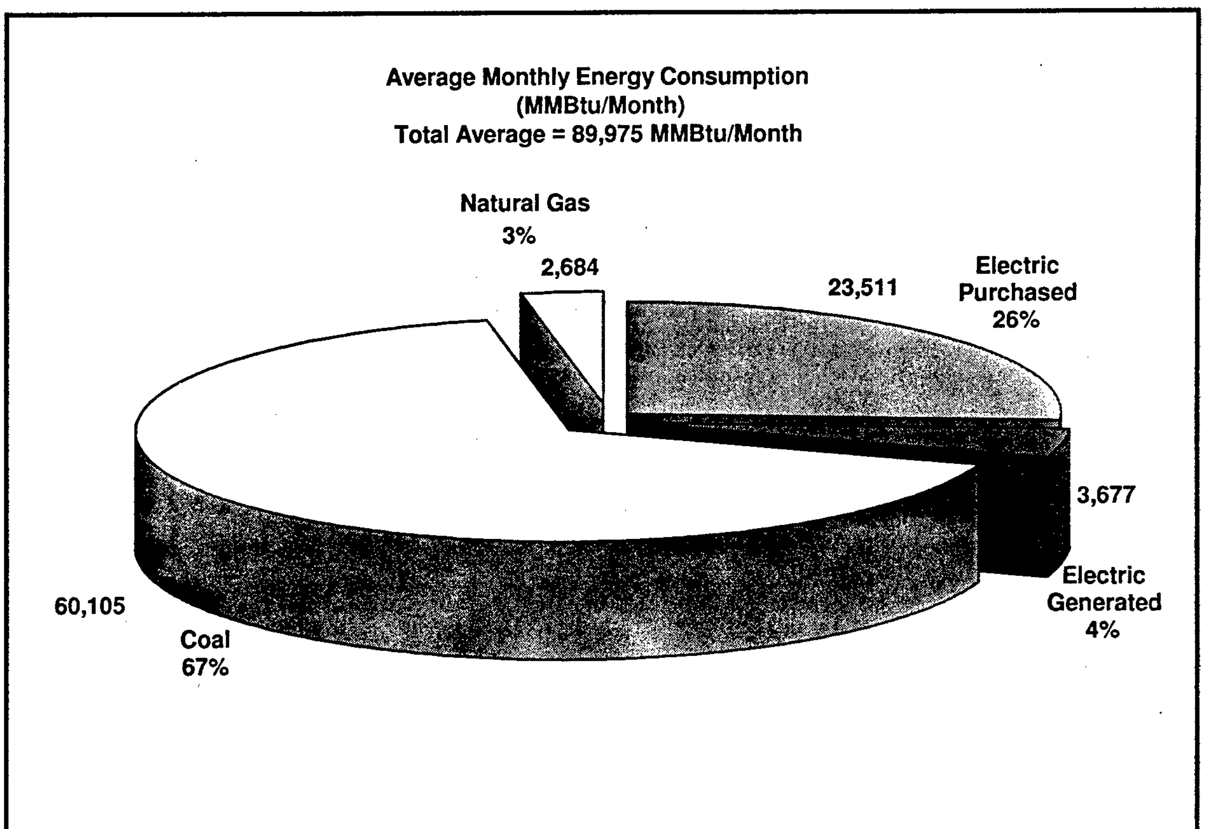


Figure 19. RIA average monthly energy consumption.

Historically, energy consumption for the Arsenal is highly seasonal. RIA's monthly energy consumption peaks at approximately 150,000 MMBtu, but has been as low as 55,000 MMBtu. The majority of the peak energy consumption is due to increased coal consumption, which occurs during the winter months. Figure 20 shows RIA's monthly energy consumption trend from 1992 to 1999.

RIA averages $443,300 per month of aggregate energy purchases.* Approximately 73 percent of those costs are from electric purchases from MidAmerican.† Twenty-five percent of energy costs are the result of coal purchases. Figure 21 shows the cost breakout of energy costs for the Arsenal.

Historical monthly energy cost trends (Figure 22) have indicated a decrease over time. This is partly due to reduced energy consumption (Figure 20), but appears to be primarily caused by decreased energy costs, particularly in electric and coal purchases.

Electric Load Impacts

RIA electric purchases are made from MidAmerican Energy at high voltage and are master metered at the MidAmerican Energy substation located at the southwest corner of the Arsenal. RIA is currently on MidAmerican's No. 53 commercial and industrial electric rate. This rate consists of a fixed service fee, and demand and energy charges are time-of-use and seasonally adjusted. Details are shown in Table 11.

Historically, RIA monthly purchased electric energy ranges from 4600 MWh to 9400 MWh with an average of 6,900 MWh per month. Purchased monthly peak demand ranges from 12,900 kW to 21,000 kW with an average of 17,000 kW. Figure 23 shows the profile of monthly energy and demand purchases as well as hydroelectric generation.

Table 12 summarizes RIA's seasonal average monthly purchased electricity characteristics and fuel cell power plant impacts on purchased electric energy and demand.

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* Note that electricity generated from RIA's hydroelectric plant is not included in this energy cost analysis.

† RIA purchases electricity from MidAmerican at high voltage that is received at the MidAmerican Energy substation #30 located at the southwest corner of the Arsenal.

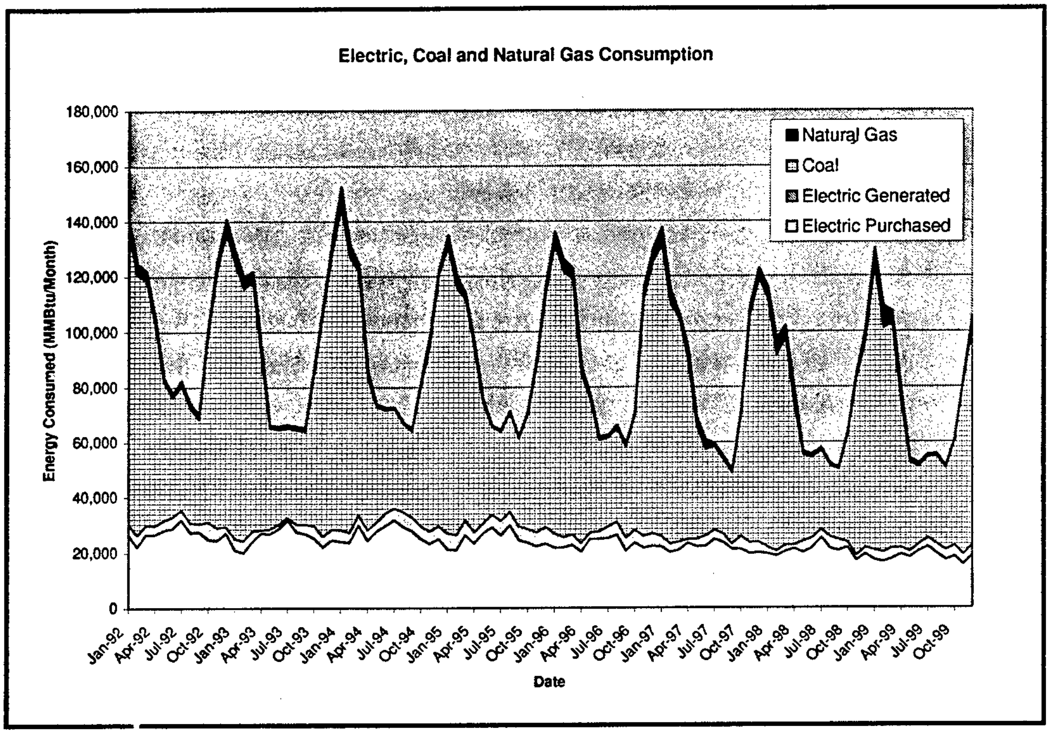


Figure 20. RIA monthly energy consumption trend.

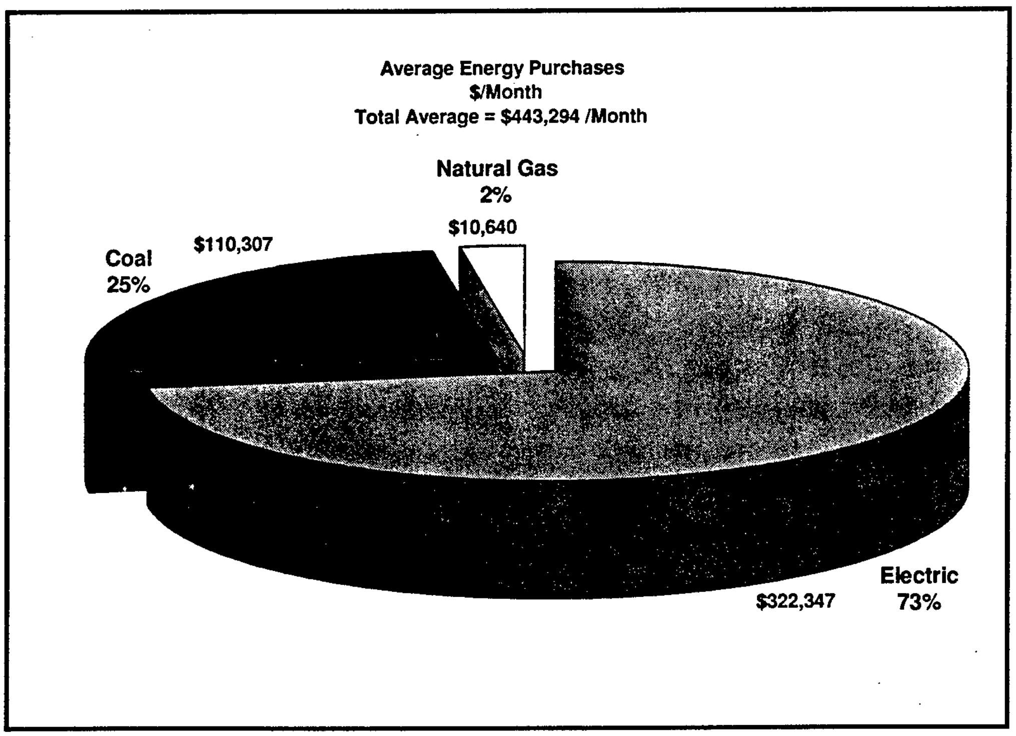


Figure 21. RIA average monthly energy costs.

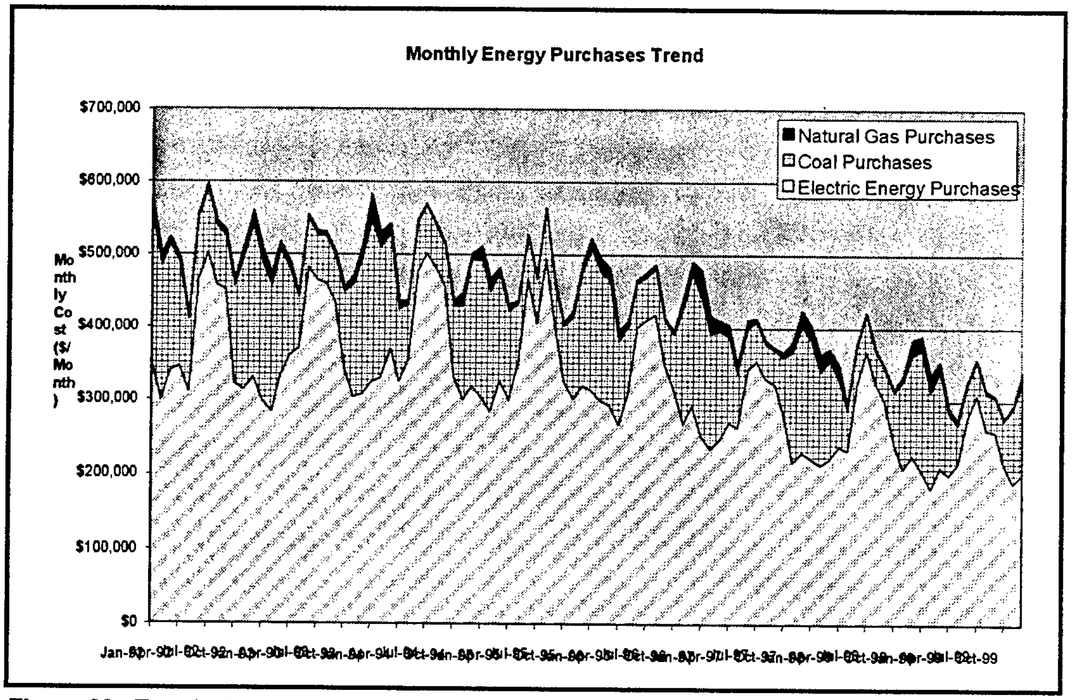


Figure 22. Trend of monthly energy costs.

Table 11. RIA electric rate schedule (No. 53).

Basic Service: * $477 per month		
Billing Demand Charge: All kW	Summer: $9.14 per kW	Winter: $4.98 per kW
Energy Charge:** On Peak - All kilowatt hours Off Peak - All kilowatt hours	 $0.03196 per kWh $0.02036 per kWh	 $0.03196 per kWh $0.02036 per kWh
Summer - Applicable during the four monthly billing periods of June through September.		
Winter - Applicable during the eight monthly billing periods of October through May.		
On Peak Hours - Daytime periods between 8:00 a.m. and 8:00 p.m. Monday through Friday during the month excluding the United States legal holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.		
* Source: MidAmerican Energy, Effective 1 January 1988. ** Includes a $0.019/kWh nuclear decommissioning charge and -$0.004/kWh gas field cleanup credit per Greg Schaeffer of MidAmerican Energy.		

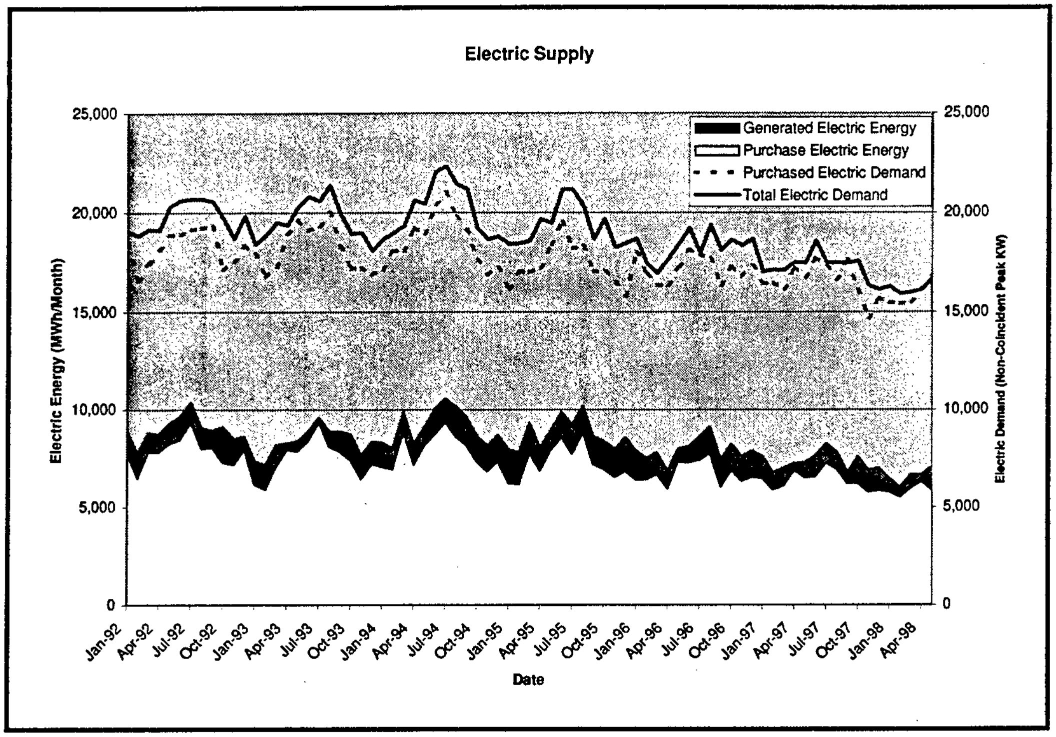


Figure 23. Historical RIA monthly electric energy and peak demand.

Table 12. RIA electric purchases and fuel cell output comparison.

	Summer[1]	Winter
No. months (per MidAmerican Energy)	4	8
RIA average electric energy purchased (MWh/month)	7,500	6,600
Fuel cell energy output (MWh/month)[2]	657	657
Potential RIA electric energy reduction	8.8%	10.1%
RIA average electric demand (peak kW per month)	17,300	16,600
Fuel cell capacity (peak kW/month)[3]	1,000	1,000
Potential RIA electric demand reduction	5.8%	6.0%

1 Averages calculated from historical data: January 1992 to December 1999.
2 Assumes 90% availability for 1 MW MCFC power plant.
3 Assumes that fuel cell is at full load (1 MW) coincident with peak demand.

Key to these electric energy and demand purchase reductions is baseloaded operation of the fuel cell power plant without reducing the inexpensive hydroelectric power generated within the Arsenal. Earlier work, in this study has shown that the minimum purchased electricity demand of the Arsenal is 4 MW. Therefore, the baseload operation of the 1 MW fuel cell is anticipated to be feasible and will not result in any turndown of the hydroelectric production.

Thermal Load Impacts

The RIA Central Steam Heating Plant provides heat for space and process heating throughout the Arsenal. It uses Eastern Kentucky coal, which is burned in four steam boilers: two rated at 100,000 lb/hr; two others rated at 125,000 lb/hr and 75,000 lb/hr each. Steam is generated at 135 psig and 352 °F saturated vapor conditions. The smaller boiler, which services the manufacturing area, is used primarily for summer loads. Figure 24 shows the heating plant steam production and the monthly average cost of steam for the past 7 years.

Steam production peaks during the winter months at approximately 90,000 lb/month and falls off to 19,000 lb/month during the summer months. There has been a gradual decrease of summer load over the past 7 years. Steam costs have been decreasing since 1992 and are now approximately $2.20/1000 lb of steam. The steam cost reduction trend is primarily due to decreasing costs of coal, which have dropped from $48/ton to $42/ton.

The fuel cell power cogenerates approximately 1.18 MMBtu/hr of useable thermal energy. This thermal energy can augment the central heating plant steam output or preheat boiler make-up to avoid the coal consumption. Table 13 documents the impact of the heat recovered from the fuel cell on steam production.

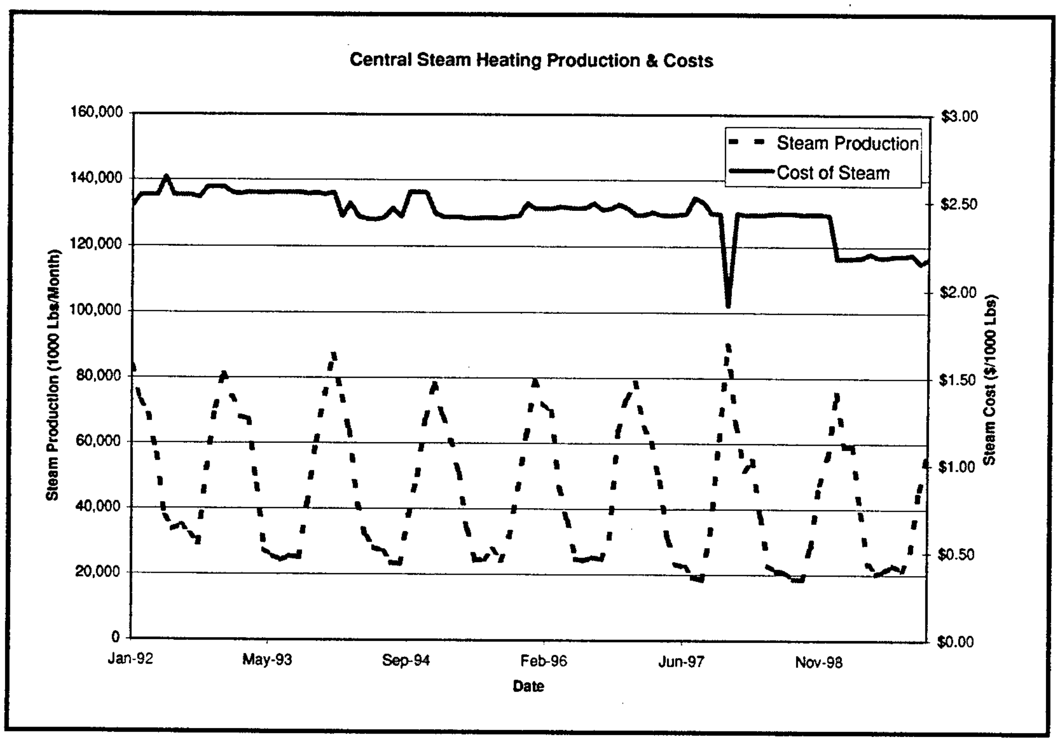


Figure 24. Historical RIA steam production and cost.

Table 13. RIA steam production and fuel cell thermal output.

	Summer[1]	Winter
No. months (per MidAmerican Energy)	4	8
RIA average steam production (1,000 lb steam/month)	24,388	55,634
Steam production efficiency (1,000 lb steam/MMBtu coal)	0.747	0.751
Coal consumption (MMBtu/month)	32,648	74,080
Fuel cell thermal output (1,000 lb steam/month)[2]	775	775
Avoided coal consumption (MMBtu/month)[3]	1,038	1,032
Potential RIA coal energy reduction	3.2%	1.4%

1 Averages calculated from historical data: January 1992 to December 1999.
2 Assumes 90% availability for 1 MW MCFC power plant.
3 Assumes 1,000 Btu per Lb of steam.

Economic Analysis

To determine the net economic benefit of the MCFC power plant, the operating costs for the fuel cell power plant must be established. The analysis assumes that through congressional appropriations, the Department of Defense (DOD) will provide the funds for capital and installation. Therefore, the net economic benefit to the Arsenal is the difference between avoided energy costs and the fuel cell operating cost.

Fuel cell operating costs are primarily fuel costs for the plant. Fuel costs are a function of fuel cell electric conversion efficiency and natural gas price. The M-C Power fuel cell is designed to operate at a heat rate of 6,560 Btu/kWh (LHV), or 7,216 Btu/kWh HHV (which assumes a 10 percent increase in fuel heating value). Figure 25 charts RIA natural gas fuel price trends. They show that, for the most part, natural gas cost stays between $3 to $5 per MMBtu with a 7-year average of $3.96/MMBtu. However, there were spikes in natural gas costs in early 1998. It is not known if these were anomalies or true price spikes.

Table 14 summarizes the costs associated with operating the fuel cell power plant.

The net economic benefit can be determined using the fuel cell operating cost data and known costs of energy for the Arsenal. Table 15 summarizes the fuel cell net monthly economic benefit.

Monthly economic benefits from the fuel cell are nearly $11,000 per month during the summer and about $5,000 per month during the winter. This results in an annual benefit of $84,580. Figure 26 illustrates the energy costs savings by season.

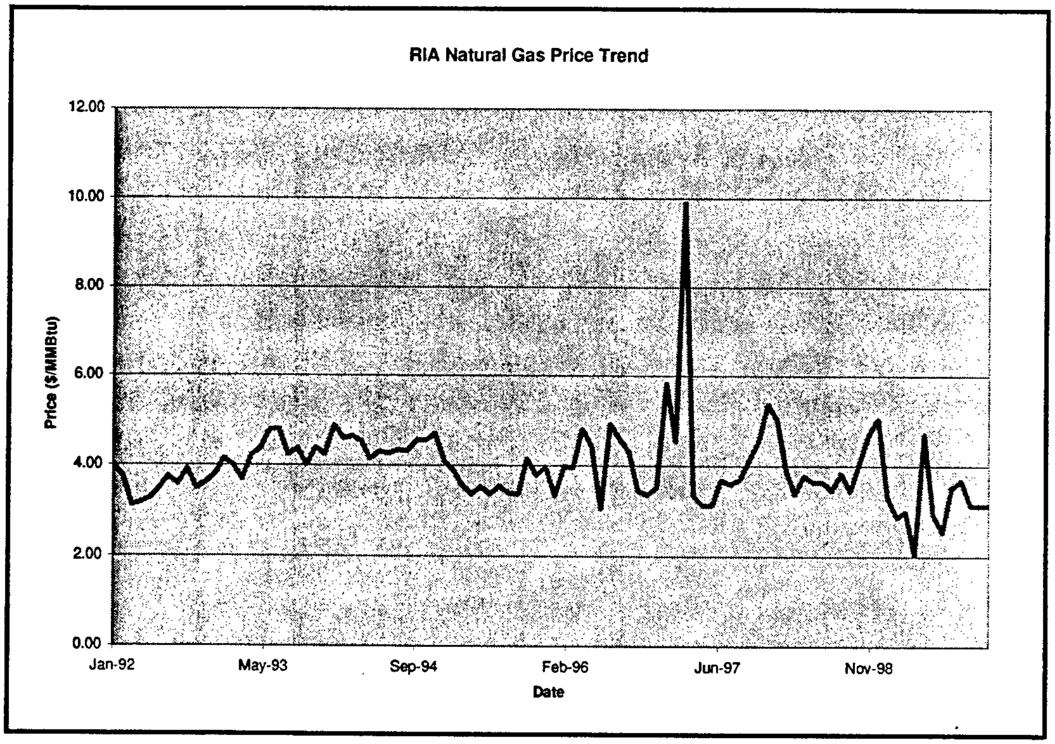


Figure 25. RIA natural gas price trend.

Table 14. Project fuel cell operating costs.

	Summer	Winter
No. months (per MidAmerican Energy)	4	8
Average fuel cell electric production (kWh/month)*	657,000	657,000
RIA average natural gas price ($/MMBtu)	$3.80	$4.04
Fuel cell heat rate (Btu/kWh HHV)	7,216	7,216
Average fuel cell fuel consumption (MMBtu/month)	4,741	4,741
Total fuel cell operating costs ($/month)	$18,016	$19,154
* Assumes 90% availability.		

Fuel Cell Impacts on Central Plant

General

The siting of a 1 MW fuel cell at RIA may provide a significant benefit to the Arsenal in terms of maintaining operations during extended power outages (on the order of days or weeks). Specifically, the fuel cell electric output, coupled with output from the RIA hydroelectric plant, may allow start-up and operation of the central heating plant using fuel cell and hydropower alone. The capability could be very useful in the event of a winter season electric power outage, such as could be caused by a major ice storm. In such a case, the central plant could heat the majority of installation buildings during the outage.

Table 15. Net economic benefit of MCFC power plant installation.

	Summer	Winter
No. months (per MidAmerican Energy)	4	8
Avoided electric energy (MWh/month)	657	657
Off-peak (MWh/month)*	388	348
Value of off-peak ($/kWh)	$0.03196	$0.03196
On-peak (MWh/month)	269	309
Value of on-peak ($/kWh)	$0.02036	$0.02036
Electric energy savings ($/month)	$17,873	$17,416
Avoided electric demand (monthly peak kW)	1,000	1,000
Value of electric demand ($/kW)	$9.14	$4.98
Electric demand savings ($/month)	$9,140	$4,980
Avoided steam production (1,000 lb/month)	775	775
Value of steam ($/klb)	$2.437	$2.436
Coal savings ($/month)	$1,888	$1,888
Fuel cell operating costs ($/month)	$18,016	$19,154
Net economic benefit ($/month)	$10,886	$5,130

*On/off peak breakout estimated using on-peak fraction of 0.47 for winter and 0.41 for summer calculated from average 1998 & 1999 billing data.

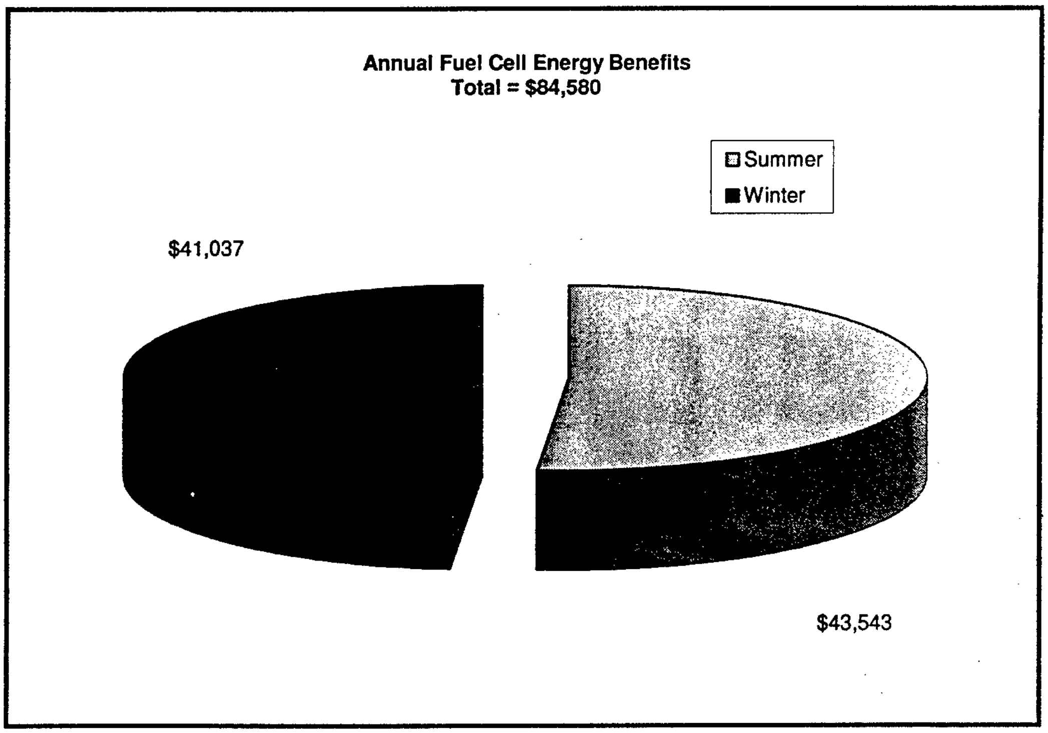


Figure 26. Fuel cell annual energy cost savings.

This section of the report explores the possibility of operating the central heating plant using fuel cell power. The first portion of this section describes the central plant configuration and present data on central plant energy usage and output.

The second portion describes the power requirements of central plant ancillary equipment and estimates the ability of the fuel cell to meet these requirements.

Description of Central Plant Equipment

Four boilers are located at the central steam plant. Boilers No. 1 and No. 2 were manufactured by Babcock and Wilcox in 1941 and 1942. These boilers are watertube types equipped with chain grate, heat exchanger, economizer, multicone fly ash collector, and forced, induced, and over-fire fans. The Boiler No. 2 induced draft fan uses a variable frequency drive. The boilers are rated at 1200 HP, 100,000 lb of steam/hr at 135–150 psig pressure. Currently these boilers provide steam at 135 psig.

Boilers No. 3 and No. 4 were manufactured by Wicks in 1963 and 1966. The boilers are watertube types equipped with spreader stoker, traveling grate, multicone fly ash collector, heat exchanger, economizer, and forced, induced, and over-fire fans, and one variable frequency drive for Boiler No. 3 induced draft fan. Boilers No. 3 and No. 4 have fly-ash re-injection and automatic blow downs. Boiler No. 3 is rated at 1500 HP, 125,000 lb of steam/hr at 135-150 psig pressure. Boiler No. 4 is rated at 960 HP, 75,000 lb of steam/hr at 135-150 psig. Both boilers currently provide steam at 135 psig.

The boilers are served by four feedwater pumps and four condensate transfer pumps. Two of the feedwater pumps are steam-driven and two are electrically-driven.

The boilers are served by two baghouses manufactured by Zurn in 1981. There are 10 compartments per baghouse, with 154 bags per compartment. The baghouses employ reverse air cleaning.

Boiler log data provided by RIA for January 1999 indicate an average central plant efficiency of 76 percent assuming condensate entering the boilers at 212 °F, steam production at 135 psig, and coal heating value of 12,800 Btu/lb. During this time period, Boilers No. 1 and No. 3 were in operation.

Figure 27 shows the condensate return data for January. The data indicate that, for the time period, the percent condensate returned was between 70 and 90 percent.

The boiler log provided by RIA also includes ambient temperature data. This allowed developing a regression of fuel input as a function of outside temperature (Figure 28).

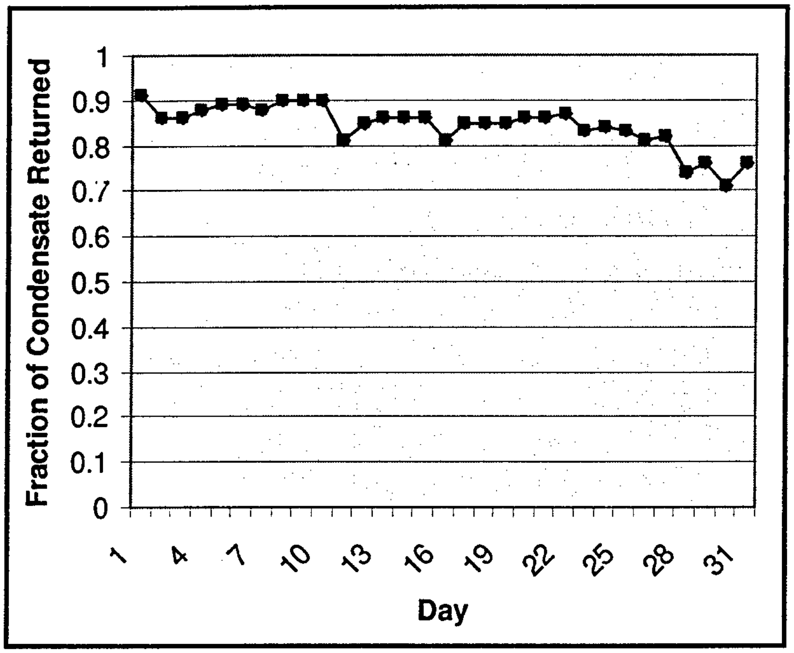


Figure 27. Central plant condensate return.

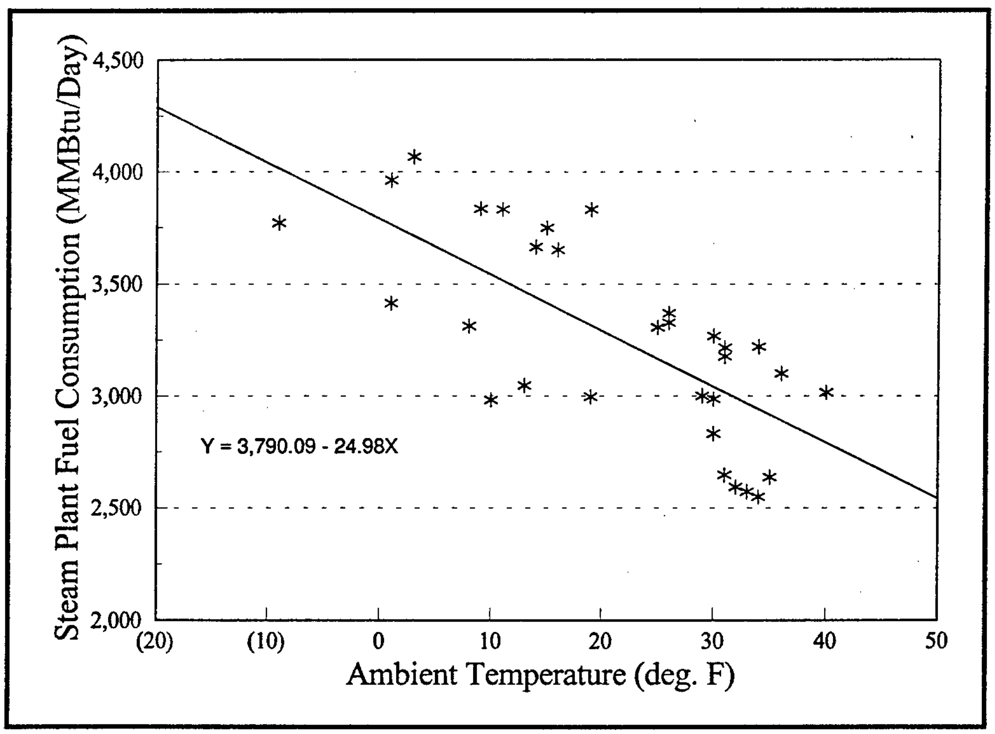


Figure 28. Regression of steam plant energy consumption.

Electrical Energy Usage

Electricity is supplied to the Steam Plant through three distribution circuits, and each is submetered. As discussed in the Phase I chapter, electrical usage peaks during the winter months and is dependent on the number of boilers in operation. Usage varies between a minimum of about 300,000 kWh and a maximum of 1,200,000 kWh. Maximum noncoincident demand was 1267 kW in January 1998 and was 816 kW in August 1998.

Fuel Cell as Central Plant Back-Up Power

Rock Island Arsenal conducted a preliminary study as part of its Y2K preparedness activities to examine the feasibility of operating one or two central plant boilers using power supplied by the hydro plant (Appendix C). The RIA analysis for running loads indicates that operation of Boilers No. 2 and No. 3 requires 978 kW, while running Boiler No. 3 alone requires 685 kW. The RIA analysis does not consider start-up loads. These loads are analyzed here in a simplified manner. This assumes that Boiler No. 3 is cold-started, and also that a unit start-up sequence is based on starting the largest horsepower motors first. Examination of the required equipment suggests that this is a feasible start-up sequence. In addition, the largest motor—400 HP for the boiler induced draft fan—is an adjustable speed drive so that some type of soft start capability exists. Table 16 lists the assumed unit start sequence.

Table 16. Boiler #3 equipment start-up sequence.

Starting Order	Sorting Label	Unit Label					Loads Required for 1 Boiler		
							H.P.	% Duty	Net HP
1	FAN	IDF	227	3		3	400	100	400
2	PUMP	ASP	227	R		1	100	25	25
3	PUMP	BFP	227	1		1	60	100	60
4	FAN	FDF	227	1	DM	3	50	100	50
5	FAN	RAF	227	1	BH	1	50	30	15
6	FAN	RAF	227	2	BH	1	50	30	15
7	MTR	AC	227	1	D	3	25	100	25
8	MTR	CGM	227	B		1	25	100	25
9	PUMP	CP	227	1		3	25	100	25
10	PUMP	CP	227	1		4	25	100	25
11	PUMP	RBP	227	1		1	25	10	2.5
12	FAN	CAF	227	1	DM	1	25	100	25
13	MTR	AC	227	1	D	1	15	100	15
14	PUMP	FBP	227	1		1	15	100	15
15	PUMP	TWP	227	1		1	15	100	15
16	PUMP	ZBP	227	2		1	15	100	15
17	MTR	BTM	227	3		1	10	100	10
18	MTR	CEM	227	3		1	10	100	10
19	FAN	EF	227	B	D	1	10	50	5
20	MTRT	ATM	227	2		1	5	100	5
21	MTR	PEM	227	B		1	5	100	5

Starting Order	Sorting Label	Unit Label					Loads Required for 1 Boiler		
							H.P.	% Duty	Net HP
22	FAN	EF	227	B		1	5	40	2
23	MTR	AC	227	3		1	3	0	0
24	MTR	AC	227	3		2	3	0	0
25	PUMP	BTP	227	1		1	3	5	0.15
26	PUMP	RP	227	B		1	3	100	3
27	PUMP	SRP	227	1		1	3	100	3
28	FAN	EF	227	R		1	3	100	3
29	MTR	CCM	227	B		1	2	40	0.8
30	MTR	SFM	227	1		1	2	100	2
31	PUMP	FBTP	227	2		1	2	100	2
32	MTR	LMM	227	1		1	1.5	100	1.5
33	PUMP	BRP	227	1		1	1.5	50	0.75
34	MTR	AC	227	1		1	1	100	1
35	MTR	AUM	227	2		1	1	100	1
36	MTR	BBM	227	3		1	1	100	1
37	PUMP	CP	227	B		1	1	100	1
38	AHU	AHU	227	2		1	1	100	1

Based on the starting order shown in Table 16, running and start-up loads were estimated by calculating running loads based on 90 percent motor efficiency, and start-up loads for all but the adjustable speed drive were estimated as four times the running load (Figure 29). The adjustable speed drive start-up load was assumed to be twice the running load. The results suggest that using the assumed start-up sequence that motor inrush loads will not exceed the 1 MW fuel cell output capacity. It appears then that, with adequate planning and careful load management, the fuel cell is capable of cold-starting the RIA central plant No. 3 boiler. Note that this calculation of running load does not agree exactly with the RIA analysis because it does not take credit for duty cycle, but assumes that all loads are coincident. Also, the effect of step load changes on the fuel cell power plant will have to be assessed to determine the compatibility of this load sequencing with the fuel cells dynamic load rate capability.

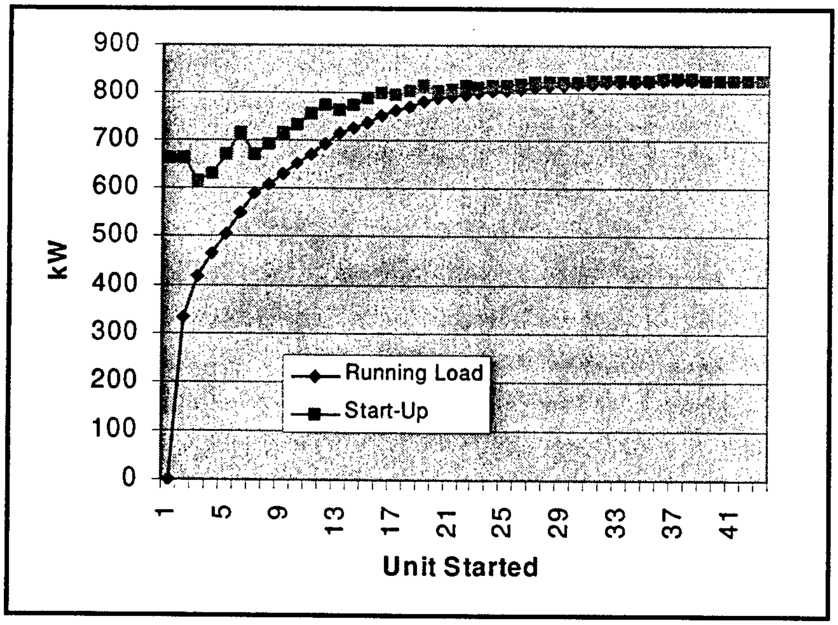


Figure 29. Estimated starting and running loads for Boiler #3.

Aid to Eliminating Central Plant Summer Usage for Chillers

During the cooling season, the central steam plant is used for supplying nearly 32,000 lb/hr of steam for operating six absorption chillers with a total capacity of about 2500 RT. Table 17 lists some information on the characteristics, capacity, age, and location of these absorption chillers. RIA is planning to initiate a study to evaluate the feasibility of retiring the central steam plant that contains coal-fired boilers and of replacing it with gas-fired packaged boilers and geothermal heat pumps. Switching boiler fuels from coal to natural gas will increase the variable fuel cost for producing 1000 lb of steam from an average $2.437 to $3.80, or about 56 percent. This section of the report discusses the impact of the proposed fuel cell power plant as an aid to eliminating central plant's summer usage for chillers.

Table 17. Data on existing steam-driven absorption chillers at RIA.

Location / Building No.	Chiller Characteristics	Installation Year	Rated Capacity RT	Steam Need lb/hr
348	Double-Effect	1976	750	9,150
350	Single-Effect	1987	150	2,805
350	Single-Effect	1970	150	2,805
73	Double-Effect	N/A[1]	385	4,697
114	Double-Effect	N/A[1]	527	6,429
114	Double-Effect	N/A[1]	527	6,429
		Total	2,489	32,315

As shown in Table 13, the fuel cell is estimated to co-produce 775,000 lb/month (1,062 lb/hr) of steam, or about 3 percent of the total steam required for operating all the absorption chillers. Since this quantity of steam is not adequate for eliminating the central plant usage for the existing absorption chillers, the following options have been evaluated for replacing the absorption chillers with new chillers that will eliminate the central plant use for chillers:

1. Electric chillers
2. Electric chillers with ice storage
3. Hybrid chiller plants.

Table 18 lists the parameters to make a qualitative comparison of the above three options. Table 19 lists quantitative economic impacts of each of these options.

Since the cooling load profile for the RIA facility was not available, the quantitative impacts shown in Table 19 have been estimated assuming a simplified cooling load profile (Figure 30), which implies the following assumptions:

1. Baseline cooling load: 1600 tons
2. Maximum cooling load: 2500 tons
3. Average daily peak cooling period: ~ 4 hr
4. Average annual equivalent full-load operating periods
5. Baseline cooling load 1500 hr (1000 hr at off-peak rates + 500 hr at on-peak rates)
6. Maximum cooling load 500 hr (at on-peak rates).

The estimates do not include the cost for dismantling the old absorption chillers and clearing up the site for the new electric chillers.

A detailed discussion on each of the three options for replacing the absorption chillers follows.

Electric Chillers (Option 1)

This option for eliminating summer usage of the central plant requires replacing all absorption chillers with new high-efficiency electric centrifugal chillers (0.6 kW/ton). Compared to the current electric power demand at the RIA facility, this option will create an additional electric power demand up to 1.5 MW for the 2500 RT cooling capacity of these chillers. This option will, however, make the cogenerated thermal energy (1062 lb/hr of steam), from the fuel cell plant, available for any of the several process steam applications at RIA.

Table 18. Qualitative comparison of the various options for replacing the existing absorption chillers.

Chiller Option	Positive Features	Negative Features
1. Electric Chillers	• Requires least capital for the new chillers • Does not need the co-produced steam (from the fuel cell plant) for chillers and thus makes it available for other process steam applications.	• Increases reliance on purchased power than the present cooling system. • Does not prepare to benefit from electric deregulation when the differences between the on-peak and off-peak electric rates could be higher than those RIA is currently paying. • Does not prepare to benefit from electric deregulation when the differences between the on-peak electric rates and natural gas costs could be higher than those RIA is currently paying.
2. Electric Chillers with Ice Storage	• Better prepares than Option 1 to benefit from increased differential between on-peak and off-peak electric rate after electric deregulation. • Does not need the coproduced steam (from the fuel cell plant) for chillers and thus makes it available for other process steam applications.	• Requires slightly higher capital investment than Option1. • Increases reliance on more purchased power than the present system. • Does not prepare to benefit from increased energy cost differential between on-peak electric and natural gas rates after electric deregulation.
3. Hybrid Chiller Plants		
3.1 With a New 750-ton Direct-Fired Absorption Chiller and the existing 150-ton Steam-Heated Single-Stage Absorption Chiller	• Requires less capital than Option 3.2 • Direct-fired absorption chiller can be used as a boiler during winter	• Requires more capital than Options 1 and 2 • Higher natural gas cost for operation than Option 3.2.
3.2 With a New 750-ton Engine-Driven Chiller and the existing 150-ton Steam-Heated Single-Stage Absorption Chiller	• Best prepares to benefit from electric deregulation when cost differential between on-peak electric and natural gas rates is high.	• Requires the most capital to install the chiller system

One of the advantages of the fuel cell plant will be its capacity to supply up to 1 MW, or about 67 percent of the total power demand by the electric chillers, without RIA having to pay any demand charge. In addition, since the capital cost for the fuel cell plant for the demonstration project will be paid for by entities other than RIA, the cost of electric energy from this plant is estimated to be only $0.0274/kWh (Table 14). This electric energy cost is lower than the current average on-peak rate for the purchased electric energy.

Table 19. Economics of various chiller options for replacing the current capacity of the absorption chillers.

Chiller System Option	1	2	3.1	3.2
Capital Cost[1]				
Chillers	$1,250,000	$950,000	1,525,000	$1,550,000
Ice Storage		$360,000		
Credits			($88,000)	
Saving Boiler Cost				
Total	$1,250,000	$1,310,000	$1,437,000	$1,550,000
Annual Demand Charge	$19,700	$8,200	$0	$0
Annual Electric Energy Cost				
On-Peak				
Fuel Cell Generated	$26,300	$26,300	$27,100	$26,300
Purchased	$8,600	$0	$0	$0
Off-Peak				
Fuel Cell Generated	$26,300	$26,300	$26,300	$26,300
Purchased	$0	$4,600	$0	$0
Credits				
Unused Fuel-Cell Generated Power				
Total	$61,200	$57,200	$53,400	$52,600
Annual Natural Gas Cost			$14,300	$9,000
Annual Maintenance Cost	$57,500	$43,700	$59,800	$48,300
Total Annual O&M Cost[2]	$138,500	$109,100	$127,500	$109,900

1. All costs based of historical average energy rates at RIA.
2. Total of annual demand charge, electric energy cost, natural gas cost, and maintenance cost.

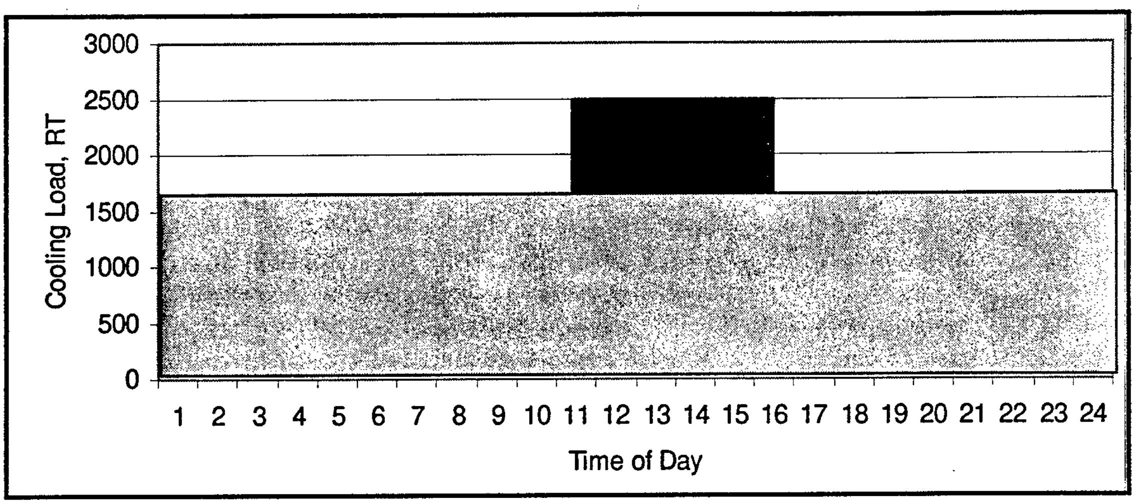


Figure 30. Simplified cooling load profile for the absorption chillers at RIA.

The installed cost for the new electric chillers is estimated to be about $1.25 million for the 2500 tons of total installed capacity assuming $500/ton installed cost for these chillers.

The annual energy cost for operating the electric chillers is estimated to total $80,900 including $19,700 for the annual demand charge and $52,600 for the electric energy from the fuel cell plant and $8,600 for the purchased electric energy. Assuming an annual maintenance charge of $23/ton for the electric chillers, total annual maintenance cost is estimated to be about $57,500. Therefore, the annual energy and maintenance charge for this chiller system option is estimated to total nearly $138,400.

These estimates are based on the historical average costs for energy at RIA. However, in view of the impending full electric power deregulation in Illinois by the end of 2000, the electric rate structure for the purchased power might change significantly from the historical data.

In the deregulated electric energy market, even though the average cost of electric power is expected to decrease, electric energy rates during on-peak hours are expected to increase, especially during summer when the demand for electric power peaks due to air-conditioning loads. Table 20 gives an example of the effect of electric energy deregulation on the electric energy cost during summer. These rates were being offered last year by an electric energy wholesaler. If similar rate changes occur at the RIA, it will further enhance the value of the fuel cell plant, which will continue to produce power at a nearly fixed cost.

Under the environment of a deregulated electric energy market, for every $0.01/kWh increase in the on-peak electric energy cost, the annual energy cost for this option will increase by $2700. However, if the off-peak rate decreases by $0.01/kWh, RIA will not be able to benefit from this reduction.

Table 20. An example of electric energy rates in the Midwest under the deregulated market.

Month	Price, $/MWh (16 hours per day for 5-Days a week)
January, February, and May*	27
March, April	21
June	64
July, August	127
September	37
October, November	23
December	22

* D.V. Punwani, et al., *Combustion Turbine Inlet Air Cooling Using Absorption Chillers: Some Technical and Economic Analyses, and Case Summaries*, Paper presented at ASHRAE meeting (Toronto, June 1999).

Chiller Systems with Ice Storage (Option 2)

Another option for replacing the absorption chillers is to install new electric chillers and a new ice storage facility. The ice storage facility will allow RIA to take advantage of the low electric energy rates during the off-peak hours (8 p.m.-6 a.m.) by using electric chillers during this period for producing ice and then using the stored ice to produce chilled water to meet peak cooling loads during the day. This option also helps reduce the total installed capacity and the cost of electric chillers.

Based on these assumptions, the average daily peak cooling load period is 4 hours, the baseline cooling load is 1600 tons, and the total installed chiller capacity needed is 2500 tons, the total cooling capacity of the ice storage should be 3600 ton-hr. (The difference between total and baseline cooling capacities time is 4 hr). To produce this cooling capacity of the ice storage over the 12 hr of off-peak electric rates, the capacity of the ice generator should be 300 tons.

Capital cost for the 1600 tons of electric chillers is estimated to be $800,000. Capital cost for the 300-ton ice generation system is estimated to be about $150,000. Even though the installed costs for the ice generator and the other electric chillers are the same, $500/ton, the chiller for the ice generator will require 0.75kW/ton instead of 0.6/kWh for the water chiller because it will have to operate at lower evaporator temperatures. Capital cost for the 3600 ton-hr (900 tons of cooling for 4 hr) of ice storage is estimated to be about $360,000. Therefore, the total capital cost for the system with electric chillers and ice storage is estimated to be $1.31 million.

The annual energy cost for operating this chiller option is estimated to total $65,400, including $8,200 for the annual demand charge, $52,600 for the electric energy from the fuel cell plant, and $4,600 for the purchased electric energy. Assuming an annual maintenance charge of $23/ton for the electric chillers, total annual maintenance cost is estimated to be about $43,700. Therefore, the annual energy and maintenance charge for this chiller system option is estimated to total nearly $109,100.

In comparison with Option 1, Option 2 requires about $60,000 more in capital investment. However, this option has the potential of reducing the annual energy and maintenance costs of about $18,000.

Under the environment of a deregulated electric energy market, for every $0.01/kWh decrease in the off-peak electric energy cost, the annual energy cost for this option will decrease by $2200 for operating the ice generator. However, if the on-peak rate increases by $0.01/kWh, RIA costs will remain unchanged for this option.

Hybrid Chiller Plants (Option 3)

One of the popular strategies to deal with uncertain energy costs after the power market is deregulated is to choose a hybrid chiller plant that consists of a mix of electric and non-electric chillers. A hybrid chiller plant will allow RIA to take advantage of the lowest price energy source at any given time and will provide a good hedge against uncertain future energy rates. For example, during peak electric demand periods (usually daytime during summer), when the electric energy rates could be very high, gas-fired or steam-heated chillers can be operated as lead chillers up to their maximum capacities to reduce on-peak electric energy charges. Alternatively, electric chillers can be run as lead chillers at night when the electric energy rates are generally low. The flexibility to control electric power demand will also allow RIA to negotiate the best deal with the electric power suppliers in the deregulated market.

As shown in Table 17, the 750-ton steam-heated double-effect chiller in Building 348 is more than 20 years old. It can be replaced with any one of the several non-electric chillers. Even though there are many possible combinations for hybrid chiller systems, this study discusses only the following two combinations of non-electric chillers with the electric chillers and evaluates their potential economic benefits:

1. A new 750-ton direct-fired absorption chiller and an existing 150-ton steam-heated absorption chiller
2. A new 750-ton natural gas engine chiller and an existing 150-ton steam-heated absorption chiller.

In both of these hybrid chiller systems, it is assumed that the maximum demand from the electric chillers will be maintained so as not to exceed about 1 MW so that it could be supplied by the fuel cell power plant. Therefore, no purchased power will have to be used for operating any of the above hybrid cooling systems. In addition, it is assumed for both of the hybrid chiller systems that the 150-ton steam-heated, single-stage absorption chiller installed in 1987 in Building 350 will be kept in service.

Hybrid Chiller Plant with a New 750-ton, Direct-Fired Absorption Chiller (Option 3.1)

In this option, a new, 750-ton, direct-fired, double-effect absorption (DFA) chiller is deployed to replace the aging 750-ton double-effect steam-heated chiller in

Building 348. Even though the capacity of the other absorption chiller (steam-heated single stage) is 150 tons, its output will be limited to only about 50 tons. This limitation stems from the availability of steam. Since the fuel cell power plant can only supply 1060 lb/hr of steam, instead of 2800 lb/hr needed for the chiller's full capacity. Electric chillers provide the remaining 1700 tons of chiller capacity required for achieving total installed capacity of 2500 tons. Total capital cost for the Chiller System Option 3.1 is estimated to be $1.525 million, including $0.85 million for the 1700 tons of electric chillers and $0.600 million for the DFA chiller assuming $800/ton installed cost.

One of the advantages of the modern DFA chillers is that they can also be used as boilers during winter. A 750-ton DFA chiller can serve as a 7.2 million Btu/hr boiler during winter. Therefore, this chiller option could save RIA nearly $88,000 in new boiler gas-fired packaged boilers for modernizing its central plant. Hence the net capital cost for this chiller option would be only $1.437 million.

The annual energy cost for operating this chiller option is estimated to total $67,700, including $0 for the annual demand charge (because no power is purchased), $53,400 for the electric energy from the fuel cell plant, and $14,200 for natural gas. Assuming an annual maintenance charge of $23/ton for the electric and both types of absorption chillers, total annual maintenance cost is estimated to be about $59,800. Therefore, the annual energy and maintenance costs for the hybrid chiller plant Option 3.1 are estimated to total nearly $127,500.

Hybrid Chiller Plant with a New 750-ton Natural Gas Engine Chiller (Option 3.2)

This hybrid chiller option is similar to that of Option 3.1, except that this option uses a natural gas engine chiller instead of a new DFA. This chiller system option has the following advantages over Option 3.1:

1. It allows operation of the steam-heated chiller at its maximum capacity of 150 tons.
2. It reduces the capacity needed from the new electric chillers from 1700 tons to 1600 tons.

These advantages accrue from the modern natural gas engine chillers because these chillers achieve a high fuel efficiency of 75 percent. These chillers are very desirable for applications that have coincident demand for both cooling and heating. Nearly 45 percent of the fuel energy supplied to an engine-driven chiller is available as recoverable heat from the engine exhaust (15 percent) and engine-jacket coolant (30 percent). A typical modern engine chiller has a full-load Coefficient of Performance (COP) of 1.9. Therefore, from a 750-ton engine chiller, nearly 2100 lb/hr of steam could be available for operating the steam-heated absorption chiller. The steam available from the engine-chiller together with that available from the fuel cell plant is more than adequate to meet the maximum 2800 lb/hr steam needed for the 150-ton absorption chiller. Since the combined capacity of the engine-driven and the steam-heated chillers totals 900 tons, the combined capacity of the new electric chillers needs to be only 1600 tons to meet the total chiller capacity need for 2500 tons.

Total capital cost for this chiller system Option 3.2 is estimated to be $1.55 million, including $0.80 million for the 1600 tons of electric chillers, and $0.75 million for the engine-driven chiller assuming $1000/ton installed cost for these chillers with heat recovery equipment.

The annual energy cost for operating this chiller option is estimated to total $61,600, including $0 for the annual demand charge (because no power is purchased), $52,600 for the electric energy from the fuel cell plant, and $9,000 for natural gas. Assuming an annual maintenance charge of $23/ton for the electric and the absorption chiller and $0.01/ton-hr more for the engine chiller than that for the electric chiller, total annual maintenance cost is estimated to be about $48,300. Therefore, the annual energy and maintenance costs for the hybrid chiller plant Option 3.1 are estimated to total $109,900.

The final selection of the preferred chiller system can be made by RIA after refining assumptions relating to the cooling load profile and its perspective of the impact of electric deregulation.

Environmental Impacts

Environmental Laws/Executive Orders

National Environmental Policy Act (NEPA)*

Since its enactment in 1971, NEPA has guaranteed that environmental impacts and associated public concerns are considered in decisions on Federal projects such as the installation of new power generation equipment on Federal proper-

* USEPA, EPA 4841, *National Environmental Policy Act Review Procedures for EPA Facilities* (May 1998).

ties. Generally, only Federal facilities are subject to NEPA requirements, however State and local agencies must adhere to these requirements when involved in Federal actions.

Many single, independent actions may not seem to greatly impact the surrounding environment quality; however performing a series of small, related actions may cumulatively and over time have significant effects. For all projects subject to NEPA requirements, cumulative effects must be taken into account during the scoping and reviewing processes.

NEPA's environmental scoping process encompasses not only environmental effects such as air quality, water quality, and waste disposal, but also includes aesthetic, historic, cultural, socioeconomic, and health impacts. For the fuel cell installation at RIA, environmental requirements that were deemed applicable are addressed in the following sections.

The NEPA review process is a three tiered progression, beginning with the Tier 1 Analyses that involve screening construction projects against categories of actions that normally do not require either an Environmental Assessment (EA) or an Environmental Impact Statement (EIS) are referred to as Categorical Exclusions (CX). (Refer to the NEPA Flow Diagram shown in Figure 31). Actions eligible under these categories have little or no effect on environmental quality and do not bring about significant changes to the existing environmental conditions. If the USEPA has granted the project a CX, it is exempt from any further environmental impact reviews.

For actions not meeting the requirements for a CX, an Environmental Assessment (EA - Tier 2 Analysis) is needed. The purpose of an EA is to determine if the proposed action may or may not significantly impact the environment. If the results of the EA review show that the project has no significant impacts, or that impacts can be mitigated, the USEPA will issue a "Finding of No Significant Impact" (FNSI). If an FNSI is issued, any mitigating measures that are needed to offset significant impacts must be addressed.

In contrast, if the EA determines that the action(s) pose significant environmental effects, an Environmental Impact Statement (EIS - Tier 3 Analysis) is necessary. An EIS provides a more detailed evaluation of the proposed action, mitigation opportunities, and alternatives that may reduce impacts. The EIS process is initiated with the development, distribution, and publication of a Notice of Intent (NOI) in the Federal Register (FR). In certain situations where the EPA foresees that an action may significantly impact the environment, a decision can be made to prepare an EIS without first developing an EA.

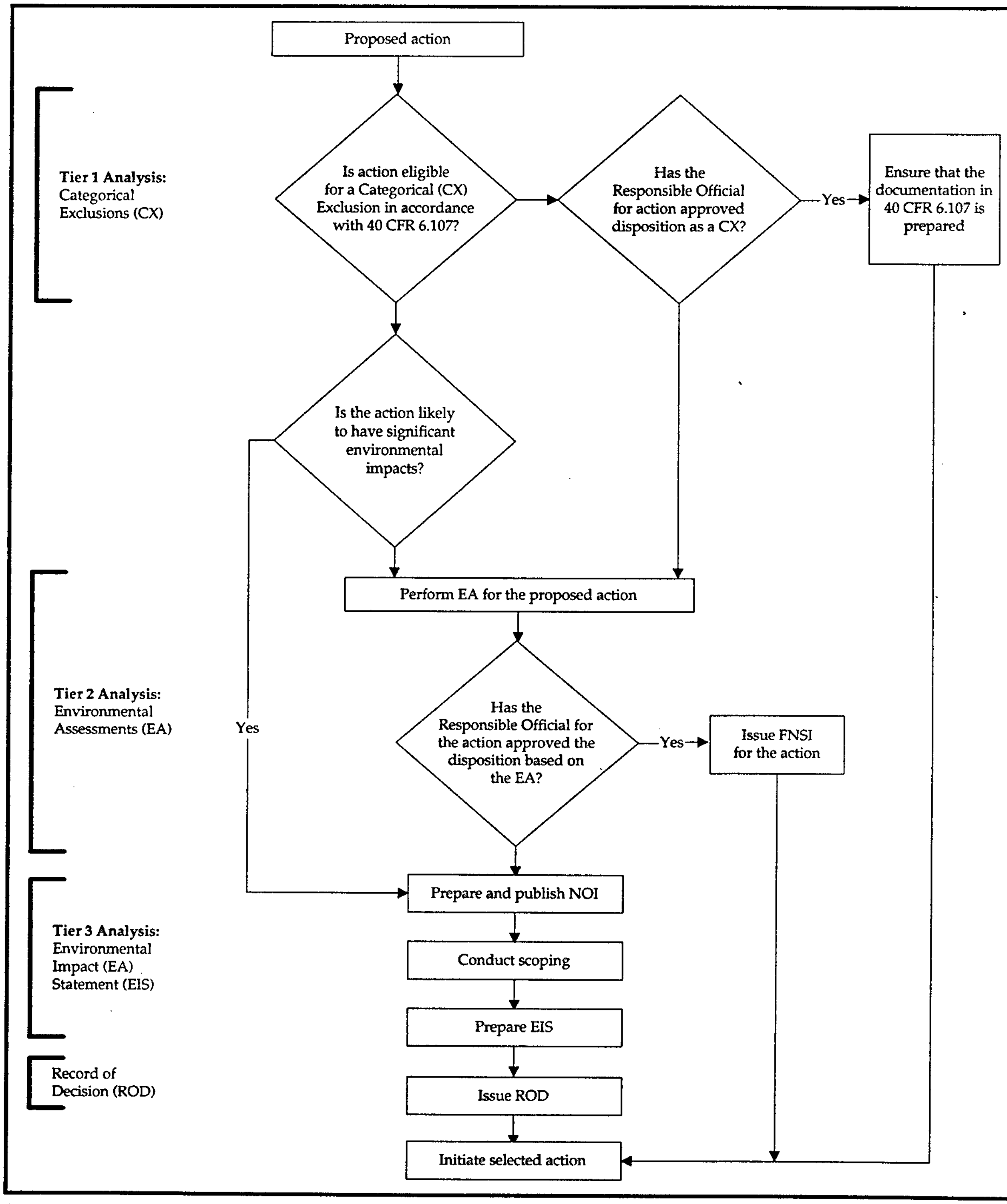


Figure 31. Overview of NEPA process.

After a Final Environmental Impact Statement (FEIS) is prepared and at the time of its decision, the USEPA must publish a Record of Decision (ROD), which addresses how the EIS findings, including consideration alternatives and mitigation measures were considered in the USEPA's decisionmaking process.

NEPA Compliance at RIA

Under NEPA guidelines, the siting of a fuel cell at a military base is not listed as a CX. Therefore, an EA will need to be prepared to determine if there are any significant environmental impacts associated with siting of the MCFC at RIA.

An EA was prepared for a 250 kW MCFC installation at the Marine Corp Air Station (MCAS) Miramar, CA, in 1996. In that case the USEPA issued an FNSI. Table 21 lists the documentation required in an EA report.

Applicable NEPA Requirements for MCFC Installation at RIA

After reviewing all possible environmental considerations under NEPA, a scope of environmental issues applicable to the MCFC installation at RIA was developed. Table 22 contains all possible environmental considerations under NEPA, laws that apply to each consideration, and a description of how applicable each consideration is to the installation of the MCFC at RIA.

Table 23 describes in detail applicable environmental laws and executive orders that apply to Federal facilities.

Table 21. Environmental assessment overview.

Purpose	Summarizes environmental impacts to determine need for: Further Study Mitigation measures.
Scope	Reviews all environmental impacts (e.g., natural and human impacts)
Content	Describes and identifies: Purpose and need for the proposed action Proposed action Alternatives considered (including the no action alternative) Affected environment (baseline conditions) Environmental consequences of the proposed action and alternatives Agencies and persons consulted.
Public Participation	EA is provided for review upon request or as an attachment to the FNSI.
Typical No. of Pages	10 to 50 of text and exhibits.

Table 22. Scope of environmental considerations.

Environmental Considerations	Environmental Laws	Applicability
Air Quality	Clean Air Act (CAA) of 1967, amended in 1990	Fuel Cell Emissions (NOx, SOx, NMHC, CO)
Water Quality	Clean Water Act (CWA) of 1972, amended in 1987	Effluent from Fuel Cell is introduced to RIA's wastewater system. RIA discharges to public treatment facility.
Health & Safety	OSHA 29CFR1910.5 - Occupational Noise Exposure / Noise Control Act / NFPA 50A – Standard for Gaseous Hydrogen Systems / State of IL 430 ILCS 75 – Boiler and Pressure Vessel Safety Act	Noise level of Fuel Cell is existent. Gaseous Hydrogen is contained within Fuel Cell. Steam Knock Out Drum contains high temperature and pressure steam.
Hazardous Materials & Waste	Toxic Substances Control Act / Hazardous Materials Transportation Act / Emergency Planning and Community Right- to-Know Act	N/A*
Geology & Soils	Not sure at this time what, if any, laws apply	N/A
Land Use	Farmland Protection Policy Act	N/A
Wetlands & Flood Plains	E.O. 11990 – Protection of Wetlands / E.O. 11988 – Floodplain Management.	N/A
Biological Resources	Coastal Zone Management Act / Coastal Barrier Resources Act / The Wilderness Act / Wild and Scenic Rivers Act / Fish & Wild Life Coordination Act	N/A
Endangered & Threatened Species	Endangered Species Act	N/A
Archaeological & Cultural Resources	Historic Sites Act / National Historic Preservation Act / Archaeological and Historic Preservation Act / E.O. 11593 – Protection and Enhancement of the Cultural Environment.	N/A
Socioeconomics	Not sure at this time what, if any, laws apply	N/A

* N/A – Environmental considerations do not apply.

Environmental Permitting/Safety Requirements

Air Permitting

The USEPA requires each state to develop a State Implementation Plan (SIP), which is a collection of regulations that explains how a State will maintain criteria pollutant levels below those specified in the National Ambient Air Quality Standards under the Clean Air Act. The states must involve the public in the approval process before a SIP is finalized. The USEPA approves each SIP, and if it is not acceptable, the USEPA can assume responsibility for enforcing the Clean Air Act in that State.

Table 23. Environmental statues and executive orders with which Federal facilities must comply.

Environmental Law/Executive Order	Federal Facility Responsibilities	Established Standards/Programs
Clean Air Act (CAA) of 1967, amended in 1990	• Obtaining necessary permits • Maintaining emissions within permitted levels • Complying with State Implementation Plan requirements • Ensuring that CFC technicians attend EPA-certified training courses • Ensuring that all CFC recovery/recycling equipment is certified to EPA standards and venting prohibitions are maintained • Managing facilities with asbestos-containing material (ACM) and conduction ACM removals in conformance with air toxics program requirements • Complying with applicable Federal controls on mobile sources and their fuel • Developing risk management plans where required • Maintaining all required records and documentation • Managing facility construction and modification	New Source Performance Standards (NSPS) – nationally uniform emission limitations for new or modified stationary emission sources. Based on industrial source type & availability of pollution control technology. Lowest Achievable Emission Rate (LAER) – case-by-case technology-based standard required for certain new or modified major stationary sources. Must be met in addition to NSPS and are implemented by permit. Reasonably Available Control Technology (RACT) - technology-based standard for existing sources usually developed on a source category basis. Best Available Control Technology (BACT) – New or modified sources in attainment areas where air is cleaner than NAAQS or in unclassifiable areas. Technology- based standard that is part of Prevention of Significant Deterioration of Air Quality (PSD). Title V – established an operating permit program for all major stationary sources of air pollution. NESHAPS – New and existing major sources of Hazardous Air Pollutants (HAPs) must comply with National Emission Standards for Hazardous Air Pollutants (NESHAPs).
State Enforcement of CAA	States have authority to adopt & implement measures to attain & maintain primary & secondary standards for each air quality region CAA ξ107 & ξ110 Federal facilities must comply with all Federal, State, interstate, and local requirements; administrative authorities; and processes and sanctions in the same manner and to the same extent as any nongovernmental entity.	

Environmental Law/Executive Order	Federal Facility Responsibilities	Established Standards/Programs
Clean Water Act (CWA) of 1972, amended in 1987	• Obtaining a National Pollutant Discharge Elimination System (NPDES) permit & managing direct discharges in compliance with permit conditions • Managing discharges to a Publicly-Owned Treatment Works in accordance with established Federal, State, and local pretreatment standards • Managing domestic treatment works in accordance w/ sludge requirements • Applying for ξ404 dredge and fill permits for construction & developments projects • Monitoring, recording, and reporting pollutant effluent concentrations • Develop, implement, and maintain stormwater pollution prevention plans & obtain necessary permits • Develop Still Prevention, Control, and Countermeasure Plans	National Pollutant Discharge Elimination System (NPDES)·Establishes effluent permit system for point source (e.g., pipe, ditch) discharges into navigable waters. Program requirements address permit applications, regulatory guidances, & management & treatment requirements (ξ402). National & Local Pretreatment Standards – Requires new and existing users to pretreat wastewater discharged to Publicly-Owned Treatment Works (POTW's) to prevent pollutants in excess of certain limits from passing though (ξ307). Federal Facilities that discharge to POTW's are excluded from NPDES permitting requirements, but are subject to national pretreatment standards (40 CFR Part 403), (40 CFR Parts 405-471), & any State or local standards.
Noise Control Act (NCA)0 1972, amended in 1978		
Executive Order (E.O.) 12088 – Federal Compliance With Pollution Control Standards	Requires all Federal agencies to be in compliance with environmental laws and fully cooperate with EPA, State, interstate, and local agencies to prevent, control and abate environmental pollution. Also requires Federal agencies to develop and maintain plans for controlling environmental pollution.	
Executive Order 12856	Federal facilities are required to comply with the provisions of the (EPCRA) and the Pollution Prevention Act (PPA). Mandates that federal facilities develop pollution prevention plans for reducing or eliminating the use of hazardous and toxic chemicals.	

Environmental Law/Executive Order	Federal Facility Responsibilities	Established Standards/Programs
Executive Order 12902	DOE is required to implement the energy and water efficiency goals and requirements through the Federal Energy Management Program.	The energy and water efficiency goals and reporting requirements for federal facilities include: Energy Consumption Reduction – develop and implement a program to reduce energy consumption by 30% by the year 2005; Energy and Water Surveys and Audits of Federal Facilities – w/in 18 months of the date of the E.O., agency must conduct a prioritization survey of facilities. Surveys will be used to establish priorities for conducting comprehensive facility audits and implement a 10-year plan to conduct or obtain comprehensive facility audits; Implementation of Energy Efficiency and Water Conservation Projects – w/in 1 year of E.O. must identify high-priority facilities to audit and must complete the first 10% of the required audits. W/in 180 days of the E.O. agencies must implement cost-effective recommendations from the audits performed in the last 3 years for installation of energy efficiency , water conservation, and renewable energy technologies; Minimization of Petroleum-Based Fuel Use in Federal Buildings and Facilities – must develop and implement programs to reduce the use of petroleum in their buildings and facilities and switch to a less polluting and non-petroleum-based energy source, such as natural gas or solar and other renewable energy sources; and Showcase Facilities –must showcase various buildings highlighting advanced technologies and practices for energy efficiency, water

Title 35 of Illinois' Administrative Code contains a list of emission sources that are exempt from air permitting. The exemptions are based on whether the emitting unit can meet an acceptable emissions level or heat input rate for that source type (e.g., gas turbine, IC engine). The air regulations are drafted in such a way that the air permitting requirements for the MCFC can only be speculated at this time. The actual requirements would be realized after installation of the unit. Although fuel cells are not specifically exempt and there is no general source exemption under Title 35, it can be argued that a 1 MW fuel cell should be exempt from air permitting requirements in the State of Illinois, given the following information: (1) the exemption level for a gas turbine under Title 35 is

10 MMBtu/hr (1 MW MCFC heat input rate is about 7 MMBtu/hr), and (2) fuel cells installed in the South Coast Air Quality Management District (SCQAMD) of California are exempt from permitting requirements pursuant to Rule 219 of SCQAMD regulations. SCQAMD enforces some of the most stringent air quality regulations in the nation. Table 24 lists the projected pollutant emission levels for the 1 MW MCFC.

Sewer/Wastewater Regulations

The central heating plant has a sewer connection in place to collect any blowdown from the boilers. As for the MCFC, any condensate that is captured in the Steam Knock-Out Drum during plant start-up or shutdown will have to be introduced into RIA's wastewater system. To capture the condensate outflow, the Steam Knock-Out Drum outflow will be interfaced with the existing sewer system. Siting the MCFC near the central heating plant will simplify this interconnection.

Pursuant to Army Regulations (AR 420-49, Chapter 4, Section 4-8), Army installations are subject to the following requirements:

1. All discharges from Army installations to publicly-owned treatment facility will comply with applicable pretreatment standards.
2. Federal Water Pollution Control Act of 1972 as amended by the Water Quality Act of 1987 states that wastewater treatment plant effluent will be treated to meet National Pollution Discharge Elimination System (NPDES) permit requirements.
3. Drains should not be used in close proximity to toxic or hazardous storage areas.
4. Periodic inspections should be made of non-domestic wastewater sources (e.g., laboratories, boiler plants, cooling towers).

Table 24. Projected pollutant emission levels for 1 MW MCFC.

Pollutant	Emission Level (ppmv)
NOx	<1.0
SOx	<0.01
CO	<5
CO_2	42,800
NMHC	<1.0

NOx – Reported as NO_2
SOx – Reported as SO_2
NMHC – Nonmethane Hydrocarbons reported as ethane

At this time, RIA discharges its wastewater to the City of RIA's treatment facility. The flow in prior years has been consistently around 1 million gal/day, but due to the shutdown of manufacturing processes and a decrease in base population, the current flow is around 300,000 gal/day. RIA has a wastewater collection system where all of the effluent is accumulated before being pumped to the public treatment facility. Before entering the collection system, the effluent from the Plating shop (Building 212), Painting area (Building 208), and Autocraft (Building 351) must be pretreated to remove contaminants that exceed acceptable water quality levels. The pretreated effluent is then introduced into the collection system along with other nondomestic as well as domestic wastewater produced in other buildings on the base. The condensate leaving the MCFC will merely contain small amounts of water conditioners, and the effluent is suitable for sanitary discharge.

For the City of RIA, the NPDES establishes an effluent permit system for point source (e.g., pipe, ditch) discharges into navigable waters. The RIA Army base is subject to these NPDES requirements. At times when the capacity of the public treatment facility is expected to be exceeded under the NPDES, the Arsenal is permitted to discharge directly into the Mississippi River. The amount of condensate outflow from the MCFC entering RIA's wastewater system will be insignificant.

Boiler Safety Codes

The proposed 1 MW MCFC is equipped with an unfired Single-Pass Boiler, which will be located in the Heat Recovery Steam Generator (HRSG). The HRSG is connected to the cathode outlet of the fuel cell stack. Thermal energy from the cathode exhaust gases will be used to heat the boiler feed water to superheated steam conditions, at 500 °F and 85.3 psig. After leaving the single-pass boiler, the superheated steam, which is required in the natural gas reformation process, enters the Steam Knock-Out Drum, where any saturated liquid in the steam flow that may occur during plant start-up or shutdown is removed. The Steam Drum's functionality is of a pressure vessel and not a boiler.

Although all Federal boiler installations within the State of Illinois are exempt from the "Boiler and Pressure Vessel Safety Act (430 ILCS 75)," RIA subjects themselves to both Federal and State boiler and pressure vessel safety codes. They will adhere to whichever set of regulations is more stringent. Army regulation (AR 420-49, Section 6-3), regarding boiler and heating plants, does not reference or have safety standards for pressure vessels. For an MCFC installation, the Boiler and Pressure Vessel Safety Act is more applicable to the fuel cell's steam production system. Under the Boiler and Pressure Vessel Safety Act, the Steam Drum, which has a volume equal to 2260 cu ft, is subject to certification pursuant 430 ILCS 75/11 and inspection as to its construction, installation, condition, and operation pursuant to 430 ILCS 75/10.

Under the Boiler and Pressure Vessel Safety Act, an operator must be designated to oversee the operation of the Steam Drum, as well as maintain and perform recordkeeping duties pursuant to section 120.500 of this code.

Hydrogen Storage

Gaseous hydrogen is one of the primary fuels needed for the electrochemical reactions to occur in the fuel cell stack. The hydrogen is produced during the natural gas reformation process. As hydrogen is being used up in the electrochemical reaction, more is being generated in the reformer. In this way, the MCFC can be seen as a single dynamic storage system for the hydrogen gas. The maximum volume of hydrogen within the entire fuel cell plant at full capacity is estimated to be 20 to 25 standard cubic feet (SCF).

Under the NFPA 50A Standard for Gaseous Hydrogen Systems at Consumer Sites, 1994 Edition, Section 1-1.5, the fuel cell hydrogen storage system is exempt from any design construction or testing protocol based on the following condition: This standard shall not apply to single systems using containers having a total hydrogen content of less than 400 SCF.

National Fuel Gas Codes

NFPA 54, National Fuel Gas Code for installation of gas-fueled generators will be followed for this installation. This would include any pressure regulation, gas line shutoff, cathodic protection, and metering. NFPA 853, which specifically covers fuel cell installations, is under development and review. If it is available during site engineering, it should be followed.

Noise Exposure

The noise level of the MCFC reported as 60 dB at a distance of 100 ft from the source (California Energy Commission 1997). As required by 29 CFR 1910.95, this measured noise level is below the allowable 8-hour threshold of 90 dB.

Table 25 lists permissible noise exposure levels that are in accordance with Office of Safety and Health Administration (OSHA) Regulations, 29 CFR 1910.95 – Occupational Noise Exposure.

Table 25. Permissible noise exposures.

Duration per Day, hrs	Sound Level dBA Slow Response
8	90
6	92
4	95
3	97
2	100
1.5	102
1	105
0.5	110
0.25 or less	115

According to Section (b)(1) of this rule:

> When employees are subjected to sound exceeding those limits listed in Table 25 feasible administrative or engineering controls shall be used. If such controls fail to reduce the sound levels within the levels of Table 25, personal protective equipment shall be provided and used to reduce sound levels with the levels of the table.

Environmental Benefits

Environmental benefits as a result of the MCFC installation will be realized through offsetting emissions from both the utility power plants that provide electrical power to RIA and the coal burning central heating plant, which produces steam for space heating throughout the base as well as providing steam for various manufacturing processes.

Currently, MidAmerican Energy Co, residing in Iowa, supplies RIA with their electrical power. However, realistically speaking, given that the individual electrical power distribution/transmission lines in each state are actually interconnected so as to reflect one contiguous system, it is impossible to pinpoint the exact origin of the electrical power that reaches RIA's internal distribution system. The electric utilities within Illinois and the surrounding regions use a power generation mix that includes several different fuel sources: coal, oil, natural gas, nuclear, and hydroelectric.

Moreover, the percentage make-up of each fuel type (e.g., % coal, % oil, % natural gas) that is used to produce the power for any one electric utility customer can vary greatly depending on how confined or specific the scope for the region in question is. With the understanding of this concept and for the purposes of this report, the electrical power generation mix for RIA is based on a regional average as opposed to just looking at the State of Illinois. Table 26 contains a regional average power generation mix and emission factors (SO_2, NO_2, CO_2) for Illinois, Indiana, Ohio, and Michigan (Environmental Defense Fund website).

Currently, the central heating plant burns Eastern Kentucky coal, a bituminous coal, which has a sulfur content of 1.3 percent by weight and an energy content of 12,094 Btu/lb. Emission factors for each of the 4 boilers were taken from USEPA's AP-42. In most cases, these factors are simply averages of all available data of acceptable quality, and are generally assumed to be representative of long-term averages for all facilities in the source category (i.e., a population average). According to AP-42, on average for bituminous coal, 95 percent of the fuel sulfur is emitted as SO_2. This translates to 1.24 percent of the sulfur will be emitted as SO_2.

The MCFC is expected to supply 1 MW of electricity to the central heating plant and will operate at full capacity for 7,884 hr/yr (assuming 90 percent capacity factor). This additional electrical power generated by the MCFC will replace the grid power that is currently being used to power electrical equipment within the central plant. The fuel cell's cogeneration capability allows it to capture and use the waste thermal energy produced during the electrochemical reactions in the fuel cell stack. This additional thermal energy will ultimately provide additional steam, which will supplement a portion of steam plant's load.

Table 27 lists the estimated emissions reductions due to displaced electricity production and heat recovery. Although fuel cell emissions are minimal in comparison, they have been accounted for in determining the emissions reduction for the entire project. The fuel cell emissions are given in parentheses to denote a source as oppose to a reduction in emissions.

Table 26. Emission factors for electric utility power plant, central heating plant boilers, and MCFC.

Emission Type	Electric Utility (lb/MWh)	Heating Plant Boilers (lb/MMBtu)*	MCFC (lb/MWh)
SOx	17.4	1.90	0.0003
NOx	8.7	0.42	0.023
CO_2	1,713	180.2	930
CO	**	1.90	0.07

* SOx, NOx and CO are averages from actual RIA heating plant emissions tests (source: EMT Report 98-509). CO_2 are estimated from EPA coal plant emissions.

**No available data on CO emission factors for electric utilities in this region.

Table 27. Net electric power generation and heat recovery emissions reductions (tons per year).

Emission Type	Electric Utility (TPY)	Heat Recovery (TPY)	MCFC (TPY)	Total Avoided Emissions (TPY)
SOx	68.6	11.5	0.0	80.1
NOx	34.3	2.5	0.1	36.7
CO_2	6,752.6	1,088.4	3,666.1	4175.0
CO	-	11.5	0.3	11.2*
*Does not include CO emissions reductions from bulk electric power supply.				

According to these findings, based on the amount of electrical and thermal power generated by the 1 MW plant, the installation of the fuel cell at RIA would result in a significant reduction in pollutant emissions from the steam plant and respective utility power generators. Carbon dioxide (CO_2), listed as one of the greenhouse gases, would show a 4,175 tons per year (TPY) reduction, the largest decrease in emissions. Additionally the fuel cell will achieve significant reductions in SOx and NOx, which are major contributors to acid rain and photochemical smog.

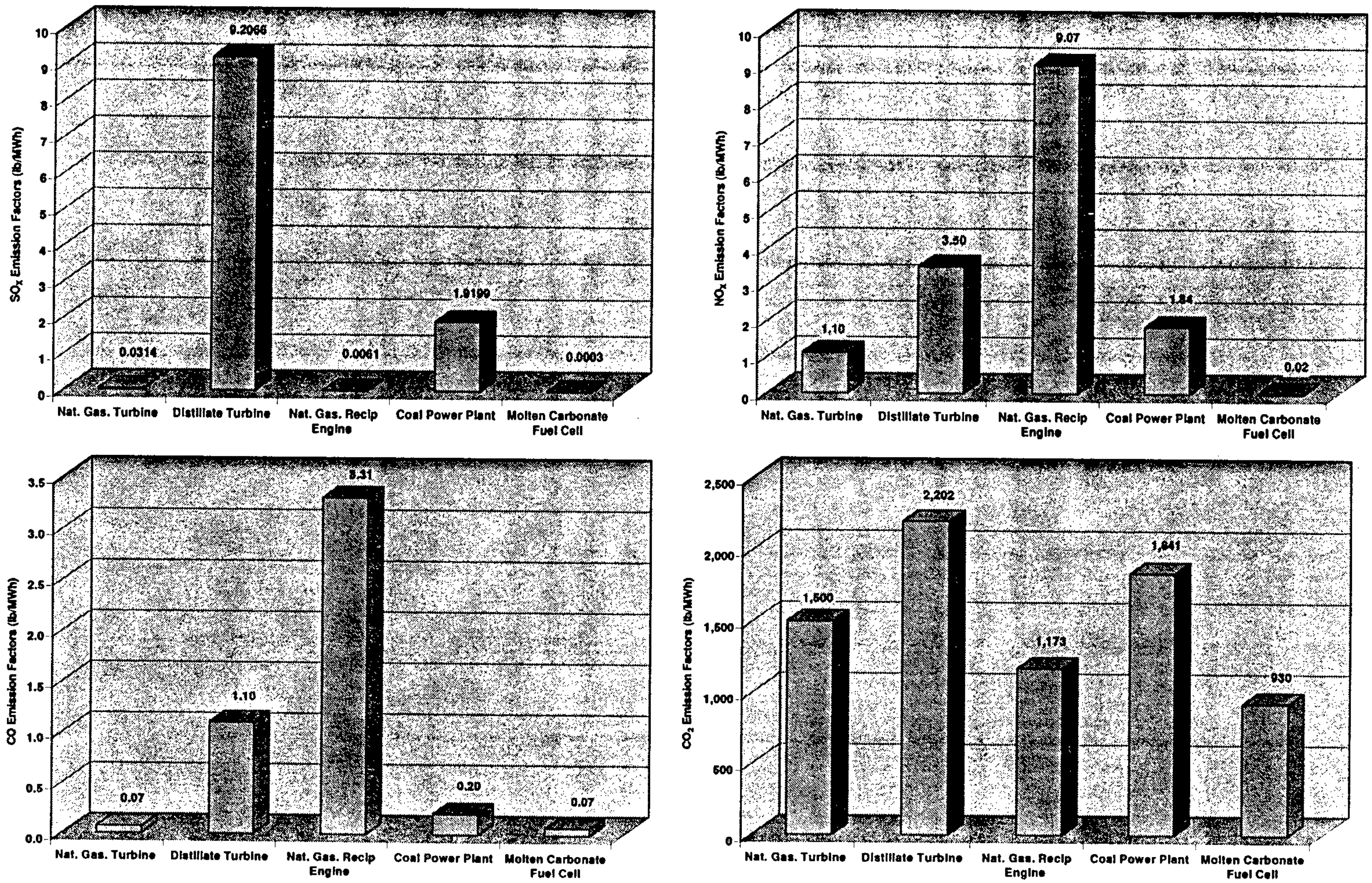
The MCFC power plant is an ultra-low air emission electric generator. Figure 32 shows the MCFC power plant emissions (lb/MWh) in relation to emissions produced by other technologies. The fuel cell compares very favorably with other generating technologies for NOx, SOx, and CO emissions. The fuel cell plant's high efficiency enables it to produce less CO_2 emissions than other power plants.

Energy Conservation Opportunities at Building 212

Steam Usage for Space Heating (Building 212)

Building 212 uses steam at 35 psig to heat ventilation air. The ventilation air flow rate for the building is approximately 500,000 cfm. Figure 33 shows the data for space heating obtained from RIA.

The data in Figure 25 indicates that steam usage for heating is near zero during the summer months. During the winter, the usage is usually around 15,000 lb/hr. There is a 2-week spike in the steam consumption during which steam usage rose as high as 45,000 lb/hr. Researchers were not able to determine the cause for this spike in usage. A data collection error is possible since the data are based on manual meter readings.



Assumptions: Base emission factors (lb/MMBtu) from EPA AP42. Natural gas fueled gas turbine is a 1 MW unit, lean burn with a heat rate of 13,910 Btu/kWh. Distillate fueled gas turbine has water injection and a heat rate of 13,910 Btu/kWh. Natural gas recip is a 1 MW lean burn with SCR and a heat rate of 10,881 Btu/kWh. Coal plant is assumed to be a pulverized coal tangentially fired plant burning a blend of Kentucky and Illinois bituminous coal.

Figure 32. Molten carbonate fuel cell emissions.

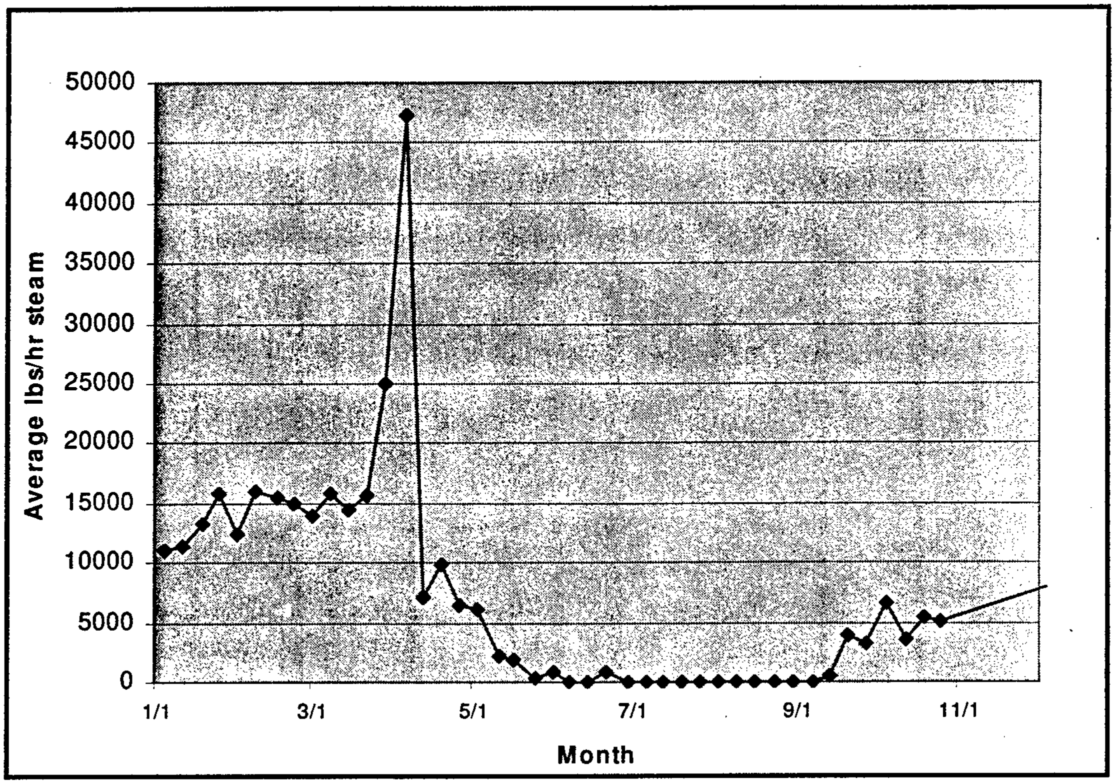


Figure 33. Average hourly space heating steam usage.

Steam usage for heating at Building 212 could be significantly reduced through the application of heat recovery to the ventilation system. The large outside air requirements provide an opportunity to exchange heat between the exhaust and inlet air streams. Depending on the location of air intakes and exhaust, it may be possible to use a direct air-to-air heat exchanger, or it may be necessary to use heat pipe or run-around loop systems. Assuming sensible heat recovery only and a 67 percent heat recovery efficiency, energy savings on the order of 10 MMBtu/hr are possible. Based on the data shown in Figure 25, seasonal savings on the order of 31,700 MMBtu may be achievable.

An alternative opportunity for energy savings may exist through the replacement of steam pressure reducing valves with backpressure steam turbines to generate electric power. Presently, 15,000 lb/hr of steam are supplied to Building 212 at 135 psig and are used for heating at 35 psig. Assuming a turbine efficiency of 51 percent, it is possible to generate about 183 kW. Based on heating season usage, seasonal energy savings on the order of 584,000 kWh may be possible. Cost for electricity generated using the backpressure turbines will be approximately \$9.00 per MWh compared to an average winter purchased electricity cost of \$37 per MWh.

A review of data provided by RIA for all steam pressure reducing valves at the Arsenal suggests that there may be several points in the steam distribution system where backpressure turbines could be installed in place of steam pressure reducing valves to generate electric power.

Building 212 Steam Usage for Plating

The Building 212 plating shop uses steam at 15 and 35 psig (250 and 280 °F) for heating plating baths. There are 120 plating tanks, about half of which are heated. Some tanks have panel coil heat exchangers while others use shell and tube heat exchangers.

Chrome-plating operations use 18, 1200 gal plating tanks, which are each heated and cooled using a dual usage shell and tube heat exchanger. During the heating cycle, the tank contents are raised from ambient temperature to 140 °F over a 3-hour period. The estimated energy consumption is about 847,000 Btu plus tank heat losses, or about 282,300 Btu/hr plus losses. If all the chrome-plating tanks operated simultaneously, energy consumption would be about 5,090,000 Btu/hr plus losses.

Use of fuel cell heat recovery output of 1.18 MMBtu/hr to provide heating for chrome plating operations would represent an energy savings of approximately 23 percent.

Data obtained from RIA suggest that steam usage for plating operations at Building 212 is presently very low. Figure 35 shows weekly steam usage for plating operations in Building 212.

Variable Speed Drives for Air Handling Fans (Fundamentals)

Controlling motor speed to correspond to load requirements provides many benefits, including increased energy efficiency and improved power factor. For cube-law loads (such as fans), reducing motor speed can significantly reduce energy consumption.

What load the motor shaft is connected to is critical in determining cube-law applicability. In general, the cube law applies only to loads in which required torque increases with speed because of fluid friction.

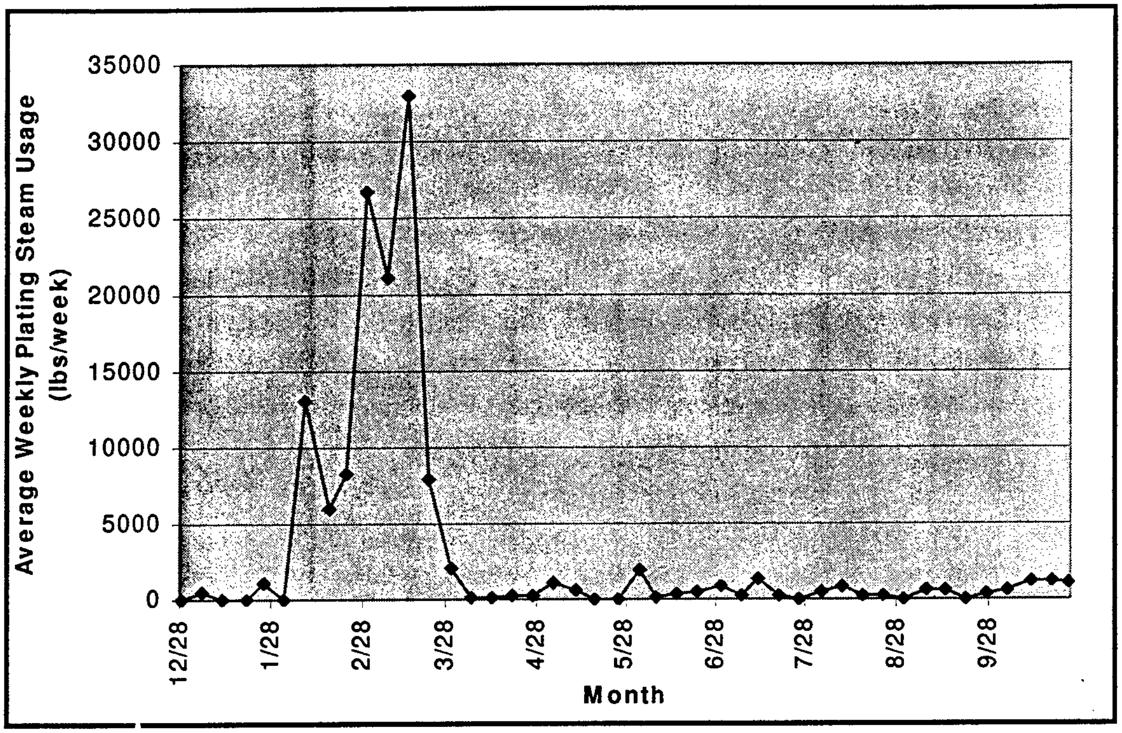


Figure 34. Building 212 steam usage for plating.

Consider a fan moving air through a simple duct loop. The fan is essentially doing no physical work other than overcoming the friction of the duct loop, so the power to drive the fan is the product of the fan efficiency times flow times pressure (times a constant, to make units consistent). Assuming that fan efficiency is nearly the same at all speeds, fan power is proportional to flow times pressure. It turns out that both of these variables depend on the speed of the fan. Flow is proportional to speed (double the speed, double the flow). Pressure, however, is proportional to speed squared (double the speed, quadruple the pressure) because it is controlled by friction, which increases as air moves faster.

Combining these relationships shows that fan power is proportional to speed times speed squared, or speed cubed. This relationship generally applies to all types of fluid friction in ducts and piping systems.

Application at Building 212

At Building 212, air-handling units containing steam coils are used during the winter to temper the building air. During the summer months, the fans in the air handling units operate to provide some cooling and mixing of the air in the building.

The motors in the larger air handling units range from 10 to 60 HP. The equipment record for the Arsenal indicates the following air handling motors in Building 212:

- 4 – 10 HP
- 2 – 15 HP
- 1 – 20 HP
- 15 – 25 HP
- 3 – 40 HP
- 4 – 60 HP.

All are three-phase, 460 V motors. Most operate at 1760 RPM, however the 60 HP motors are listed at 633 RPM and four have no operating speed listed.

Arsenal personnel indicate that the air handling fans operate throughout the year. The fans, however, seasonally operate at different speeds through the use of two-speed motors. During the heating season, the motors operate on low speed, and during the summer season, the motors operate on high speed.

The use of two-speed fan operation saves significant energy. The energy required by the fan varies as the cube of the speed. Therefore, reducing the speed by half reduces the energy to one-eighth of high-speed operation. This operation negates much of the energy savings available through the use of variable speed drives.

The Users Guide for the "Adjustable Speed Drive Evaluation Methodology and Applications Software" published by the Electric Power Research Institute states that potential applications should be screened for several factors: (1) variability of load, (2) motor size, and (3) total operating hours. Motors smaller than 75 HP are only fair applications, and motors operating less than 6000 hr/yr are only fair applications. With the Building 212 motors operating at low speed for the winter season, the equivalent annual operating hours would be reduced below 6000 hours.

Based on motor sizes below 75 HP, the low equivalent annual operating hours, and the low energy price at the Arsenal, it is unlikely that ASDs would offer acceptable payback based on energy savings alone.

Summary of Building 212 Energy Conservation Options

Table 28 lists potential energy savings for Building 212.

Table 28. Summary of Building 212 energy conservation options.

Option	Estimated Annual Energy Savings
Ventilation air heat recovery	31,700 MMBtu
Application of back-pressure turbines	584,000 kWh
Ventilation fan adjustable speed drive	Negligible

Fuel Cell Interactions with Geothermal Heat Pump Systems

Rock Island Arsenal is beginning a study to evaluate the feasibility of retiring the central steam plant and replacing it with geothermal heat pumps and packaged boilers. This section of the report examines some of the impacts of the heat pumps on the base electrical load and on the proposed fuel cell installation.

Geothermal Heat Pump Technology

Geothermal heat pumps use solar energy stored in the upper portion of the earth's crust as a source of energy to provide heating during the winter. During the winter, the heat pump extracts heat from the soil and uses it to heat the load. The operation of the heat pump along with soil heat losses to the air during the winter provides a heat sink for use during the summer cooling season. During the summer, the heat pump extracts heat from the load and rejects it to the soil.

Geothermal heat pumps are electrically driven and typically operate with a coefficient of performance (COP) in heating mode of between 4 and 5. This means that between 75 and 80 percent of the heating load is met by solar energy stored in the soil; the remainder is provided by electricity. Assuming a 3:1 ratio of primary energy to delivered electrical energy, and a fossil fuel heating system efficiency of 80 percent indicates that the geothermal heat pump system can save between 40 and 50 percent of the energy used by a conventional heating system.

In cooling mode, the heat pump rejects heat to the soil rather than to the air so that the heat rejection temperature is significantly reduced. Conventional rooftop air-conditioners using air-cooled condensers operate at COPs between 2 and 3 while the heat pump in cooling mode will operate at a COP of about 4. This results in the potential for between a 25 and 50 percent savings in electrical energy.

Life expectancy of geothermal heat pump systems is approximately the same as conventional systems, between 20 and 25 years.

Installed costs for geothermal heat pump systems vary considerably due to site conditions, system designs, experience of designers and installers, and the geothermal heat pump technology infrastructure within a particular area. Installed cost premiums may range from zero (equal to cost of conventional system) to \$3,000/ton. Payback periods of 3 to 8 years may be expected under favorable conditions.

Impacts on the Fuel Cell Installation

Application of geothermal heat pumps at RIA will impact one of the fuel cell heat recovery options. Application of the heat pumps will also increase the overall RIA electrical demand and thus improve the value of the fuel cell electrical power output.

Impacts on Heat Recovery

This study proposes two possible options for recovering waste heat from the fuel cell. One of the options, which would use fuel cell waste heat to preheat central plant boiler make-up water, would become unfeasible if the central plant were to be retired. However, if a packaged boiler for process steam were to be installed in a building near the fuel cell site, the fuel cell could be used to preheat make-up water for this boiler. Use of fuel cell waste heat in any case should result in a small savings in operating costs for the purchase of packaged boilers. Note that the use of natural gas fueled packaged boilers will increase the value of fuel cell waste heat recovery, due to the higher cost of gas relative to coal.

Impacts on Electrical Usage

Phase I of this study indicated that central plant average steam output during the heating season is approximately 100,000 lb/hr. Presently, with the low level of manufacturing activity, the majority of this steam is used to heat buildings. Assuming 70,000 lb/hr are currently used for building heating, and assuming a geothermal heat pump COP of 4.5 results in an average increase in heating season electrical demand due to heat pump application of about 4.6 MW. About 1.2 MW of this increase will be offset by the retirement of the central plant, leaving a net increase of about 3.4 MW.

During the cooling season, central plant steam output is about 30,000 lb/hr, the majority of which is currently used to drive absorption chillers. Data from RIA (Table 29) indicates the following cooling capacities.

Table 29. Cooling equipment installed tonnage at RIA.

System Type	Installed Tons
Chillers	
Absorption chillers	2,489
Air cooled chillers	1,605
Water cooled chillers	630
Roof-top/Air cooled DX Type	
Air cooled condensing units	1,384
Air dryers	580
Computer room air conditioning	984
Total roof-top/DX	2,948
Window air-conditioners	347

Table 30. Estimated impact of heat pumps on cooling season electric loads.

Existing Cooling Systems	Tons	kW/ton	MW
Roof-top DX types	2,948	1.76	5.2
Absorption chillers	2,489	≈ 0	0.0
Air cooled chillers	1,605	0.9	1.4
Water cooled chillers	630	0.7	0.4
Total	7,672		7.0
Case 1:Replace all with geothermal heat pump systems			
Heat pump systems	7,672	1.4	10.7
Case 2: Replace roof-top DX with heat pumps, replace absorption with water cooled centrifugal			
Heat pump systems	2,948	1.4	4.1
Air cooled chillers	1,605	0.9	1.4
Water cooled chillers	3,119	0.7	2.2
Total	7,672		7.7

The impacts on RIA cooling season electrical demand due to application of geothermal heat pumps are estimated below for two cases. In both cases, it is assumed that window air-conditioners will not be replaced (and are therefore not included in the analysis). Table 30 shows that, in Case 1, where all cooling systems are replaced with geothermal heat pumps, there will be an estimated net increase in summer electric demand of 3.7 MW. Installation of the fuel cell would reduce this increase to 2.7 MW.

In Case 2, where only rooftop DX systems are replaced by the heat pumps and absorption chillers are replaced with water cooled centrifugal chillers, the net increase in summer electric demand is only 0.7 MW, which can be completely offset by installation of the fuel cell.

Summary

Phase II of this feasibility study has identified a location for the fuel cell at RIA near the central heating plant, and determined the most likely locations for interface of the fuel cell with base utilities. Preliminary details of the electrical and thermal interface have been provided. No unusual problems or circumstances were identified related to the fuel cell installation.

Analysis indicates that the application of the fuel cell at RIA will result in electric energy reductions of about 9 percent and electric demand reductions of about 5 percent. Key to these electric energy and demand purchase reductions is baseloaded operation of the fuel cell power plant without reducing the inexpensive hydroelectric power generated within the Arsenal. Our analysis has indicated that the minimum purchased electricity demand of the Arsenal is 4 MW. Therefore, the baseload operation of the 1 MW fuel cell is anticipated to be feasible and will not result in any turndown of the hydroelectric production.

Heat recovery from the fuel cell is projected to reduce summer coal consumption by about 3 percent and winter coal consumption by about 1.5 percent.

Monthly economic benefits from the fuel cell are nearly $11,000 per month during the summer and about $5,000 per month during the winter. This results in an annual benefit to RIA of $84,580.

Analysis of the fuel cell as standby power for the central heating plant suggests that motor inrush loads will not exceed the 1 MW fuel cell output capacity. It appears then, that with adequate planning and careful load management, the fuel cell is capable of cold-starting the RIA central plant No. 3 boiler.

In the event the fuel cell is not operating during an electrical power interruption, it can be "black" started, if this is required. The fuel cell turbo-generator can use natural gas at pipeline pressure (20 psig minimum) to direct fire the turbine. The compressor-side of the turbo-generator will exhaust through a waste gate. Once the turbo-generator has powered the control system and gas booster, a normal start sequence can be initiated.

Under NEPA guidelines, the siting of a fuel cell at a military base is not listed as a CX. Therefore, an EA will need to be prepared to determine if there are any significant environmental impacts associated with siting of the MCFC at RIA.

Although fuel cells are not specifically exempt and there is not a general source exemption under Title 35, it can be argued that a 1 MW fuel cell should be exempt from air permitting requirements in the State of Illinois.

Accordingly, based on the amount of electrical and thermal power generated by the 1 MW plant, the installation of the fuel cell at RIA would result in a significant reduction in pollutant emissions from the steam plant and respective utility power generators. Carbon dioxide (CO_2), listed as one of the greenhouse gases, will be reduced by 4,175 TPY, the largest decrease in emissions. Additionally, the fuel cell will achieve significant reductions in SOx (80 TPY) and NOx, (37 TPY), major contributors to acid rain and photochemical smog.

Evaluation of possible impacts of changes in installation energy consumption profiles due to implementation of geothermal heat pumps suggests that the fuel cell benefits are not diminished by heat pump application. In fact, increases in electrical energy demand that may occur due to heat pump application tend to increase the benefits of installation of the fuel cell.

4 Phase III

Model Description

Model Method Selection

In preparation for this phase of the siting project, researchers reviewed a number of energy system modeling techniques and determined that there are four different modeling methods appropriate for this project (cf. Appendix D).

1. **Hour-by-Hour Simulation**
   In this method, the user develops, through parameter definitions, heat transfer and thermodynamic energy balance equations for components within an energy system. More sophisticated versions of this method can model the energy systems dynamic behavior by solving the set of linear differential equations that fully describe the systems characteristics. Hour-by-hour energy simulations include BLAST* and DOE-2,† which are used to model building facility energy consumption. These hourly, whole-building energy analysis programs calculate energy performance and life-cycle cost of operation. Program users analyze energy efficiency of given designs or efficiency of new technologies. Other uses include utility demand-side management and rebate programs, development and implementation of energy efficiency standards and compliance certification, and training in architecture and engineering schools.
2. **Bin Method Modeling**
   This energy modeling technique consists of performing an instantaneous energy balance calculation at many different outdoor temperatures conditions, and multiplying the results by the number of hours of occurrence at each temperature condition. Many consider this method simple but less accurate than performing an hour-by-hour simulation. The modeling technique also makes it difficult to capture certain time dependent characteristics. The bin method was popularized

* Summary of BLAST features may be found at the DOE website http://www.eren.doe.gov/buildings/tools_directory/software/blast.htm

† Summary of DOE-2 features may be found at the DOE website http://www.eren.doe.gov/buildings/tools_directory/software/doe-2.htm

by research performed by ASHRAE (Kneble 1983). The bin method has been implemented in a number of energy system evaluation software. One of the more popular versions is ASEAM (A Simple Energy Analysis Model).*

3. **Lumped Period Deterministic Modeling**
   This modeling technique consists of lumping energy production, consumption and pricing into periods of time that are larger than hour-by-hour simulation time steps. Typically these periods are months or years. The modeler balances energy consumption with on-site and utility-provided energy supply. Energy consumption modeling is accomplished by developing mathematical correlations with historical weather or pattern use such as time-of-day or day-of-week. This method is popular when using historical utility billing or submeter data. Most models of this, even when complex, are easily implemented using computer spreadsheet programs.
4. **Lumped Period Stochastic Modeling**
   This is an extension of lumped period deterministic modeling where inputs are defined and results are forecast as bounded probability distributions. The ability of this method to account for input uncertainty is a key element in producing realistic forecasts. This method is very attractive as a decision analysis tool because the forecasts are provided as probability curves. Thus the relationship between uncertainty and decision performance can be appreciated and accounted for when making critical decisions such as project investment.

AESC evaluated each of these methods as an approach for modeling the impacts of the MCFC installation at RIA. Because the proposed MCFC installation would serve the RIA thermal and electric network and not a dedicated load such as a single building, it would be difficult to develop a DOE-2 type of analysis unless each building was included. In addition, review of historical energy consumption data in Phase II revealed some uncertainty with energy loads, especially with those associated with process thermal requirements.

Because of the characteristics of the project, AESC selected the Lumped Period Stochastic Modeling method as the approach for the MCFC installation at RIA. A general overview of stochastic modeling is provided for the readers' convenience in Appendix E.

* Summary of ASEAM features may be found at the DOE website http://www.eren.doe.gov/buildings/tools_directory/software/aseam.htm

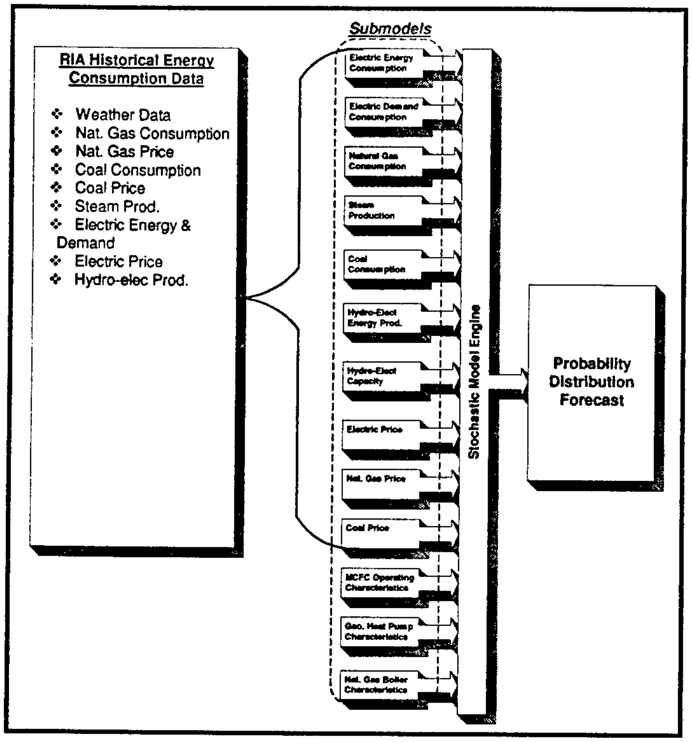


Figure 35. General model configuration.

Overall Model Configuration

The stochastic model developed for the RIA MCFC analysis consists of submodels. Most of these submodels are derived from historical energy consumption, production, and price data provided by RIA and summarized in Appendix E. The parameters of the MCFC power plant and other equipment (e.g., geothermal heat pump and natural gas fuel boiler) are encapsulated as submodels to maintain program organization. Figure 35 shows an overall illustration of the model.

As shown, three of the submodels are equipment characteristics. Equipment characteristics may consist of constant values or distributions depending on the nature of the parameters. The remaining submodels were derived from RIA's historical energy data. These submodels consist of mathematical regression and distribution formulas developed from the historical data. Appendixes F and G summarize the stochastic modeling results for the probability distributions for all of the applicable model assumptions.

The model results are expressed as energy cost savings with and without the fuel cell power plant. Thus the cost savings resulting from the fuel cells installation and operation can be readily determined.

Two separate models were developed, one that assumes that the Central Steam Heating Plant will remain in operation, and a second model that assumes that the Central Heat Plant is fully retired. The second scenario assumed that process steam loads are supplied by natural gas fuel boilers and that space heating loads are supplied by geothermal heat pumps.

Submodel Descriptions

Individual submodels were developed and linked within an Excel spreadsheet using the Crystal Ball 4.0 stochastic engine. Submodels are divided into energy balance and equipment specifications. The following sections provide below detailed descriptions of each submodel.

Electric Load and Price

RIA electricity is supplied from MidAmerican Energy at high voltage and is metered at the MidAmerican Energy substation No. 53 located at the southwest region of the Arsenal. Electricity from MidAmerican is delivered to the Arsenal's various facilities through RIA's electric distribution grid. In addition to electricity supplied by MidAmerican, RIA operates a hydroelectric power plant that augments the bulk power purchases.

Figure 36 shows that RIA's electric energy load is slightly correlated with average monthly ambient temperature indicating some air-conditioning load. The majority of the electric energy consumption appears to be made up of business and process equipment loads. There is significant variance about the fitted linear equation.

Equation 1 describes the submodel equation developed for RIA's electric energy consumption.:

$$E_{electric} = (\alpha T_{amb} + \beta)(1 + \rho) \quad \text{[Eq 1]}$$

Where: α = 23.412
β = 6,787.6
ρ = uncertainty factor.

The "uncertainty factor" is a probability distribution developed from the actual variance between the historical and linear equation. Because of the nature of the model being implemented, it is relatively straightforward to simulate this uncertainty by supplying this factor. Many of the model equations use an uncertainty term.

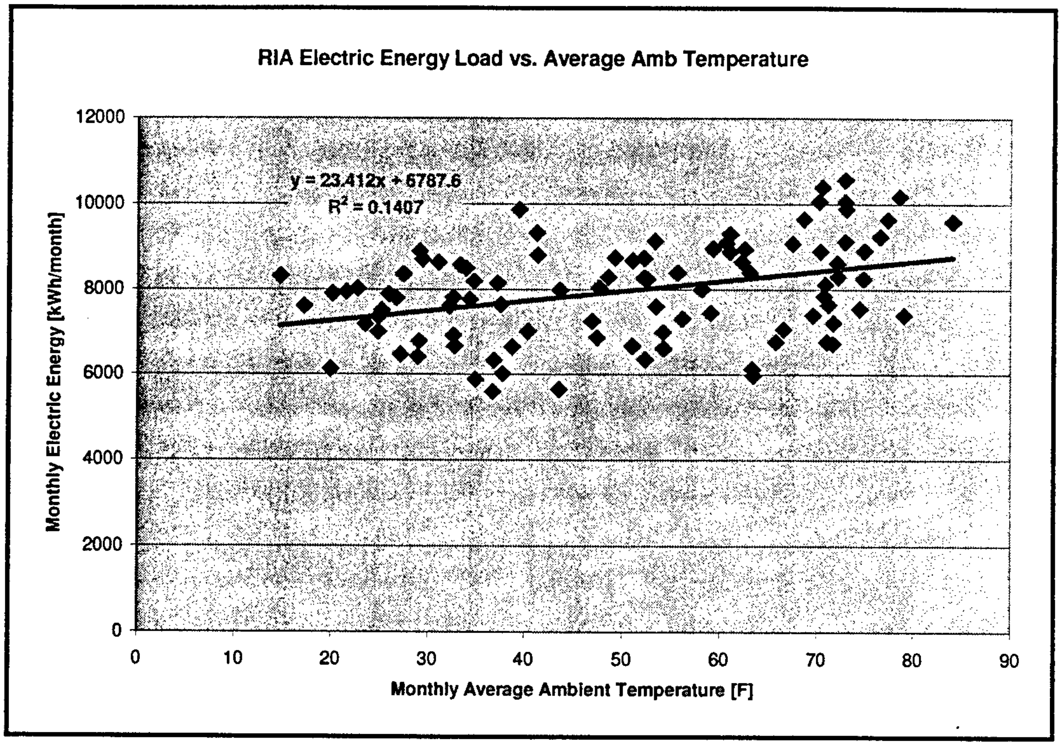


Figure 36. RIA electric energy correlation.

Peak monthly electric demand was also determined to be loosely correlated with average monthly ambient temperature. Figure 37 shows the relationship of peak demand and average temperature.

Similar to RIA's electric energy model, an equation was developed that included an uncertainty term so that the peak electric demand could be modeled.

Key to determining the amount of electricity purchased is the establishment of a submodel of hydroelectric production. Unlike electric load, hydroelectric generation is more closely correlated with the water level (head) that is held by the dam. Figure 38 shows that this relationship is best captured in three piecewise linear equations.

Average monthly head was found to be seasonally dependent. During certain months, it was typically lower and others it would be higher. Fairly high uncertainty was found at all months. Figure 39 illustrates the monthly variation of the hydroelectric power plant head.

Triangular probability distributions into the model was developed and implemented using these variations.

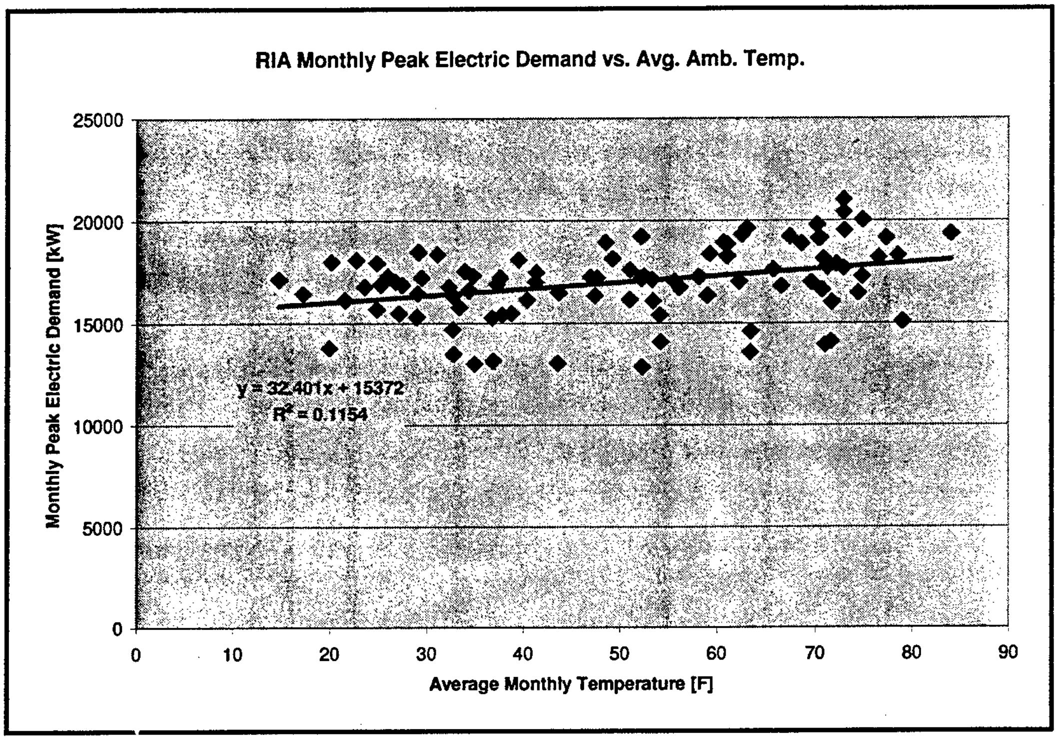


Figure 37. RIA monthly peak electric demand correlation.

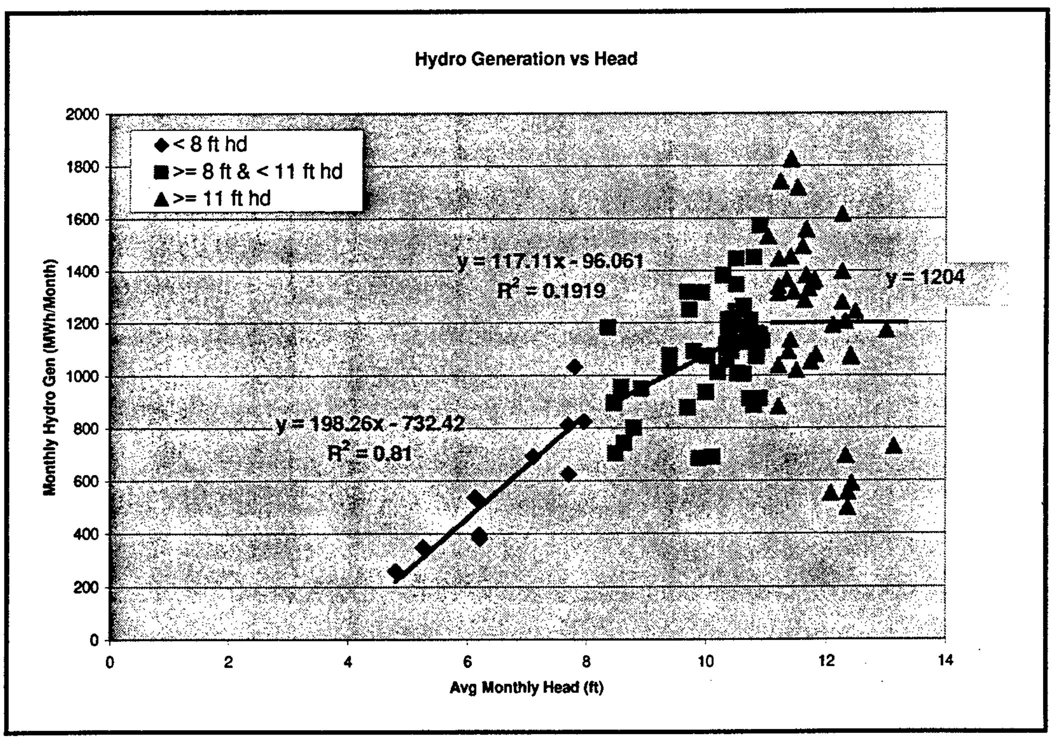


Figure 38. RIA hydroelectric electric energy production.

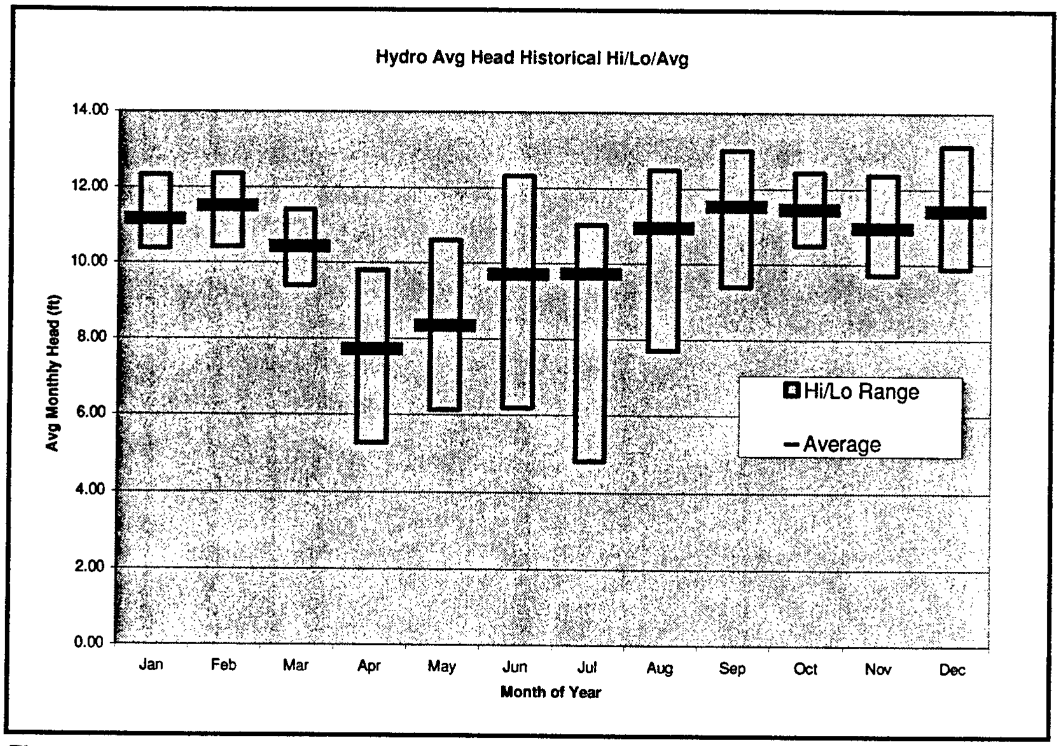


Figure 39. Historical hydroelectric head (ft) mean and extremes.

The peak hydroelectric power output correlates with monthly electric generation from the plant (Figure 40).

Purchased electricity is the result of the following general equation, which is valid for electric energy and peak demand.:

$$E_{Purch} = E_{Load} - E_{Hydro} - E_{MCFC} \qquad \text{[Eq 2]}$$

Where: E_{Purch} = Purchased Electricity
E_{Load} = Arsenal Electric Load
E_{Hydro} = Hydroelectric Production
E_{MCFC} = Fuel Cell Electric Production.*

The cost of electric purchases is determined by applying the correct electric energy and demand charges from MidAmerican's Rate Schedule No. 53. No uncertainty is associated, in this model, with this rate schedule although the future cost of electricity may change. The electric rate was set deterministically because it is essentially fixed for long periods until the next rate change.

* An explanation of the MCFC electric production model may be found later in this section.

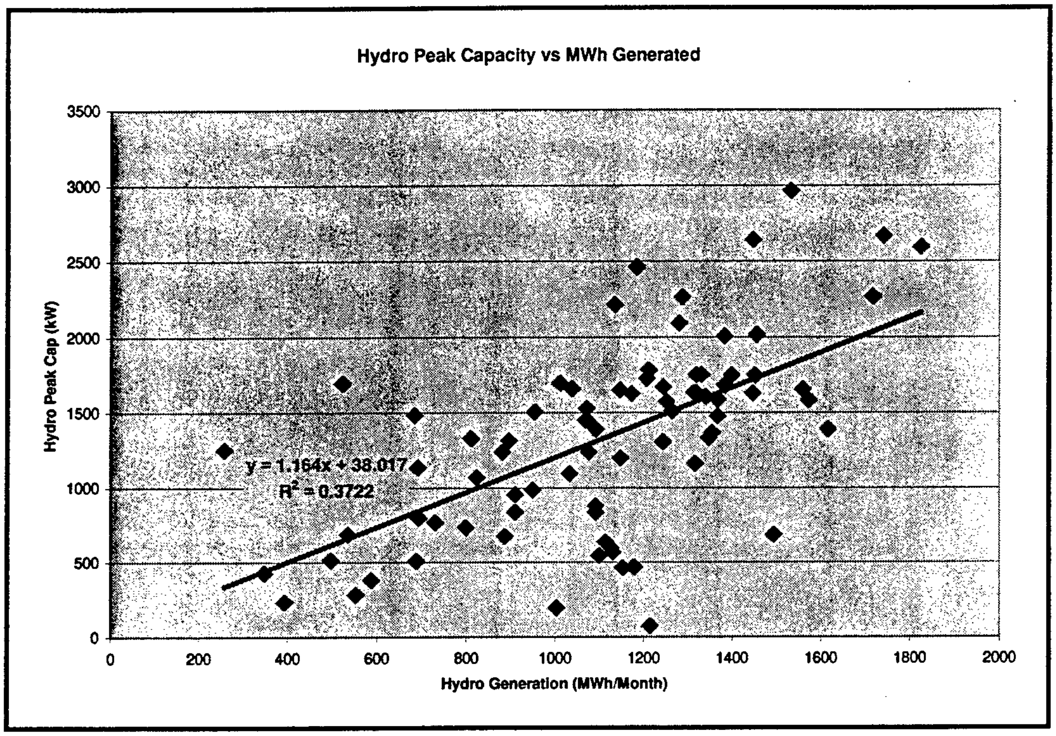


Figure 40. Hydroelectric peak capacity correlation.

Thermal Load and Price

The majority of RIA's thermal load is met with the Central Heating Plant. This heating plant generates steam, which is distributed through the Arsenal. The thermal load can be separated into process and space-heating loads. (This model element ignores the natural gas load which also provides thermal energy. Natural gas loads are handled separately in the model.) The process load varies according to manufacturing production. The space-heating load correlates well with ambient conditions.

The process thermal load was determined by examining data points where the load flattens out as a function of ambient temperature. This occurs approximately at average monthly temperature of 65 °F. These loads average 22,246 MMBtu/month and vary between a maximum of 34,854 and a minimum of 18,535 MMBtu/month. To model these loads, a triangular probability distribution is defined using the average historical load as the mode and the minimum and maximum data as the extreme ranges. Figure 41 shows this distribution.

For the Arsenal space-heating load a correlation was developed with the ambient temperature. Figure 42 shows this relationship.

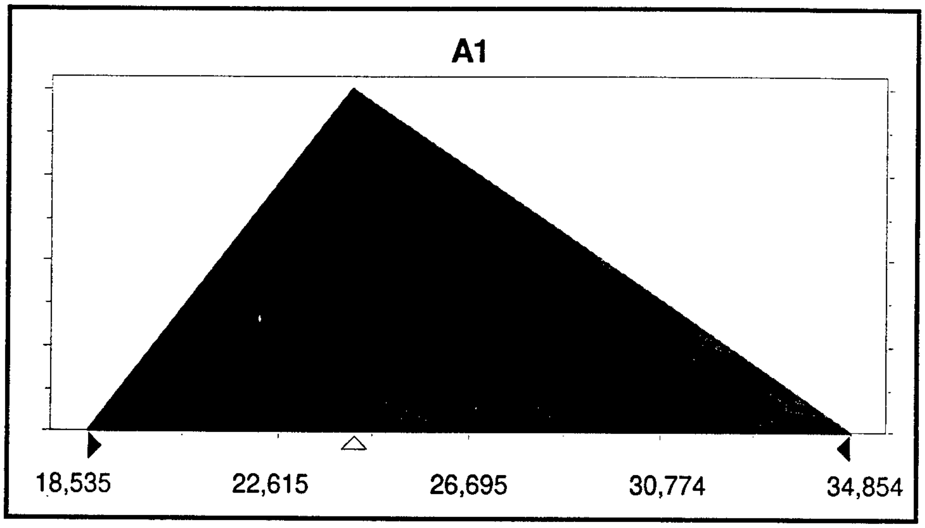


Figure 41. Probability distribution for process thermal loads.

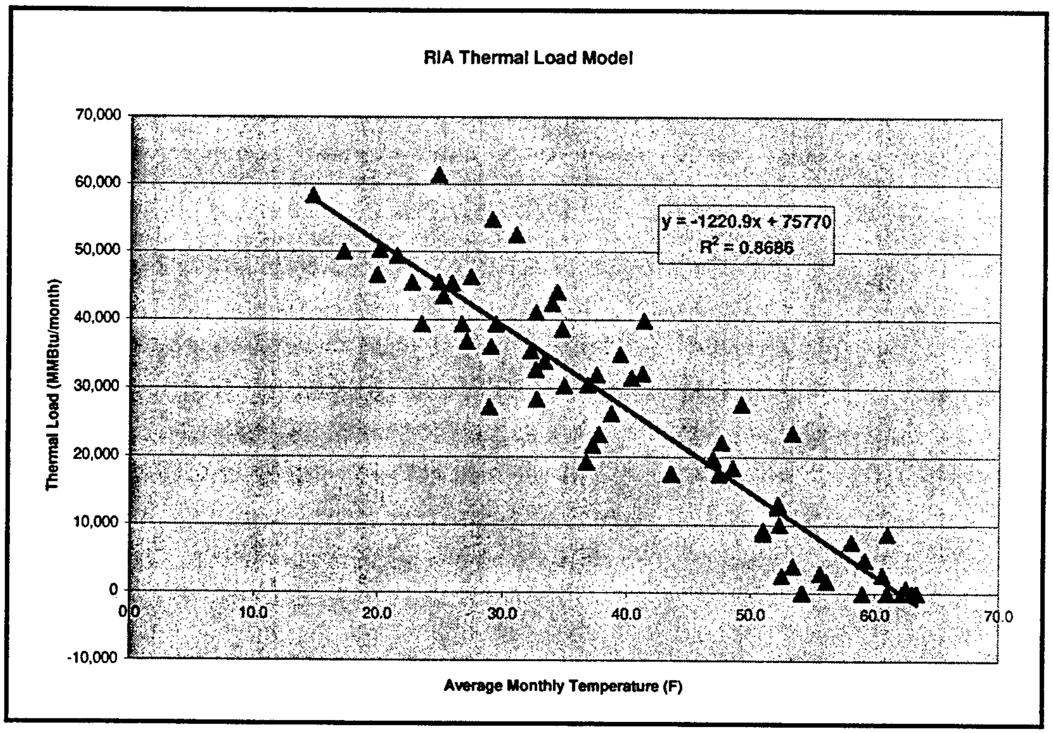


Figure 42. RIA space-heating thermal load correlation.

The separation of these two loads is important because the second model assumes that the process thermal loads are met with natural gas-fired package boilers and the space-heating load is met with geothermal heat pumps.

The fuel requirement for these thermal loads is determined depending on the assumed source. For the Central Heating Plant, coal consumption is determined by dividing steam production efficiency into the combined thermal load. Figure 43 shows that the steam production efficiency is a distribution curve derived from the historical Central Heating Plant performance.

The natural gas consumption and heat pump electric consumption are determined by dividing the efficiencies of these two systems into the process and space-heating thermal loads respectively. Probability distributions for these efficiencies were developed and can be found in the assumptions in Appendix E.

Natural Gas Load and Price

Historically, RIA consumes a relatively modest amount of natural gas. Since RIA's natural gas consumption correlates with ambient temperature, a linear model was developed that included an uncertainty term. Figure 44 shows RIA's natural gas load with respect to ambient average temperature.

This natural gas consumption is in addition to the MCFC power plant consumption and the process boiler gas consumption, which can be found in model assuming geothermal heat pump installation. These additional natural gas loads are aggregated to determine total Arsenal load.

Natural gas rates are somewhat correlated with ambient temperature. This is probably a supply-wide effect reflecting high demand during periods of low temperature. Figure 45 shows this relationship.

In this instance, the correlation equation is an exponential curve that has an uncertainty term added to account for the variance with historical data.

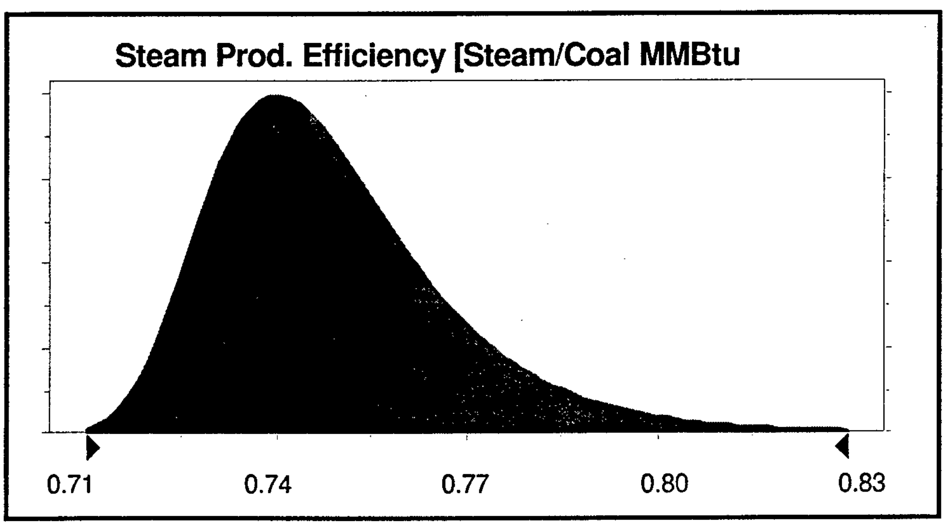


Figure 43. Steam production efficiency distribution.

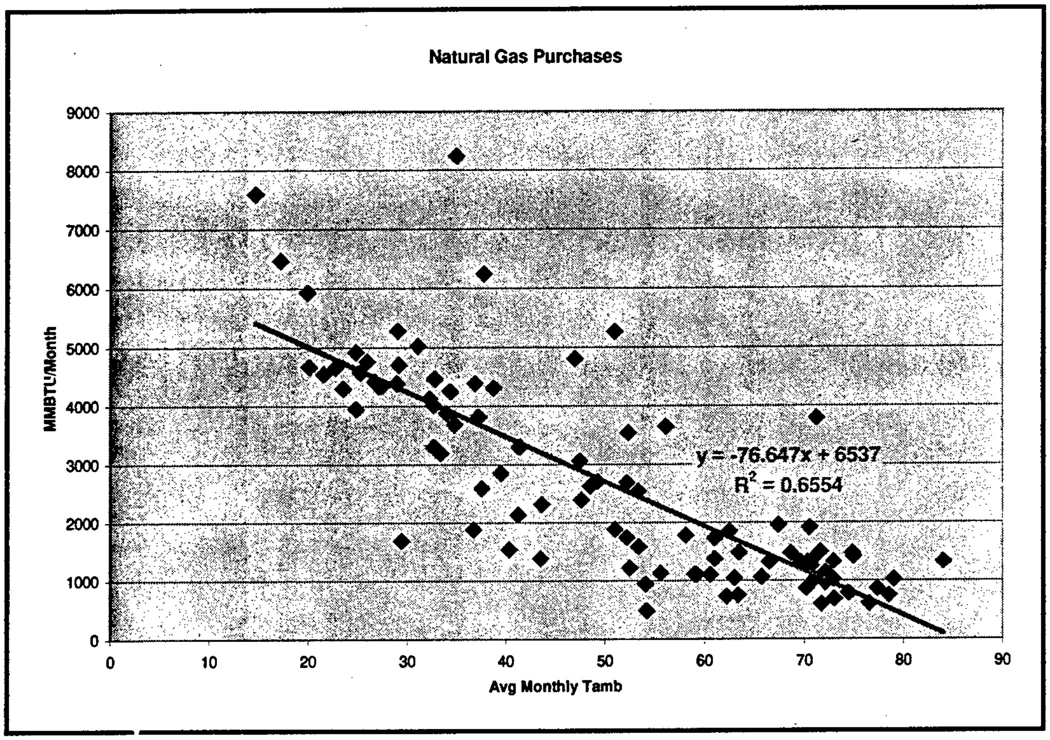


Figure 44. RIA natural gas consumption correlation.

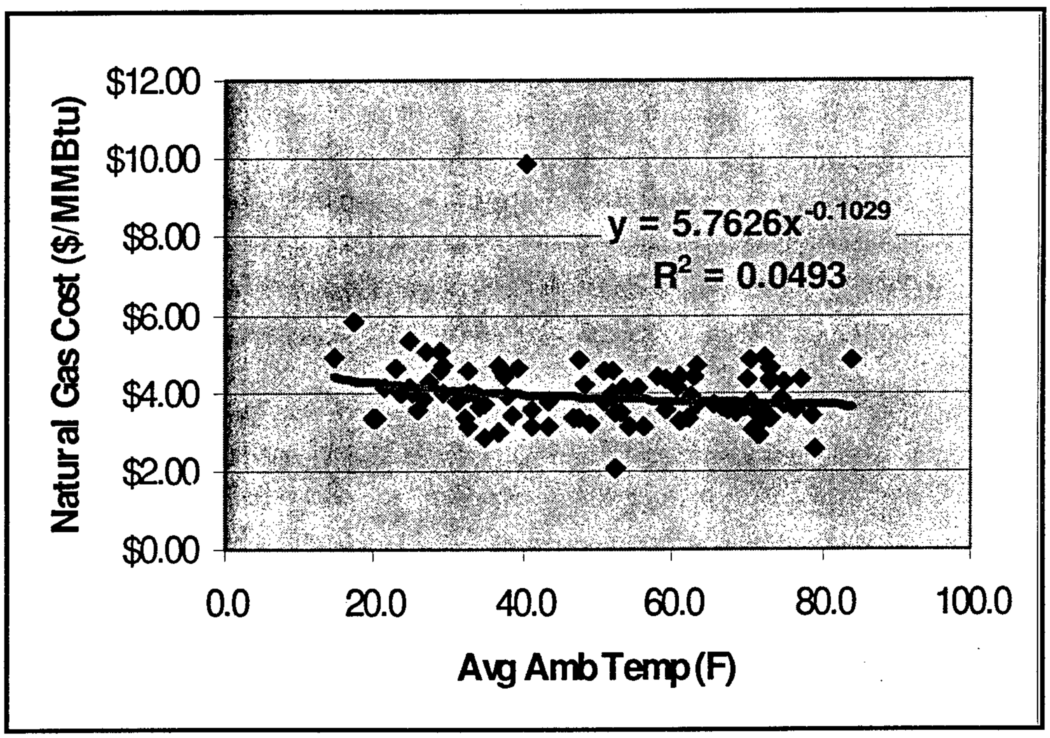


Figure 45. RIA natural gas price correlation.

Weather Conditions

Many of the equations developed for this model used average ambient temperature. To correctly model ambient conditions at the Arsenal, average, minimum, and maximum average ambient temperatures for a fifty year period (1943 to 1993)* were used to develop probability profiles.

Gaussian probability distributions were used to model monthly temperature variations. In these distributions, the mean was the historical average and the minimum and maximum temperatures were equated to three standard deviations. Distributions were developed for each month of the year. Figure 46 shows an example of an ambient temperature distribution. All correlation equations in this model that use ambient temperatures as an independent variable depend on the outputs of these distributions when the stochastic engine is running.

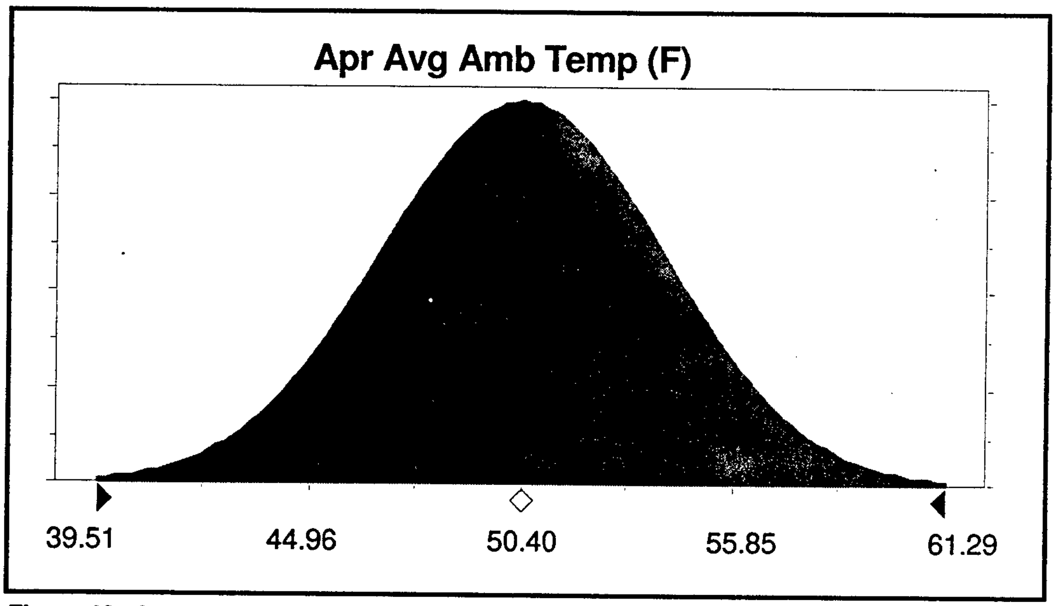


Figure 46. Average ambient temperature distribution for April.

* The data was provided by the Global Historical Climatology Network (GHCN), which is a comprehensive global surface baseline climate data set designed for monitoring and detecting climate change. Comprised of surface station observations of temperature, precipitation, and pressure, all GHCN data are taken on a monthly basis. GHCN is produced jointly by the National Climatic Data Center, Arizona State University, and Carbon Dioxide Information Analysis Center at Oak Ridge National Laboratory.

Fuel Cell and Other Equipment

The fuel cell, natural gas fuel boiler, and geothermal heat pumps are characterized by their performance. All three have efficiencies assigned to them. The MCFC has the additional parameters of capacity and availability. The fuel cell parameters are constants while the efficiencies of the boiler and heat pumps are probability distributions. Since the MCFC power plant is to be designed to these specifications, it is believed that it can meet the defined performance parameters with fairly high certainty.

Avoided Emissions

Avoided air emissions from bulk power generation, coal used in the Central Heating Plant, and natural gas used for package boilers in the geothermal heat pump case are calculated in the model using emission factors for each source. The MCFC power plant air emissions, although very small, are included in the net results for completion.

Modeling Results

The following sections describe the results of the modeling effort.

Fuel Cell With Central Heating Plant

The first model assumed that the central heating plant would remain in service during the fuel cell operation. Average results were determined using this assumption (Table 31).

These mean values indicate that the MCFC power plant would avoid over $300,000 in annual coal and electric costs, but increase the natural gas cost by over $200,000. The resulting net annual saving is $82,709.

Table 31. Potential mean savings with MCFC fuel cell (with central steam plant).

Energy Type	Annual Savings
Electric energy	$201,625
Electric demand	$76,400
Natural gas	-$222,882
Coal	$27,566
Total net savings	*$82,709*

However, the forecasted distributions (Figure 47) show that the total savings, at 80 percent certainty, can be from $40,000 to $120,000 per year. The performed sensitivity analysis showed that the natural gas price is the largest contributor to the total savings uncertainty. This indicates that a lower natural gas price would have a larger impact on increasing savings than any other variable evaluated in this model.

Figure 48 shows the distributions for each of the energy cost components. Note that the largest distribution range is the increased natural gas cost, which directly reflects the assumed uncertainty in natural gas price. Also, note the multiple distributions for electric demand savings. This is due to the tiered rate schedule for electric demand, which depends on time of year and time of day usage.

Figure 49 illustrates the forecasted probability distribution for avoided emissions from the MCFC fuel cell. This includes the emissions produced by the fuel cell itself. Thus, these are net results.

Fuel Cell Without Central Heating Plant

RIA is considering the retirement of the Central Heating Plant. Under this scenario, process heating loads would be served by packaged boilers fueled with natural gas. Space heating needs would be met with geothermal heat pumps.

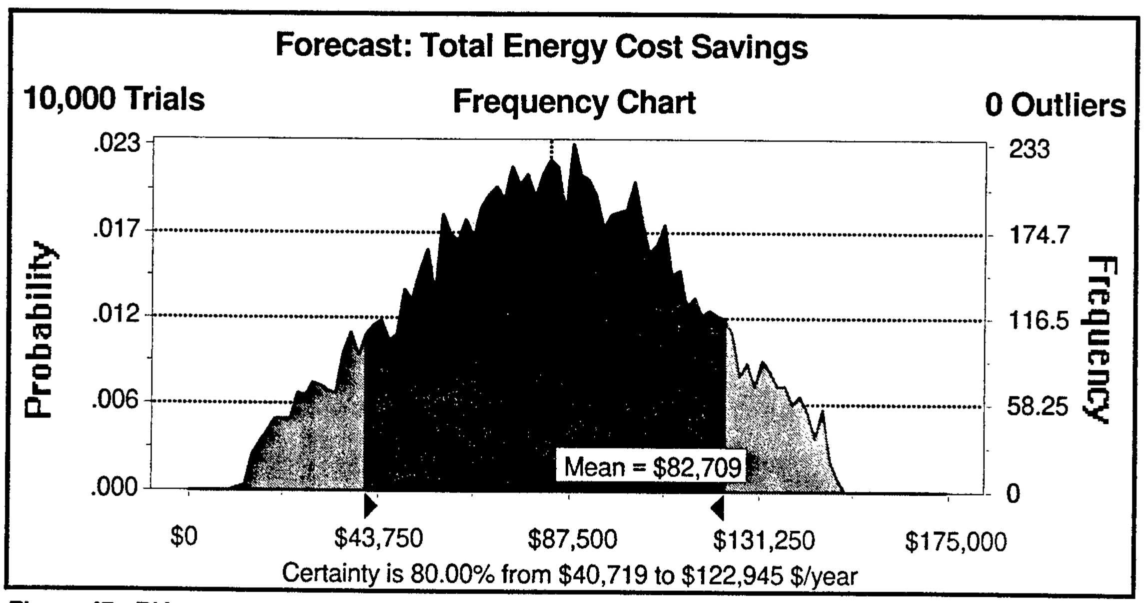


Figure 47. RIA net energy cost savings with MCFC power plant (assuming central heating plant operation).

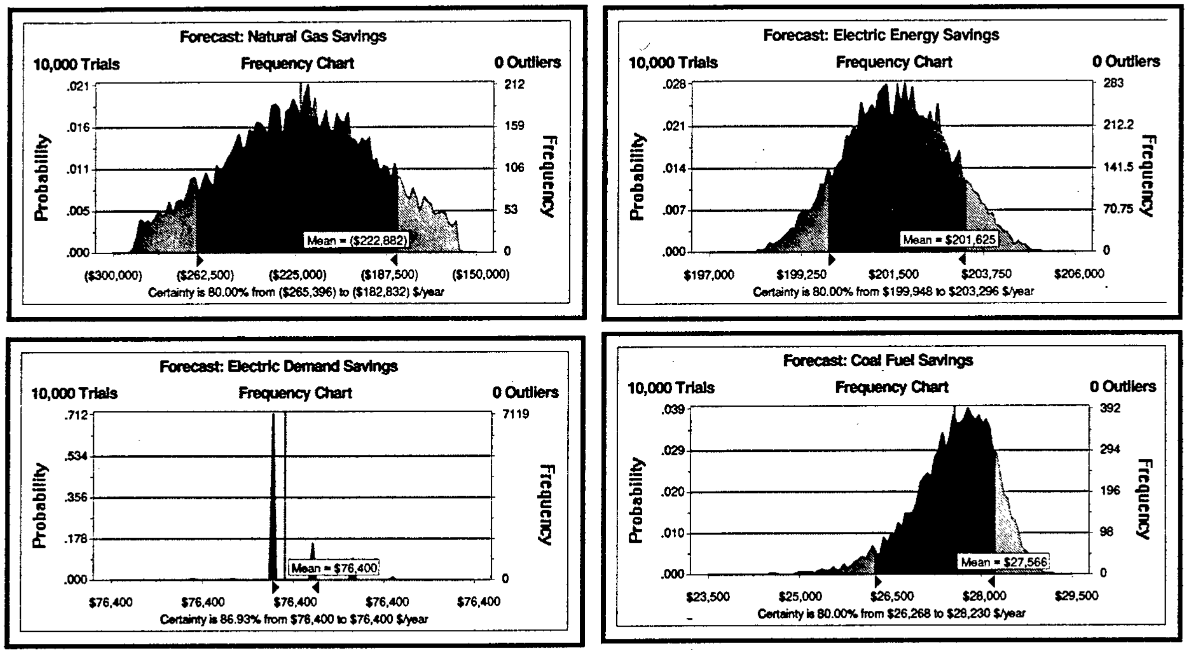


Figure 48. RIA energy savings resulting from MCFC installation (assuming central heat plant operation).

To model the fuel cell benefits under this scenario, equipment performance parameters for the package boilers and geothermal heat pumps were added. Space-heating loads were aggregated into RIA's electric load and package boiler fuel consumption was included with the natural gas load of the Arsenal.

Table 32 summarizes the mean results from the model. The mean total net savings was 25 percent higher than the first model, which assumed Central Heating Plant operation. This is primarily due to the increased value of the MCFC waste heat. In this model, the fuel cell's waste heat displaces natural gas, which is a more costly fuel than coal.

Figure 50 shows that, at 80 percent certainty, the total savings ranges from $70,000 to $134,000. Sensitivity analysis indicates that the key driver to this range is natural gas price uncertainty.

Figure 51 shows the forecast energy savings components. Note that coal savings are not reported because no coal is used in this model scenario.

Figure 52 shows avoided annual air emissions resulting from the installation of the fuel cell are shown as probability distributions. Note that the level of avoided emissions is lower than calculated with the Central Plant scenario. This is due to the increased use of natural gas and elimination of coal fuel.

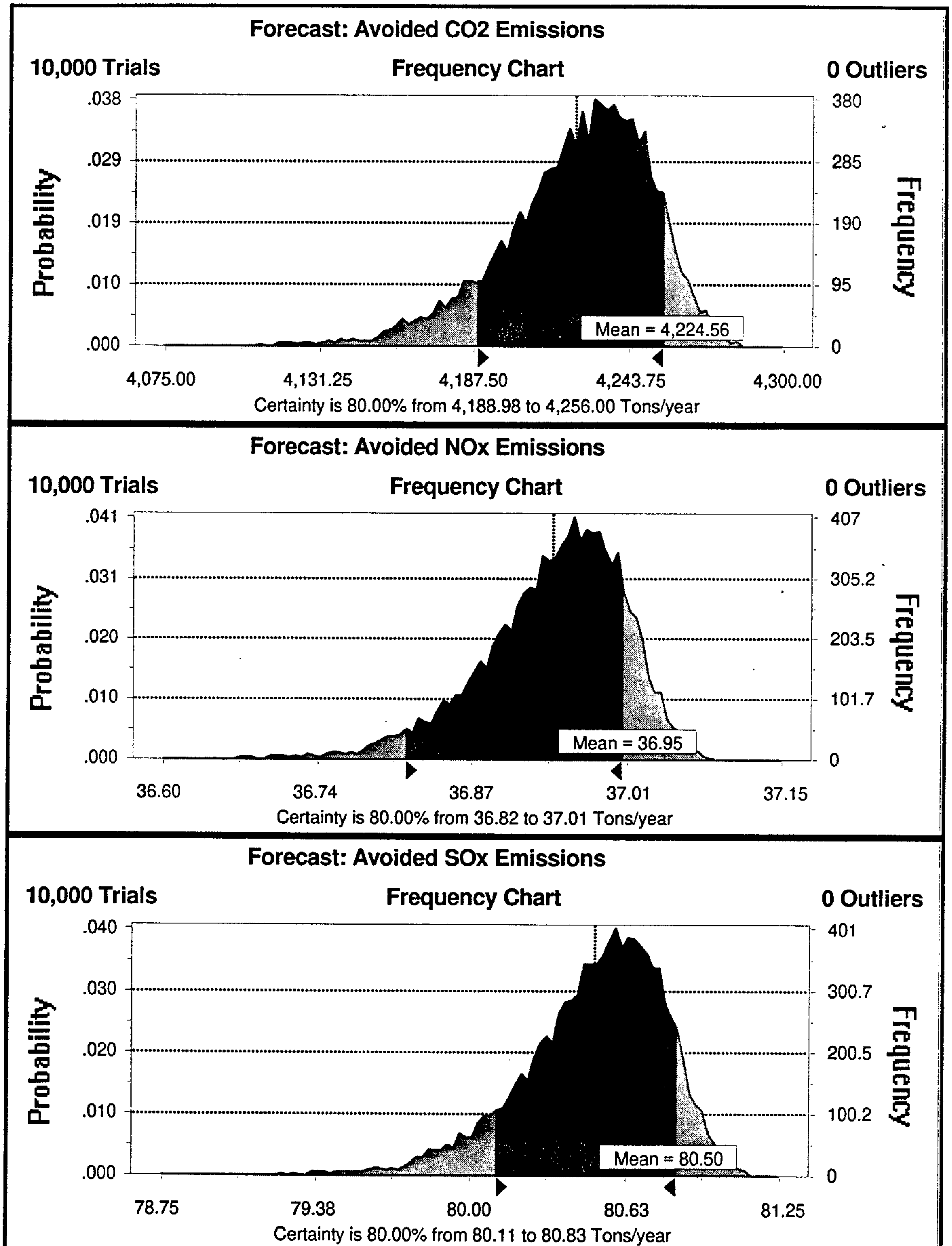


Figure 49. RIA avoided emissions with MCFC power plant installation (assuming central heating plant operation).

Table 32. Potential mean savings with MCFC fuel cell (with geothermal heat pumps).

Energy Type	Annual Savings
Electric Energy	$201,591
Electric Demand	$76,400
Natural Gas	-$176,081
Coal	$0
Total Net Savings	$101,909

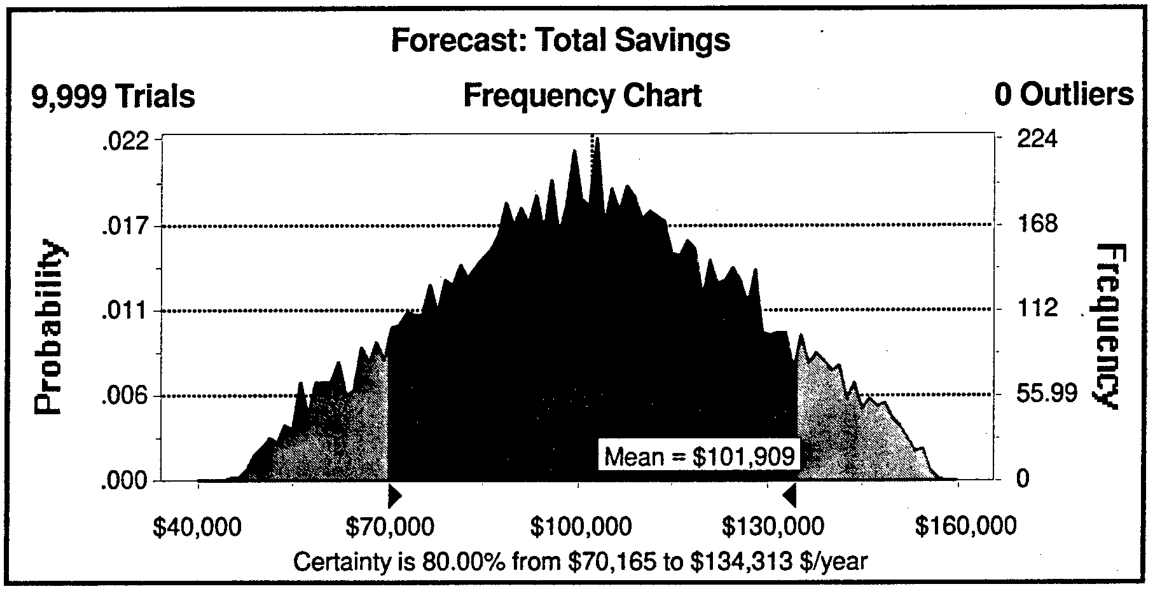


Figure 50. RIA net energy cost savings with MCFC power plant (assuming geothermal heat pump installation).

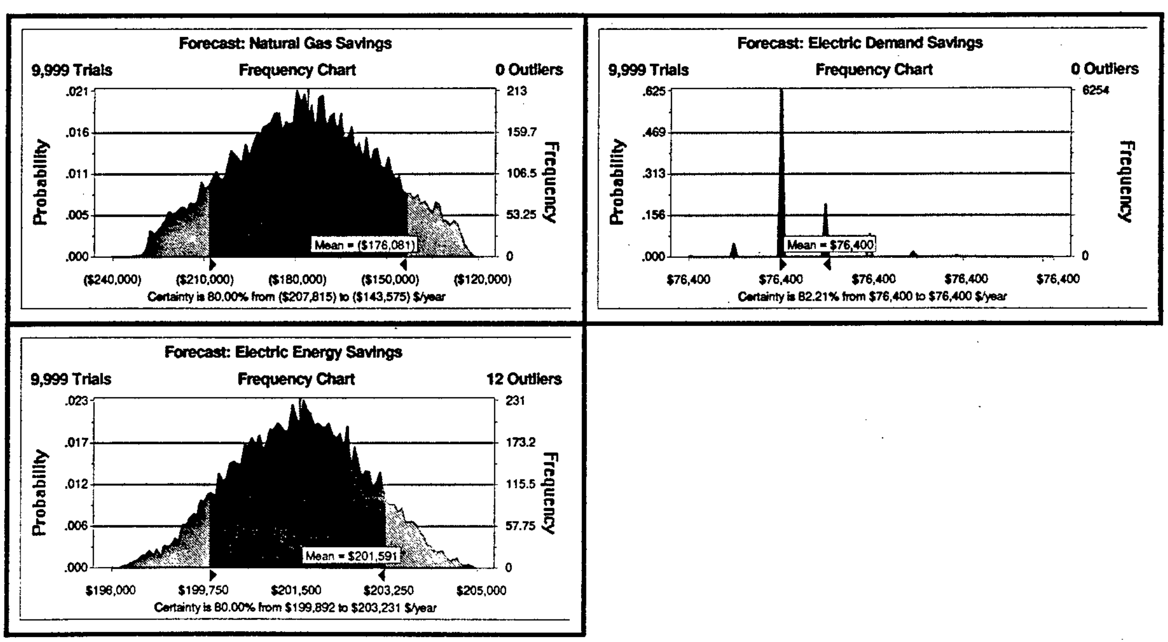


Figure 51. RIA energy savings resulting from MCFC installation (assuming geothermal heat pump installation).

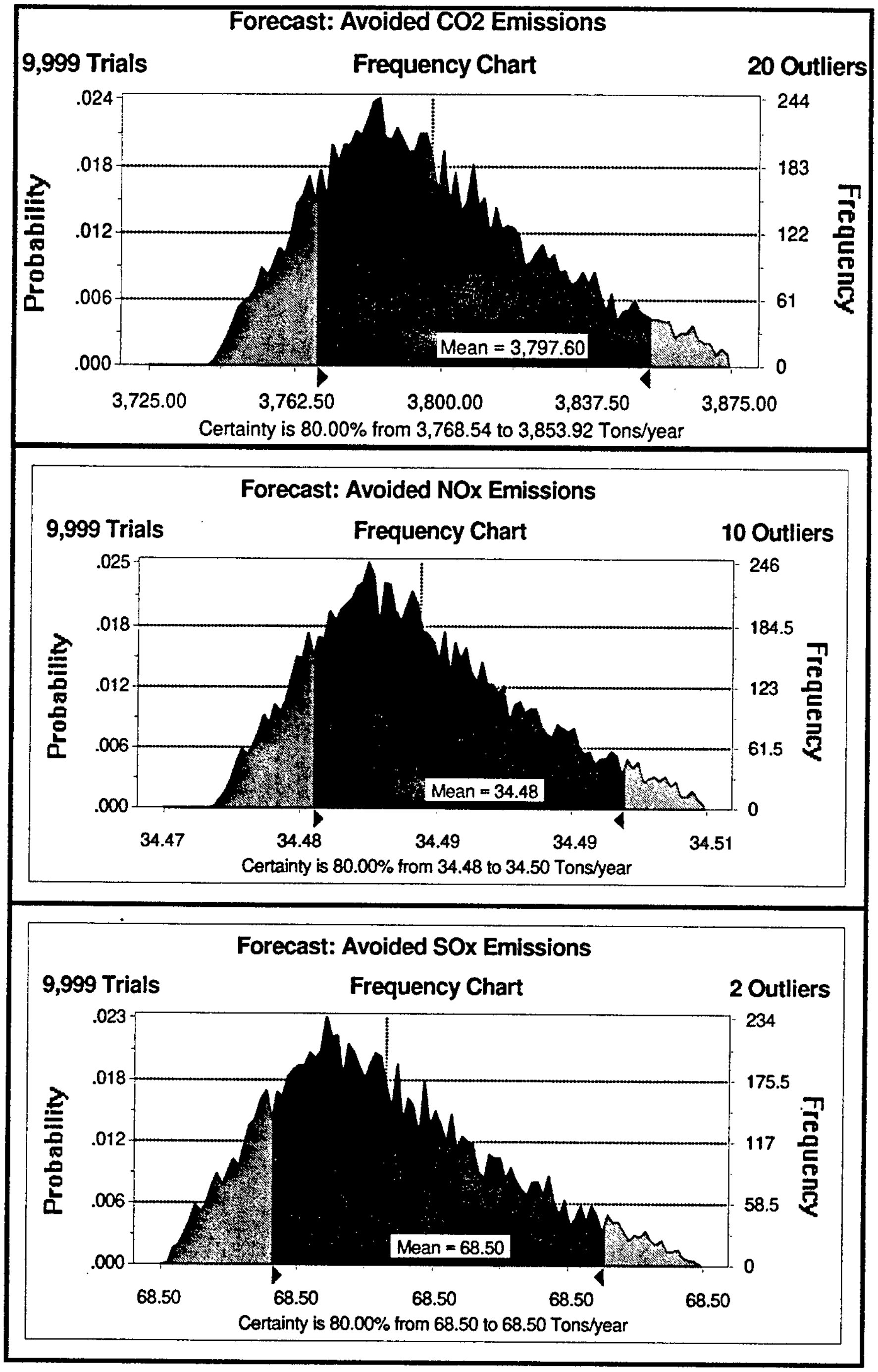


Figure 52. RIA avoided emissions with MCFC power plant installation (assuming central heating plant operation).

5 Summary of Fuel Cell Benefits

The table below summarizes the energy savings results from the modeling effort. These results are reported as mean, minimum and maximum values at 80 percent certainty (Table 33). Appendix H gives a more complete listing of energy benefits.

Table 33. Summary of annual fuel cell energy savings at RIA.*

	With Central Heating Plant			With Geo. Heat Pump		
Energy Type	**Min.**	**Mean**	**Max.**	**Min.**	**Mean**	**Max.**
Electric Energy	$199,948	$201,625	$203,296	$199,892	$201,591	$203,231
Electric Demand	$76,400	$76,400	$76,400	$76,400	$76,400	$76,400
Natural Gas	-$265,396	-$222,882	-$182,832	-$207,815	-$176,081	-$143,575
Coal	$26,268	$27,566	$28,230	$0	$0	$0
Total Net Savings	$40,719	$82,709	$122,945	$70,165	$101,909	$134,313

*Rounding may cause min, mean, and max to be equivalent.

The avoided emissions resulting from the fuel cell installation are summarized in Table 34.

Table 34. Summary of annual avoided air emissions (tons/year).

	With Central Heating Plant			With Geo. Heat Pump		
Emission	**Min.**	**Mean**	**Max.**	**Min.**	**Mean**	**Max.**
CO_2	4,189	4,225	4,256	3,769	3,798	3,854
NO_x	36.82	36.95	37.01	34.48	34.48	34.50
SO_x	80.11	80.50	80.83	68.50	68.50	68.50

6 Conclusions

This study has investigated the feasibility of siting a 1 MW molten carbonate fuel cell at Rock Island Arsenal.

Phase I (Chapter 2) summarized relevant MCFC siting data for each of the four candidate sites at Rock Island Arsenal, including utility connections, electrical distribution, natural gas, water, sewer, and telecommunication systems, and also the required foundations. Table 4 (p 35) summarizes the four sites by ranked criteria.

Phase II (Chapter 3) gave a more detailed description of fuel cell siting characteristics, interface requirements, and preliminary design details. Phase II also analyzed and defined load management benefits resulting from application of the fuel cell, interactions with installed ground source heat pumps, and electrical and thermal energy conservation opportunities at RIA.

Phase III (Chapter 4) provided a more detailed analysis of fuel cell benefits to RIA using the site specifics developed for the proposed MCFC site near the Central Heating Plant. Modeling conducted in the Phase III study indicates with a high degree of certainty that the proposed MCFC power plant installation at RIA has the potential to generate significant cost savings and environmental benefits. The potential savings is higher if the Central Heating Plant is retired. Fuel cell cost benefits will increase if natural gas prices fall.

References

Kneble, David E., *Simplified Energy Analysis Using the Modified Bin Method* (American Society of Heating, Refrigerating, and Air-Conditioning Engineers [ASHRAE], 1983).

Sliwinski, Benjamin J., et al., *Fixed Facilities Energy Consumption Investigation – Data Analysis*, USACERL Interim Report (IR) E-143 (U.S. Army Construction Engineering Research Laboratory, February 1979).

U.S. Environmental Protection Agency (USEPA), *Emissions Data Summary for 1996*.

Appendix A: Boiler Equipment Electrical Loads

Sorting Label	Unit Label								Data for all Motors and Heaters H.P.	Loads Required for 2 Boilers			Loads Required for 1 Boiler		
										H.P.	% Duty	Net HP	H.P.	% Duty	Net HP
MTR	AC	-	227	-	1	D	-	1	15	15	100	15	15	100	15
MTR	AC	-	227	-	1	D	-	3	25	25	100	25	25	100	25
MTR	AC	-	227	-	1		-	1	1	1	100	1	1	100	1
MTR	AC	-	227	-	3		-	1	3	3	0	0	3	0	0
MTR	AC	-	227	-	3		-	2	3	3	0	0	3	0	0
MTRT	ATM	-	227	-	2		-	1	5	5	100	5	5	100	5
MTR	AUM	-	227	-	2		-	1	1	1	100	1	1	100	1
MTR	BBM	-	227	-	3		-	1	1	1	100	1	1	100	1
MTR	BTM	-	227	-	3		-	1	10	10	100	10	10	100	10
MTR	CCM	-	227	-	B		-	1	2	2	40	0.8	2	40	0.8
MTR	CEM	-	227	-	3		-	1	10	10	100	10	10	100	10
MTR	CGM	-	227	-	B		-	1	25	25	100	25	25	100	25
MTR	CHM	-	227	-	1		-	1	7.5			0			0
MTR	GDM	-	227	-	1		-	1	20			0			0
MTR	GDM	-	227	-	1		-	2	20	20	100	20			
MTR	GDM	-	227	-	1		-	3	1.5			0			0
MTR	GDM	-	227	-	1		-	4	2			0			0
MTR	GM	-	227	-	1		-	1	1.5			0			0
MTR	KGM	-	227	-	1	M	-	1				0			0
MTR	KGM	-	227	-	1	M	-	2		0	1	0			
MTR	KGM	-	227	-	1	M	-	3		0	1	0	0	1	0
MTR	KGM	-	227	-	1	M	-	4				0			0
MTR	LMM	-	227	-	1		-	1	1.5	1.5	100	1.5	1.5	100	1.5
MTR	PEM	-	227	-	B		-	1	5	5	100	5	5	100	5
MTR	SFM	-	227	-	1		-	1	2	2	100	2	2	100	2
MTR	SFM	-	227	-	1		-	2	1			0			0
MTR	VCM	-	227	-	1		-	1	25			0			0
MTR	WLTM	-	227	-	1		-	1		0	75	0	0	75	0
PUMP	ASP	-	227	-	R		-	1	100	100	25	25	100	25	25
PUMP	BFP	-	227	-	B		-	2	150			0			0
PUMP	BFP	-	227	-	1		-	1	60	60	100	60	60	100	60
PUMP	BRP	-	227	-	1		-	1	1.5	1.5	50	0.75	1.5	50	0.75
PUMP	BTP	-	227	-	1		-	1	3	3	5	0.15	3	5	0.15
PUMP	CP	-	227	-	B		-	1	1	1	100	1	1	100	1

Sorting Label	Unit Label								Data for all Motors and Heaters H.P.	Loads Required for 2 Boilers			Loads Required for 1 Boiler		
										H.P.	% Duty	Net HP	H.P.	% Duty	Net HP
PUMP	CP	-	227	-	1		-	1	25			0			0
PUMP	CP	-	227	-	1		-	2	25			0			0
PUMP	CP	-	227	-	1		-	3	25	25	100	25	25	100	25
PUMP	CP	-	227	-	1		-	4	25	25	100	25	25	100	25
PUMP	FBP	-	227	-	1		-	1	15	15	100	15	15	100	15
PUMP	FBTP	-	227	-	2		-	1	2	2	100	2	2	100	2
PUMP	LCP	-	227	-	1		-	1	4			0			0
PUMP	LCP	-	227	-	1		-	2	1			0			0
PUMP	RP	-	227	-	B		-	1	3	3	100	3	3	100	3
PUMP	RBP	-	227	-	1		-	1	25	25	10	2.5	25	10	2.5
PUMP	RBP	-	227	-	1		-	2				0			0
PUMP	SP	-	227	-	B		-	1		0	50	0	0	50	0
PUMP	SRP	-	227	-	1		-	1	3	3	100	3	3	100	3
PUMP	TWP	-	227	-	1		-	1	15	15	100	15	15	100	15
PUMP	ZBP	-	227	-	2		-	1	15	15	100	15	15	100	15
FAN	CAF	-	227	-	1	DM	-	1	25	25	100	25	25	100	25
FAN	CAF	-	227	-	1	DM	-	2	25			0			0
FAN	EF	-	227	-	B	D	-	1	10	10	50	5	10	50	5
FAN	EF	-	227	-	B		-	1	5	5	40	2	5	40	2
FAN	EF	-	227	-	3		-	1	5			0			0
FAN	EF	-	227	-	3		-	2	5			0			0
FAN	EF	-	227	-	R		-	1	3	3	100	3	3	100	3
FAN	FDF	-	227	-	1	DM	-	1	50			0			0
FAN	FDF	-	227	-	1	DM	-	2	50	50	100	50			
FAN	FDF	-	227	-	1	DM	-	3	50	50	100	50	50	100	50
FAN	FDF	-	227	-	1	DM	-	4	25			0			0
FAN	IDF	-	227	-	3		-	1	250			0			0
FAN	IDF	-	227	-	3		-	2	250	250	100	250			
FAN	IDF	-	227	-	3		-	3	400	400	100	400	400	100	400
FAN	IDF	-	227	-	3		-	4	200			0			0
FAN	OFF	-	227	-	1	M	-	1	20			0			0
FAN	OFF	-	227	-	1	M	-	2	20	20	100	20			
FAN	RAF	-	227	-	1	BH	-	1	50	50	30	15	50	30	15
FAN	RAF	-	227	-	2	BH	-	1	50	50	30	15	50	30	15
AHU	AHU	-	227	-	2		-	1	1	1	100	1	1	100	1

Sorting Label	Unit Label								Data for all Motors and Heaters H.P.	Loads Required for 2 Boilers			Loads Required for 1 Boiler		
										H.P.	% Duty	Net HP	H.P.	% Duty	Net HP
AHU	MAU	-	227	-	1	M	-	1	7.5			0			0
AHU	MAU	-	227	-	1	M	-	2	7.5			0			0
AHU	MAU	-	227	-	1	M	-	3	7.5			0			0
AHU	MAU	-	227	-	1	M	-	4	7.5			0			0
AHU	MAU	-	227	-	1	M	-	5	7.5			0			0
AHU	MAU	-	227	-	1	M	-	6	7.5			0			0
HH	HH	-	227	-	1	W	-	1			50	0			
HH	HH	-	227	-	1	W	-	2			50	0			
HH	HH	-	227	-	1	W	-	3			50	0			
HH	HH	-	227	-	1	W	-	4			50	0			
HH	HH	-	227	-	1	W	-	5			50	0			
HH	HH	-	227	-	1	W	-	6			50	0			
HH	HH	-	227	-	1	W	-	7			50	0			
HH	HH	-	227	-	1	W	-	8			50	0			
HH	HH	-	227	-	1	W	-	9			50	0			
HH	HH	-	227	-	1	W	-	10			50	0			
HH	HH	-	227	-	1	E	-	1			50	0		50	0
HH	HH	-	227	-	1	E	-	2			50	0		50	0
HH	HH	-	227	-	1	E	-	3			50	0		50	0
HH	HH	-	227	-	1	E	-	4			50	0		50	0
HH	HH	-	227	-	1	E	-	5			50	0		50	0
HH	HH	-	227	-	1	E	-	6			50	0		50	0
HH	HH	-	227	-	1	E	-	7			50	0		50	0
HH	HH	-	227	-	1	E	-	8			50	0		50	0
HH	HH	-	227	-	1	E	-	9			50	0		50	0
HH	HH	-	227	-	1	E	-	10			50	0		50	0
												1150.7			810.7

Appendix B: Gas Odorant Data Sheet

BP Captan - Natural Gas Odorant Data Sheet				
Physical Properties				
Boiling Range			Reid Vapor Pressure	
IBP	139 °F	59.4 °C	psia @ 100 °F	6.4
95 %	150 °F	65.6 °C	kg/cm2 @ 37.78 °C	0.45
D.P.	151 °F	66.1 °C		
Wt. Average Molecular	87		Mercaptan Content (% by volume)	99+
Specific Gravity			Sulfur Content (% by Wt.)	37
(60/60 °F) (15 °C)	0.808		Corrosion - Copper Strip	Negligible
Density (60 °F) lbs./gal	6.73		(24-hr immersion test)	
(15 °C) kgm./liter	0.806		Solubility in Water	Trace
Cloud Point (Max.)	-50 °F	-45.6 °C	Flash Point (open cup) °F	-16
Freezing Point (below)	-60 °F	-51.1 °C	°C	-26.7

Analysis			
Weight %			
Component	**Minimum**	**Typical**	**Maximum**
Ethyl Mercaptan	0.0	0.0	1.0
Isopropyl Mercaptan	14.0	20.0	22.0
Tertiary Butyl Mercaptan	75.0	77.0	80.0
Normal Propyl Mercaptan	2.0	3.0	7.0
Secondary Butyl Mercaptan	0.0	0.0	4.0

Appendix C: Rock Island Arsenal Energy Consumption Database

		Electrical Consumption							Coal Consumption							Weather Conditions			Natural Gas Consumption		
Date	Season	Mega Watt-Hours Purchased	Mega Watt-Hours Generated	Total Usage	Average River Head	Purchased Peak Demand	Total Peak Demand	Hydro-Electric Demand	Coal Consumption	Btu/LB Content	Steam Produced	>=65F	<65F	KLBS Steam Produced/MMBtu Consumed	Coal Unit Cost	Avg Temperature	Heating Degree Days	Cooling Degree Days	Month's Bill (Purchased)	Total Gas Purchased	Gas Unit Cost
		MWH/ Month	MWH/ Month	MWH/ Month	ft	kW	kW	kW	MMBtu/ Month	Btu/lb	klbs/ Month			klbs/ MMBtu	$/klbs	°F	HDD/ Month	CDD/ Month	$/Month	MMBtu/ Month	$/ MMBtu
Jan-92	Winter	7,756	1,130	8,886	10.93	18,472	19,038	566	105,354	12,279	83,493		83,493	0.793	2.480	29.1	1,107	0	$18,799	4,707	$3.99
Feb-92	Winter	6,482	1,286	7,768	11.63	16,594	18,858	2,264	94,057	12,279	72,804		72,804	0.774	2.539	34.3	884	0	$15,968	4,249	$3.76
Mar-92	Winter	7,798	1,010	8,808	10.20	17,476	19,170	1,694	88,605	12,279	68,565		68,565	0.774	2.540	41.3	726	0	$10,254	3,303	$3.10
Apr-92	Winter	7,798	948	8,746	8.93	18,144	19,129	985	72,913	12,279	56,418		56,418	0.774	2.540	49.2	473	6	$8,579	2,705	$3.17
May-92	Winter	8,232	1,073	9,305	10.02	18,862	20,307	1,445	50,221	12,279	37,368		37,368	0.744	2.642	61.0	181	61	$5,653	1,731	$3.27
Jun-92	Summer	8,442	1,205	9,647	12.31	18,887	20,613	1,726	43,394	12,279	33,563	33,563		0.773	2.541	68.6	27	143	$5,149	1,476	$3.49
Jul-92	Summer	9,324	1,070	10,394	10.83	19,152	20,679	1,527	45,039	12,279	34,854	34,854		0.774	2.540	70.5	3	181	$7,155	1,914	$3.74
Aug-92	Summer	8,008	1,068	9,076	12.41	19,228	20,679	1,451	41,478	12,279	32,114	32,114		0.774	2.539	67.4	33	115	$7,027	1,966	$3.57
Sep-92	Summer	8,064	881	8,945	11.20	19,328	20,565	1,237	37,770	12,279	29,386		29,386	0.778	2.526	62.5	147	77	$7,243	1,849	$3.92
Oct-92	Winter	7,308	1,824	9,132	11.41	17,136	19,732	2,596	68,328	12,455	52,168		52,168	0.763	2.583	53.3	370	16	$8,875	2,546	$3.49
Nov-92	Winter	7,182	1,315	8,497	9.93	17,539	18,700	1,161	93,163	12,455	71,096		71,096	0.763	2.584	33.9	927	0	$14,003	3,873	$3.62
Dec-92	Winter	7,952	684	8,636	9.89	18,358	19,842	1,484	106,366	12,455	81,195		81,195	0.763	2.584	31.0	1,049	0	$19,015	5,020	$3.79
Jan-93	Winter	6,174	1,178	7,352	10.37	17,942	18,410	468	99,389	12,752	74,220		74,220	0.747	2.552	24.8	1,241	0	$20,381	4,920	$4.14
Feb-93	Winter	5,908	1,279	7,187	12.26	16,771	18,864	2,093	90,973	12,752	68,080		68,080	0.748	2.547	23.5	1,156	0	$17,098	4,294	$3.98
Mar-93	Winter	7,056	1,133	8,189	10.40	17,305	19,519	2,214	90,259	12,752	67,340		67,340	0.746	2.555	34.7	936	0	$13,604	3,688	$3.69
Apr-93	Winter	7,938	348	8,286	5.26	18,949	19,375	426	62,918	12,752	47,016		47,016	0.747	2.551	48.5	488	0	$11,096	2,632	$4.22
May-93	Winter	7,854	535	8,389	6.12	19,625	20,313	688	36,700	12,752	27,428		27,428	0.747	2.550	63.0	116	60	$4,588	1,048	$4.38
Jun-93	Summer	8,372	523	8,895	6.18	19,114	20,809	1,695	34,277	12,752	25,580	25,580		0.746	2.554	70.3	53	217	$6,312	1,316	$4.80
Jul-93	Summer	9,338	257	9,595	4.80	19,348	20,599	1,251	32,518	12,752	24,261	24,261		0.746	2.555	84.0	0	335	$6,336	1,321	$4.80
Aug-93	Summer	8,092	811	8,903	7.70	20,033	21,362	1,329	34,099	12,752	25,442	25,442		0.746	2.554	74.9	1	317	$6,021	1,423	$4.23
Sep-93	Summer	7,854	1,037	8,891	9.40	18,283	19,942	1,659	33,691	12,752	25,135		25,135	0.746	2.555	61.0	153	39	$6,023	1,378	$4.37
Oct-93	Winter	7,406	1,330	8,736	11.70	17,199	18,950	1,751	55,752	12,752	41,732		41,732	0.749	2.546	52.2	405	13	$7,025	1,754	$4.01

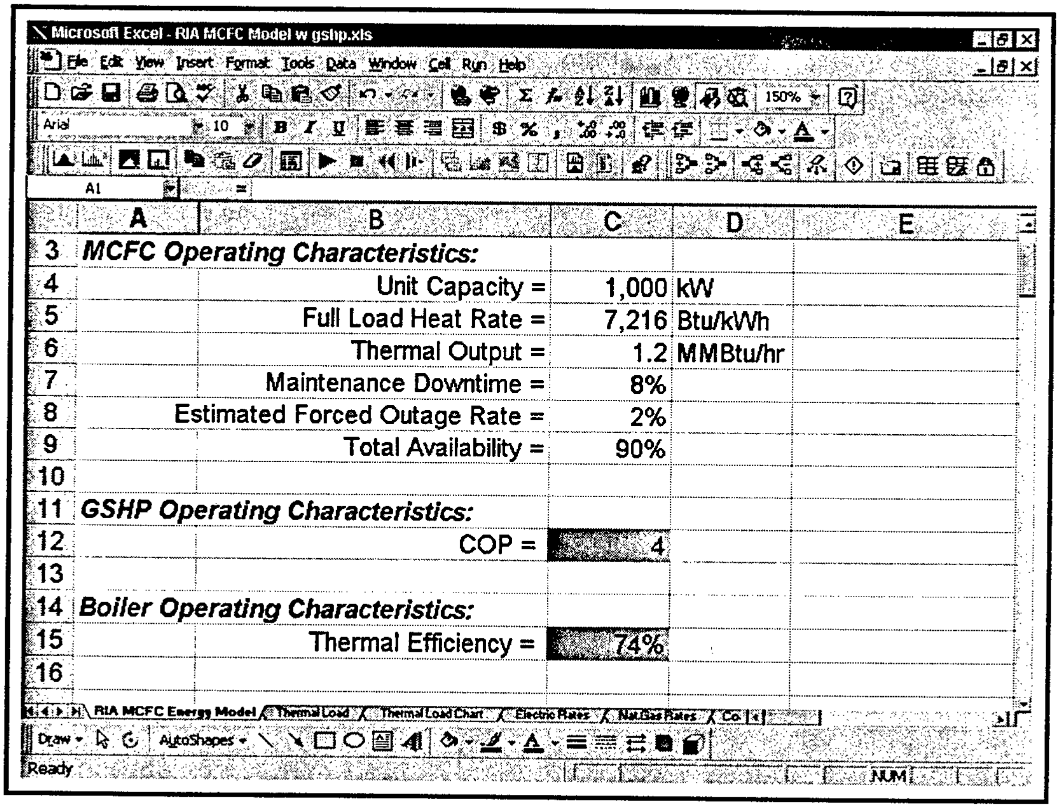
Date	Season	Electrical Consumption							Coal Consumption							Weather Conditions			Natural Gas Consumption		
		Mega Watt-Hours Purchased	Mega Watt-Hours Generated	Total Usage	Average River Head	Purchased Peak Demand	Total Peak Demand	Hydro-Electric Demand	Coal Consumption	Btu/LB Content	Steam Produced	>=65F	<65F	KLBS Steam Produced/MMBtu Consumed	Coal Unit Cost	Avg Temperature	Heating Degree Days	Cooling Degree Days	Month's Bill (Purchased)	Total Gas Purchased	Gas Unit Cost
		MWH/ Month	MWH/ Month	MWH/ Month	ft	kW	kW	kW	MMBtu/ Month	Btu/lb	klbs/ Month			klbs/ MMBtu	$/klbs	°F	HDD/ Month	CDD/ Month	$/Month	MMBtu/ Month	$/ MMBtu
Nov-93	Winter	6,440	1,210	7,650	10.73	17,224	19,007	1,783	81,230	12,752	60,677		60,677	0.747	2.552	37.5	819	0	$11,382	2,593	$4.39
Dec-93	Winter	7,210	1,147	8,357	10.69	16,884	18,082	1,198	100,052	12,752	75,006		75,006	0.750	2.542	27.4	1,158	0	$18,422	4,341	$4.24
Jan-94	Winter	7,056	1,262	8,318	10.62	17,149	18,657	1,508	116,579	12,752	87,013		87,013	0.746	2.554	14.7	1,557	0	$37,093	7,594	$4.88
Feb-94	Winter	6,930	1,090	8,020	10.42	18,081	18,959	878	99,542	12,752	74,173		74,173	0.745	2.421	22.7	1,178	0	$21,419	4,659	$4.60
Mar-94	Winter	8,792	1,075	9,867	9.40	18,092	19,328	1,236	87,989	12,752	63,627		63,627	0.723	2.494	39.4	789	0	$13,226	2,851	$4.64
Apr-94	Winter	7,182	1,090	8,272	9.80	19,228	20,615	1,387	55,318	12,752	41,270		41,270	0.746	2.418	52.2	403	26	$12,151	2,683	$4.53
May-94	Winter	8,148	953	9,101	8.59	18,938	20,442	1,504	41,852	12,752	31,395		31,395	0.750	2.404	60.6	175	43	$4,586	1,106	$4.15
Jun-94	Summer	8,736	1,313	10,049	11.20	20,412	22,042	1,630	37,389	12,752	28,115	28,115		0.752	2.399	72.9	13	256	$4,427	1,027	$4.31
Jul-94	Summer	9,324	1,243	10,567	10.50	21,017	22,321	1,304	36,190	12,752	27,052	27,052		0.747	2.413	72.9	0	250	$2,936	691	$4.25
Aug-94	Summer	8,624	1,558	10,058	11.66	19,795	21,451	1,656	32,084	12,752	23,489	23,489		0.732	2.464	70.2	14	182	$3,789	874	$4.34
Sep-94	Summer	8,176	1,454	9,630	11.40	19,152	21,168	2,016	31,140	12,752	23,236	23,236		0.746	2.417	77.3	74	114	$3,747	868	$4.32
Oct-94	Winter	7,336	1,339	8,675	11.20	17,602	19,206	1,604	50,829	12,752	37,920		37,920	0.746	2.555	51.0	433	8	$8,591	1,884	$4.56
Nov-94	Winter	6,832	1,318	8,150	11.45	16,897	18,645	1,748	67,458	12,752	50,327		50,327	0.746	2.555	37.2	827	0	$17,381	3,817	$4.55
Dec-94	Winter	7,336	1,366	8,702	11.34	17,212	18,798	1,586	91,228	12,752	68,055		68,055	0.746	2.555	29.4	1,096	0	$7,969	1,694	$4.71
Jan-95	Winter	6,230	1,716	7,946	11.52	16,141	18,410	2,269	103,342	12,496	78,092		78,092	0.756	2.436	21.5	1,343	0	$18,609	4,546	$4.09
Feb-95	Winter	6,174	1,615	7,789	12.26	17,048	18,436	1,388	89,271	12,496	68,050		68,050	0.762	2.415	26.7	1,065	0	$17,114	4,424	$3.87
Mar-95	Winter	7,756	1,572	9,328	10.89	17,010	18,592	1,582	79,799	12,496	60,841		60,841	0.762	2.414	41.2	733	0	$7,617	2,143	$3.56
Apr-95	Winter	6,860	1,183	8,043	8.36	17,212	19,675	2,463	66,579	12,496	50,772		50,772	0.763	2.414	47.6	517	0	$8,071	2,399	$3.36
May-95	Winter	7,924	1,032	8,956	7.80	18,383	19,476	1,093	43,836	12,496	33,537		33,537	0.765	2.406	59.2	182	11	$3,923	1,113	$3.52
Jun-95	Summer	8,568	1,318	9,886	9.69	19,530	21,161	1,631	31,815	12,496	24,305	24,305		0.764	2.409	73.0	8	256	$2,302	683	$3.37
Jul-95	Summer	7,714	1,531	9,245	11.02	18,194	21,161	2,967	32,340	12,496	24,665	24,665		0.763	2.413	76.5	1	365	$2,150	607	$3.54
Aug-95	Summer	8,792	1,382	10,174	10.29	18,308	20,315	2,007	36,113	12,496	27,572	27,572		0.763	2.411	78.5	0	427	$2,551	753	$3.39

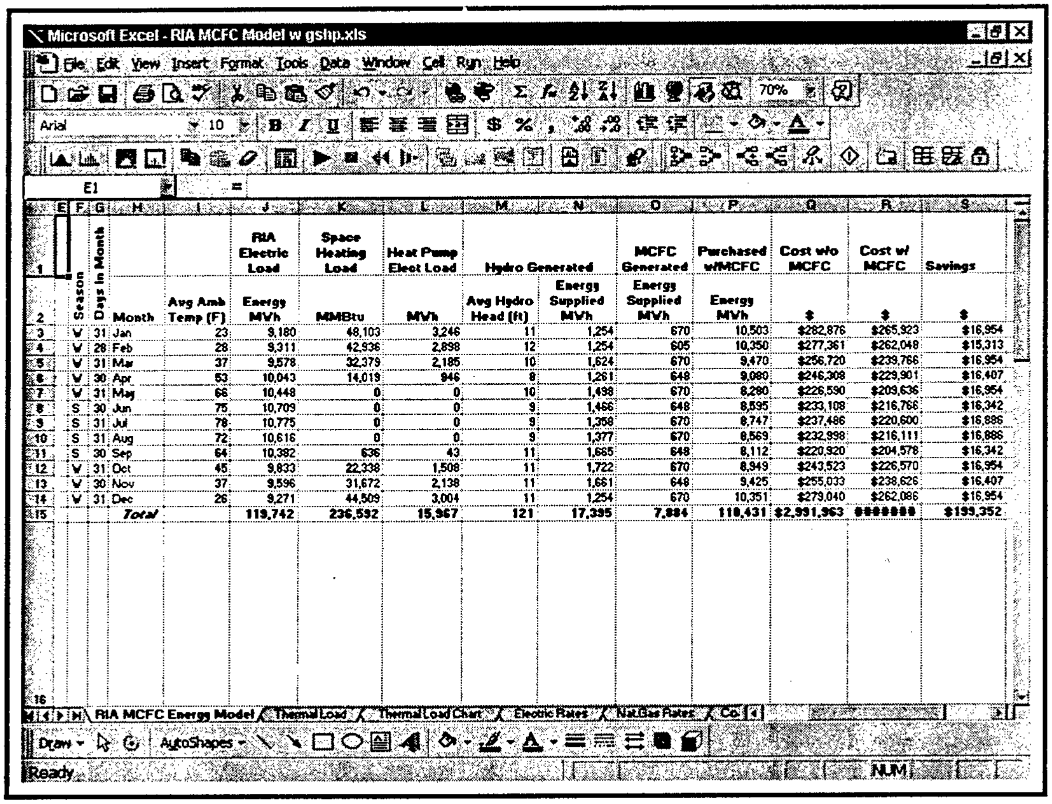
Date	Season	Electrical Consumption							Coal Consumption							Weather Conditions			Natural Gas Consumption		
		Mega Watt-Hours Purchased	Mega Watt-Hours Generated	Total Usage	Average River Head	Purchased Peak Demand	Total Peak Demand	Hydro-Electric Demand	Coal Consumption	Btu/LB Content	Steam Produced	>=65F	<65F	KLBS Steam Produced/MMBtu Consumed	Coal Unit Cost	Avg Temperature	Heating Degree Days	Cooling Degree Days	Month's Bill (Purchased)	Total Gas Purchased	Gas Unit Cost
		MWH/ Month	MWH/ Month	MWH/ Month	ft	kW	kW	kW	MMBtu/ Month	Btu/lb	klbs/ Month			klbs/ MMBtu	$/klbs	°F	HDD/ Month	CDD/ Month	$/Month	MMBtu/ Month	$/ MMBtu
Sep-95	Summer	7,196	1,445	8,641	11.20	17,035	18,662	1,627	31,815	12,496	24,319		24,319	0.764	2.408	62.2	146	69	$2,429	723	$3.36
Oct-95	Winter	6,944	1,445	8,389	10.50	17,035	19,675	2,640	41,437	12,496	31,535		31,535	0.761	2.419	55.6	298	15	$4,698	1,134	$4.14
Nov-95	Winter	6,538	1,450	7,988	10.79	16,493	18,239	1,746	60,681	12,496	46,125		46,125	0.760	2.421	43.6	637	1	$8,734	2,310	$3.78
Dec-95	Winter	6,832	1,740	8,572	11.23	15,800	18,469	2,669	84,698	12,496	62,576		62,576	0.739	2.491	33.3	973	0	$12,646	3,189	$3.97
Jan-96	Winter	6,412	1,493	7,905	11.60	17,993	18,678	685	104,547	12,596	78,952		78,952	0.755	2.463	20.1	1,385	0	$15,544	4,667	$3.33
Feb-96	Winter	6,412	1,099	7,511	10.85	16,884	17,430	546	95,704	12,596	72,200		72,200	0.754	2.465	25.2	1,147	0	$18,166	4,569	$3.98
Mar-96	Winter	6,692	1,114	7,806	10.34	16,342	16,977	635	92,429	12,596	69,791		69,791	0.755	2.463	32.6	995	0	$15,832	4,008	$3.95
Apr-96	Winter	5,964	895	6,859	8.47	16,355	17,668	1,313	61,292	12,596	46,101		46,101	0.752	2.473	47.4	519	0	$14,697	3,058	$4.81
May-96	Winter	7,308	691	7,999	7.10	17,275	18,409	1,134	48,066	12,596	36,222		36,222	0.754	2.468	58.1	253	46	$7,925	1,788	$4.43
Jun-96	Summer	7,294	823	8,117	7.96	18,131	19,200	1,069	32,901	12,596	24,825	24,825		0.755	2.465	70.8	27	208	$4,140	1,363	$3.04
Jul-96	Summer	7,406	1,214	8,620	10.37	17,879	17,952	73	32,170	12,596	24,266	24,266		0.754	2.465	72.1	0	229	$5,665	1,150	$4.93
Aug-96	Summer	7,742	1,382	9,124	11.66	17,690	19,370	1,680	33,757	12,596	25,177	25,177		0.746	2.494	72.9	0	253	$6,080	1,327	$4.58
Sep-96	Summer	6,048	1,397	7,445	12.26	16,355	18,101	1,746	32,674	12,596	24,741		24,741	0.757	2.456	59.0	81	69	$4,803	1,117	$4.30
Oct-96	Winter	6,902	1,346	8,248	10.50	17,300	18,631	1,331	41,315	12,596	31,204		31,204	0.755	2.462	52.5	385	6	$4,237	1,229	$3.45
Nov-96	Winter	6,356	1,250	7,606	9.72	16,771	18,345	1,574	85,779	12,596	64,168		64,168	0.748	2.486	32.2	975	0	$13,827	4,124	$3.35
Dec-96	Winter	6,538	1,354	7,892	11.75	17,312	18,678	1,366	98,224	12,596	74,059		74,059	0.754	2.467	25.9	1,206	0	$16,807	4,757	$3.53
Jan-97	Winter	6,482	1,125	7,607	10.64	16,443	17,041	598	105,138	12,775	78,684		78,684	0.748	2.427	17.2	1,474	0	$37,733	6,466	$5.84
Feb-97	Winter	5,894	886	6,780	10.79	16,456	17,129	673	86,666	12,775	64,812		64,812	0.748	2.428	29.0	1,000	0	$23,886	5,270	$4.53
Mar-97	Winter	6,104	910	7,014	10.72	16,153	17,106	953	81,045	12,775	60,232		60,232	0.743	2.444	40.3	757	0	$15,257	1,543	$9.89
Apr-97	Winter	6,860	394	7,254	6.20	17,262	17,497	235	64,693	12,775	48,373		48,373	0.748	2.429	46.9	537	1	$15,984	4,800	$3.33
May-97	Winter	6,510	799	7,309	8.80	16,745	17,478	733	40,625	12,775	30,421		30,421	0.749	2.425	56.1	277	11	$11,371	3,641	$3.12
Jun-97	Summer	6,552	1,090	7,642	11.37	17,741	18,576	835	31,069	12,775	23,229	23,229		0.748	2.429	71.2	4	196	$11,849	3,794	$3.12

Date	Season	Electrical Consumption: Mega Watt-Hours Purchased	Electrical Consumption: Mega Watt-Hours Generated	Electrical Consumption: Total Usage	Electrical Consumption: Average River Head	Electrical Consumption: Purchased Peak Demand	Electrical Consumption: Total Peak Demand	Electrical Consumption: Hydro-Electric Demand	Coal Consumption: Coal Consumption	Coal Consumption: Btu/LB Content	Coal Consumption: Steam Produced	Coal Consumption: >=65F	Coal Consumption: <65F	Coal Consumption: KLBS Steam Produced/MMBtu Consumed	Coal Consumption: Coal Unit Cost	Weather Conditions: Avg Temperature	Weather Conditions: Heating Degree Days	Weather Conditions: Cooling Degree Days	Natural Gas Consumption: Month's Bill (Purchased)	Natural Gas Consumption: Total Gas Purchased	Natural Gas Consumption: Gas Unit Cost
		MWH/ Month	MWH/ Month	MWH/ Month	ft	kW	kW	kW	MMBtu/ Month	Btu/lb	klbs/ Month			klbs/ MMBtu	$/klbs	°F	HDD/ Month	CDD/ Month	$/Month	MMBtu/ Month	$/ MMBtu
Jul-97	Summer	7,252	1,003	8,255	10.62	17,287	17,482	195	30,021	12,775	22,393	22,393		0.746	2.435	74.8	5	315	$5,424	1,475	$3.68
Aug-97	Summer	6,930	910	7,840	10.89	16,632	17,469	837	26,751	12,775	19,241	19,241		0.719	2.525	70.7	2	186	$4,500	1,254	$3.59
Sep-97	Summer	6,216	552	6,768	12.07	17,627	17,475		25,524	12,775	18,535	18,535		0.726	2.501	65.7	61	87	$3,931	1,065	$3.69
Oct-97	Winter	6,230	1,366	7,596	11.80	16,090	17,566	1,476	43,767	12,775	32,600		32,600	0.745	2.438	53.4	356	6	$6,573	1,595	$4.12
Nov-97	Winter	5,768	1,145	6,913	10.87	14,679	16,327	1,648	82,271	12,775	61,396		61,396	0.746	2.434	32.6	966	0	$15,013	3,302	$4.55
Dec-97	Winter	5,852	1,152	7,004	10.89	15,687	16,149	462	95,072	12,775	90,106		90,106	0.948	1.916	24.8	1,238	0	$21,161	3,948	$5.36
Jan-98	Winter	5,768	694	6,462	12.32	15,485	16,282	797	89,704	13,027	65,555		65,555	0.731	2.437	27.1	1,169	0	$21,829	4,336	$5.03
Feb-98	Winter	5,516	497	6,013	12.35	15,411	15,926	515	70,815	13,027	51,932		51,932	0.733	2.428	37.7	758	0	$24,214	6,235	$3.88
Mar-98	Winter	5,964	689	6,653	10.11	15,487	15,997	510	75,036	13,027	54,997		54,997	0.733	2.430	38.7	819	0	$14,540	4,310	$3.37
Apr-98	Winter	6,286	382	6,668	6.20	16,166	16,122		51,014	13,027	37,404		37,404	0.733	2.429	51.0	414	0	$19,910	5,267	$3.78
May-98	Winter	5,866	1,192	7,058	10.60	16,808	16,676		31,239	13,027	22,856	22,856		0.732	2.434	66.5	57	109	$4,809	1,323	$3.63
Jun-98	Summer	6,342	1,056	7,398	10.34	16,997			28,920	13,027	21,134	21,134		0.731	2.437	69.6	53	192	$4,809	1,323	$3.63
Jul-98	Summer	7,420	876	8,296	9.70		17,300		28,581	13,027	20,892	20,892		0.731	2.436	72.1	0	219	$3,311	958	$3.46
Aug-98	Summer	6,300	1,243	7,543	12.48	16,481	18,152	1,671	25,585	13,027	18,704	18,704		0.731	2.436	74.4	0	297	$2,982	779	$3.83
Sep-98	Summer	6,048	1,171	7,219	13.00	16,040	17,666	1,626	25,351	13,027	18,579	18,579		0.733	2.430	71.7	29	173	$2,047	596	$3.43
Oct-98	Winter	6,398	588	6,986	12.42	15,410	15,792	382	38,444	12,755	28,728		28,728	0.747	2.434	54.1	395	66	$3,838	947	$4.05
Nov-98	Winter	5,040	554	5,594	12.36	15,271	15,556	285	63,979	12,755	47,865		47,865	0.748	2.431	36.7	838	0	$8,837	1,878	$4.71
Dec-98	Winter	5,684	730	6,414	13.12	15,322	16,088	766	74,693	12,755	55,932		55,932	0.749	2.429	28.9	1,110	0	$22,081	4,386	$5.03
Jan-99	Winter	5,081	1,037	6,118	11.20	13,810			103,259	13,094	75,298		75,298	0.729	2.182	19.9	1,390	0	$19,658	5,928	$3.32
Feb-99	Winter	4,858	1,018	5,876	11.50	13,016			81,026	13,094	59,085		59,085	0.729	2.182	34.9	837	0	$23,587	8,230	$2.87
Mar-99	Winter	5,188	1,133	6,321	11.40	13,154			81,235	13,094	59,173		59,173	0.728	2.184	36.8	869	0	$13,073	4,380	$2.98
Apr-99	Winter	5,656	703	6,359	8.50	12,877			53,214	13,094	38,714		38,714	0.728	2.187	52.3	376	2	$7,257	3,540	$2.05

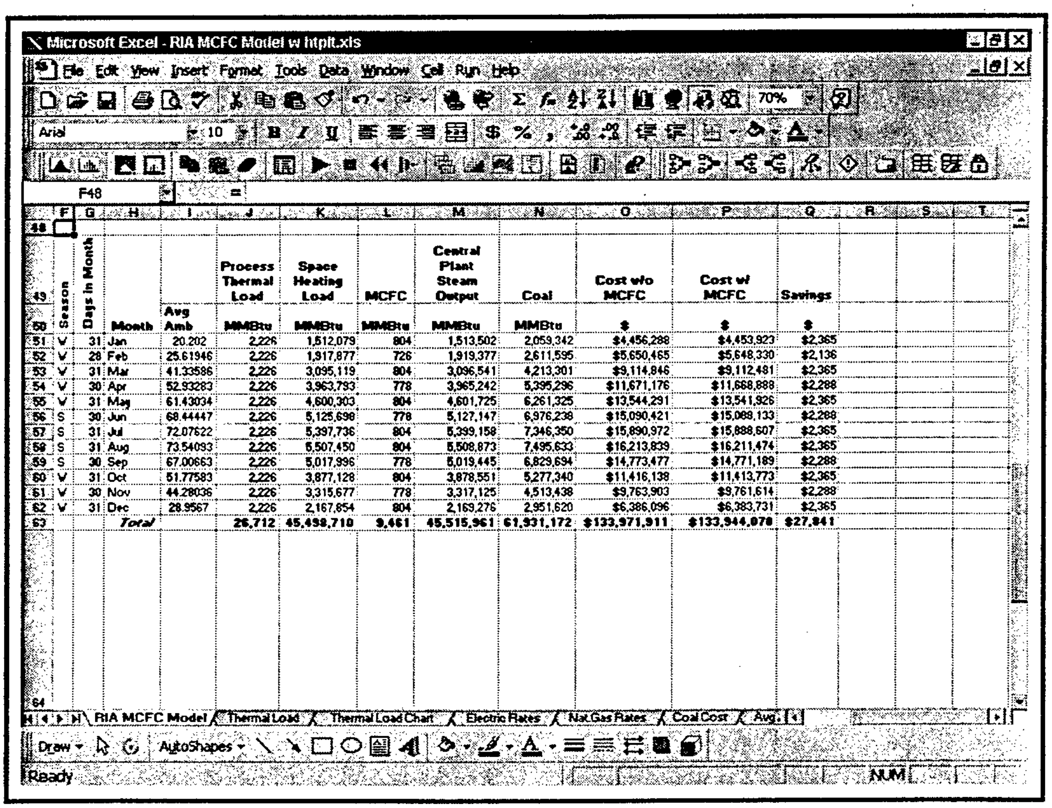
		Electrical Consumption							Coal Consumption							Weather Conditions			Natural Gas Consumption		
Date	Season	Mega Watt-Hours Purchased	Mega Watt-Hours Generated	Total Usage	Average River Head	Purchased Peak Demand	Total Peak Demand	Hydro-Electric Demand	Coal Consumption	Btu/LB Content	Steam Produced	>=65F	<65F	KLBS Steam Produced/MMBtu Consumed	Coal Unit Cost	Avg Temperature	Heating Degree Days	Cooling Degree Days	Month's Bill (Purchased)	Total Gas Purchased	Gas Unit Cost
		MWH/ Month	MWH/ Month	MWH/ Month	ft	kW	kW	kW	MMBtu/ Month	Btu/lb	klbs/ Month			klbs/ MMBtu	$/klbs	°F	HDD/ Month	CDD/ Month	$/Month	MMBtu/ Month	$/ MMBtu
May-99	Winter	5,338	624	5,962	7.70	14,616			32,054	13,094	23,095		23,095	0.721	2.208	63.4	103	61	$6,958	1,482	$4.70
Jun-99	Summer	5,982	742	6,724	8.64	14,099			27,785	13,094	20,211	20,211		0.727	2.188	71.6	18	223	$4,398	1,500	$2.93
Jul-99	Summer	6,463	934	7,397	10.00	15,095			29,147	13,094	21,201	21,201		0.727	2.188	79.0	0	440	$2,605	1,023	$2.55
Aug-99	Summer	5,759	1,006	6,765	10.52	13,936			31,504	13,094	22,825	22,825		0.725	2.196	71.0	2	192	$3,589	1,023	$3.51
Sep-99	Summer	5,071	1,051	6,122	11.74	13,570			29,514	13,094	21,374		21,374	0.724	2.197	63.3	129	83	$2,750	750	$3.67
Oct-99	Winter	5,418	1,190	6,608	12.10	14,099			37,856	13,027	27,472		27,472	0.726	2.204	54.2	333	4	$1,538	491	$3.13
Nov-99	Winter	4,558	1,078	5,636	11.82	13,054			62,511	13,094	46,176		46,176	0.739	2.154	43.5	638	0	$4,322	1,385	$3.12
Dec-99	Winter	5,582	1,075	6,657	12.40	13,482			78,224	13,094	57,069		57,069	0.730	2.181	32.7	993	0	$13,928	4,458	$3.12

Appendix D: RIA/MCFC Model Screen Shots

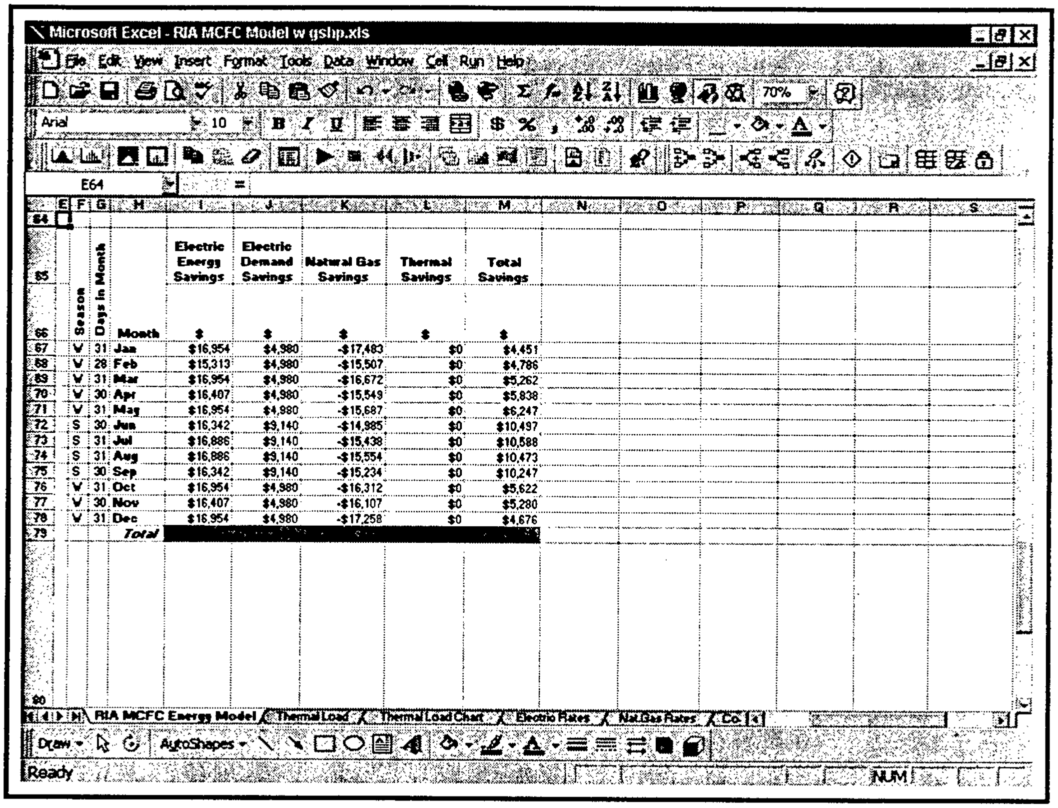




Season	Days In Month	Month	Avg Amb Temp (F)	RIA Electric Load Energy MWh	Space Heating Load MMBtu	Heat Pump Elect Load MWh	Hydro Generated Avg Hydro Head (ft)	Hydro Generated Energy Supplied MWh	MCFC Generated Energy Supplied MWh	Purchased w/MCFC Energy MWh	Cost w/o MCFC $	Cost w/ MCFC $	Savings $
W	31	Jan	23	9,180	48,103	3,246	11	1,254	670	10,503	$282,876	$265,923	$16,954
W	28	Feb	28	9,311	42,936	2,898	12	1,254	605	10,350	$277,361	$262,048	$15,313
W	31	Mar	37	9,578	32,379	2,185	10	1,624	670	9,470	$256,720	$239,766	$16,954
W	30	Apr	53	10,043	14,019	946	8	1,261	648	9,080	$246,308	$229,901	$16,407
W	31	May	66	10,448	0	0	10	1,498	670	8,280	$226,590	$209,636	$16,954
S	30	Jun	75	10,709	0	0	9	1,466	648	8,595	$233,108	$216,766	$16,342
S	31	Jul	78	10,775	0	0	9	1,358	670	8,747	$237,486	$220,600	$16,886
S	31	Aug	72	10,616	0	0	9	1,377	670	8,569	$232,998	$216,111	$16,886
S	30	Sep	64	10,382	636	43	11	1,665	648	8,112	$220,920	$204,578	$16,342
W	31	Oct	45	9,833	22,338	1,508	11	1,722	670	8,949	$243,523	$226,570	$16,954
W	30	Nov	37	9,596	31,672	2,138	11	1,661	648	9,425	$255,033	$238,626	$16,407
W	31	Dec	26	9,271	44,509	3,004	11	1,254	670	10,351	$279,040	$262,086	$16,954
		Total		119,742	236,592	15,967	121	17,395	7,884	110,431	$2,991,963	#######	$199,352

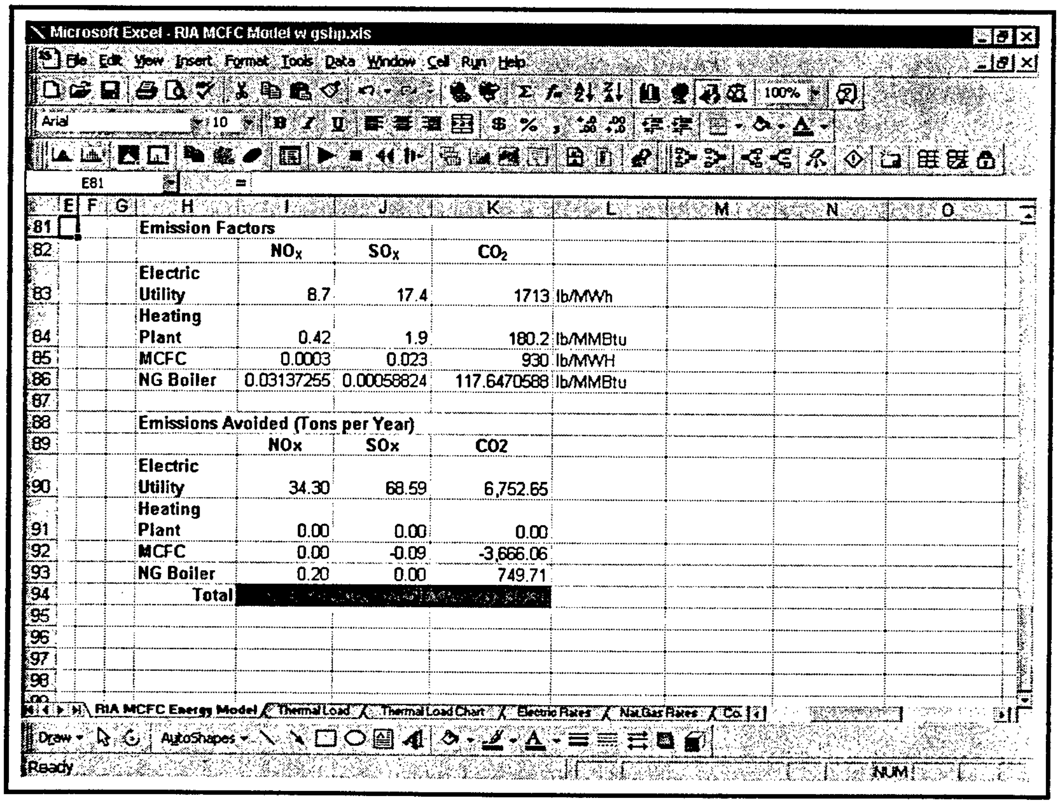


Season	Days in Month	Month	Avg Amb	Process Thermal Load MMBtu	Space Heating Load MMBtu	MCFC MMBtu	Central Plant Steam Output MMBtu	Coal MMBtu	Cost w/o MCFC $	Cost w/ MCFC $	Savings $
V	31	Jan	20.202	2,226	1,512,079	804	1,513,502	2,059,342	$4,456,288	$4,453,923	$2,365
V	28	Feb	25.61946	2,226	1,917,877	726	1,919,377	2,611,595	$5,650,465	$5,648,330	$2,136
V	31	Mar	41.33586	2,226	3,095,119	804	3,096,541	4,213,301	$9,114,846	$9,112,481	$2,365
V	30	Apr	52.93283	2,226	3,963,793	778	3,965,242	5,395,296	$11,671,176	$11,668,888	$2,288
V	31	May	61.43034	2,226	4,600,303	804	4,601,725	6,261,325	$13,544,291	$13,541,926	$2,365
S	30	Jun	68.44447	2,226	5,125,698	778	5,127,147	6,976,238	$15,090,421	$15,088,133	$2,288
S	31	Jul	72.07622	2,226	5,397,736	804	5,399,158	7,346,350	$15,890,972	$15,888,607	$2,365
S	31	Aug	73.54093	2,226	5,507,450	804	5,508,873	7,495,633	$16,213,839	$16,211,474	$2,365
S	30	Sep	67.00663	2,226	5,017,996	778	5,019,445	6,829,694	$14,773,477	$14,771,189	$2,288
V	31	Oct	51.77583	2,226	3,877,128	804	3,878,551	5,277,340	$11,416,138	$11,413,773	$2,365
V	30	Nov	44.28036	2,226	3,315,677	778	3,317,125	4,513,438	$9,763,903	$9,761,614	$2,288
V	31	Dec	28.9567	2,226	2,167,854	804	2,169,276	2,951,620	$6,386,096	$6,383,731	$2,365
		Total		26,712	45,458,710	9,461	45,515,961	61,931,172	$133,971,911	$133,944,070	$27,841



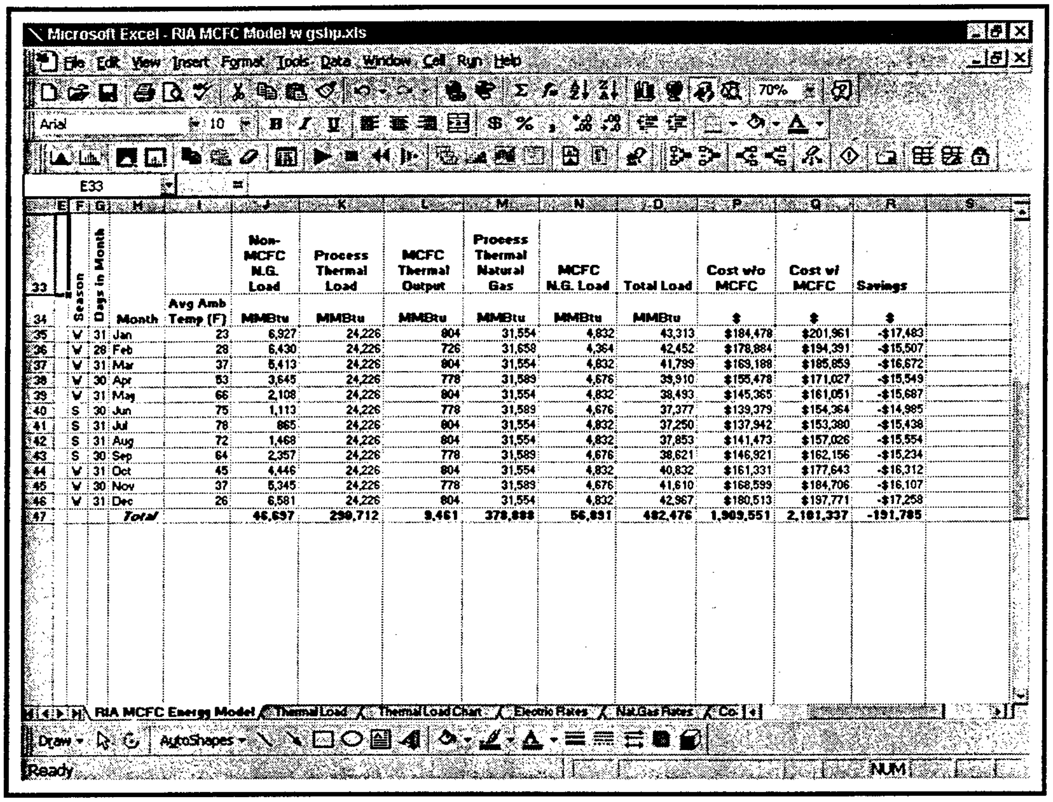
Microsoft Excel - RIA MCFC Model w gshp.xls

Season	Days in Month	Month	Electric Energy Savings $	Electric Demand Savings $	Natural Gas Savings $	Thermal Savings $	Total Savings $
V	31	Jan	$16,954	$4,980	-$17,483	$0	$4,451
V	28	Feb	$15,313	$4,980	-$15,507	$0	$4,786
V	31	Mar	$16,954	$4,980	-$16,672	$0	$5,262
V	30	Apr	$16,407	$4,980	-$15,549	$0	$5,838
V	31	May	$16,954	$4,980	-$15,687	$0	$6,247
S	30	Jun	$16,342	$9,140	-$14,985	$0	$10,497
S	31	Jul	$16,886	$9,140	-$15,438	$0	$10,588
S	31	Aug	$16,886	$9,140	-$15,554	$0	$10,473
S	30	Sep	$16,342	$9,140	-$15,234	$0	$10,247
V	31	Oct	$16,954	$4,980	-$16,312	$0	$5,622
V	30	Nov	$16,407	$4,980	-$16,107	$0	$5,280
V	31	Dec	$16,954	$4,980	-$17,258	$0	$4,676
		Total	[redacted]				



Microsoft Excel - RIA MCFC Model w gshp.xls

Emission Factors				
	NO_X	SO_X	CO_2	
Electric Utility	8.7	17.4	1713	lb/MWh
Heating Plant	0.42	1.9	180.2	lb/MMBtu
MCFC	0.0003	0.023	930	lb/MWH
NG Boiler	0.03137255	0.00058824	117.6470588	lb/MMBtu
Emissions Avoided (Tons per Year)				
	NOx	SOx	CO2	
Electric Utility	34.30	68.59	6,752.65	
Heating Plant	0.00	0.00	0.00	
MCFC	0.00	-0.09	-3,666.06	
NG Boiler	0.20	0.00	749.71	
Total	[redacted]			



Row	Season	Days in Month	Month	Avg Amb Temp (F)	Non-MCFC N.G. Load MMBtu	Process Thermal Load MMBtu	MCFC Thermal Output MMBtu	Process Thermal Natural Gas MMBtu	MCFC N.G. Load MMBtu	Total Load MMBtu	Cost w/o MCFC $	Cost w/ MCFC $	Savings $
35	W	31	Jan	23	6,927	24,226	804	31,554	4,832	43,313	$184,478	$201,961	-$17,483
36	W	28	Feb	28	6,430	24,226	726	31,658	4,364	42,452	$178,884	$194,391	-$15,507
37	W	31	Mar	37	5,413	24,226	804	31,554	4,832	41,799	$169,188	$185,859	-$16,672
38	W	30	Apr	53	3,645	24,226	778	31,589	4,676	39,910	$155,478	$171,027	-$15,549
39	W	31	May	66	2,108	24,226	804	31,554	4,832	38,493	$145,365	$161,051	-$15,687
40	S	30	Jun	75	1,113	24,226	778	31,589	4,676	37,377	$139,379	$154,364	-$14,985
41	S	31	Jul	78	865	24,226	804	31,554	4,832	37,250	$137,942	$153,380	-$15,438
42	S	31	Aug	72	1,468	24,226	804	31,554	4,832	37,853	$141,473	$157,026	-$15,554
43	S	30	Sep	64	2,357	24,226	778	31,589	4,676	38,621	$146,921	$162,156	-$15,234
44	W	31	Oct	45	4,446	24,226	804	31,554	4,832	40,832	$161,331	$177,643	-$16,312
45	W	30	Nov	37	5,345	24,226	778	31,589	4,676	41,610	$168,599	$184,706	-$16,107
46	W	31	Dec	26	6,581	24,226	804	31,554	4,832	42,967	$180,513	$197,771	-$17,258
47			*Total*		46,697	290,712	9,461	378,888	56,891	482,476	1,909,551	2,181,337	-191,785

Appendix E: Stochastic Modeling Overview

Deterministic versus Stochastic Modeling

Analysis models can be generally described as analogs of real-world processes. They apply input(s) to a modeled process and generate output(s) as shown in Figure E1.

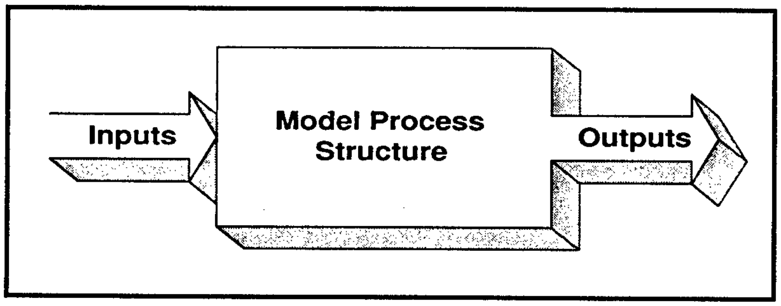


Figure E1: Fundamental process model.

Deterministic models apply discrete inputs resulting in discrete unique outputs. In other words each set of specific input values can only result in a specific set of output values. Change one or all of the inputs and different outputs will occur. Return the inputs to their original values and the previous output values are produced. With the same inputs the model produces the same outputs: a one-to-one mapping of inputs to outputs. Figure E2 illustrates a generic deterministic model.

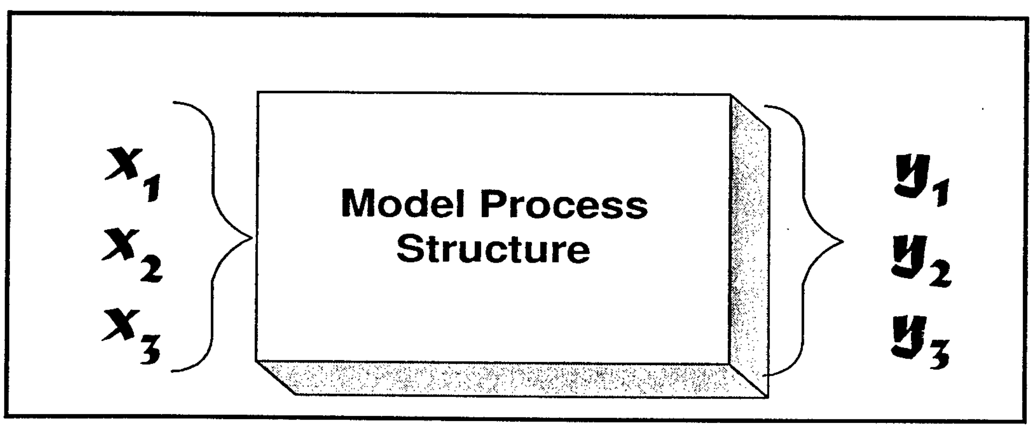


Figure E2. Generic deterministic model.

Stochastic models assume that some or all of the inputs are a range with an associated probability distribution as illustrated in Figure E3. For example, one input may be the cost of a raw material used to produce a product. Its unit cost is known to randomly fluctuate, over the period of interest, from a minimum to maximum value, but usually hovers around a typical value somewhere in-between. A second input could be the labor hours required to take the raw material and manufacture a finished product. Some craftspeople are faster than others so this input is also characterized as a minimum, maximum, and typical value distribution.

The output of a stochastic model is also reported as a distribution. An example of this is shown in Figure E4. The output distribution is generated from many iterations of the model using discrete input values sampled from the input distributions resulting in many discrete outputs. These discrete outputs are collected and plotted as a frequency (a.k.a. forecast) distribution.

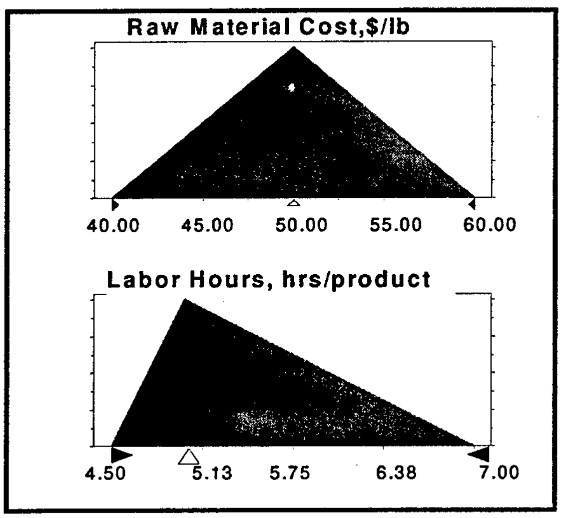


Figure E3. Example stochastic model inputs.

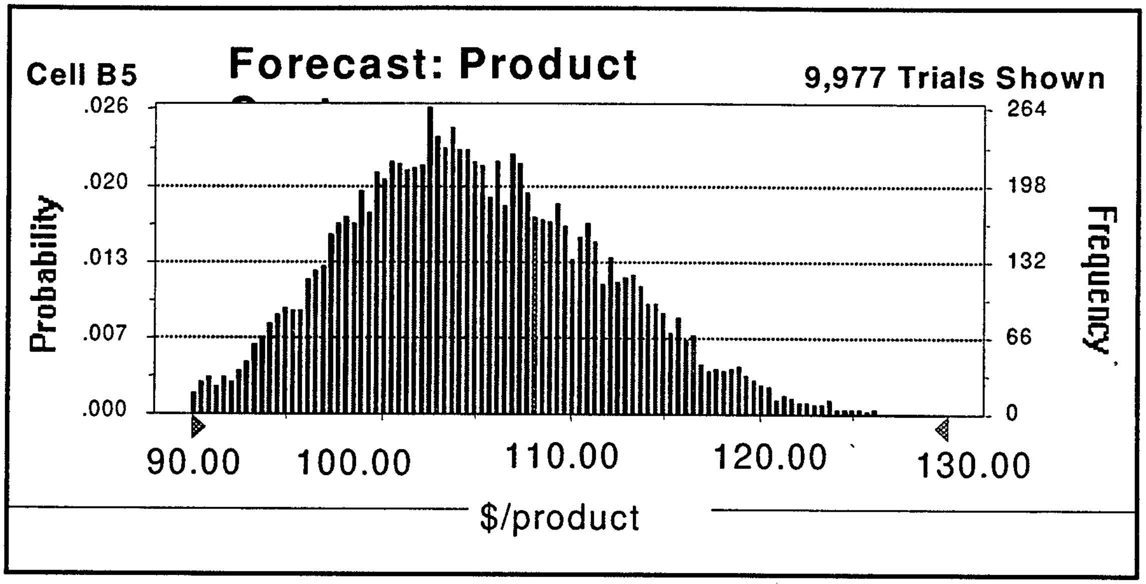


Figure E4. Example stochastic model output.

The advantage of stochastic modeling is the ability to provide inputs (a.k.a. assumptions) with variability that can account for the uncertainty of real-world processes. The resulting distribution forecast provides management an answer that is associated with probability of success or failure. Thus, this format provides results that can be used readily in risk-adjusted management decisions.

Depending on the features of the stochastic model software, it may be possible to obtain a sensitivity analysis such as the one illustrated in Figure E5. This analysis identifies the assumptions, which affect the forecast the most. This technique is very powerful because it permits management decisions on key controllable process variables (e.g., faster labor or lower material costs).

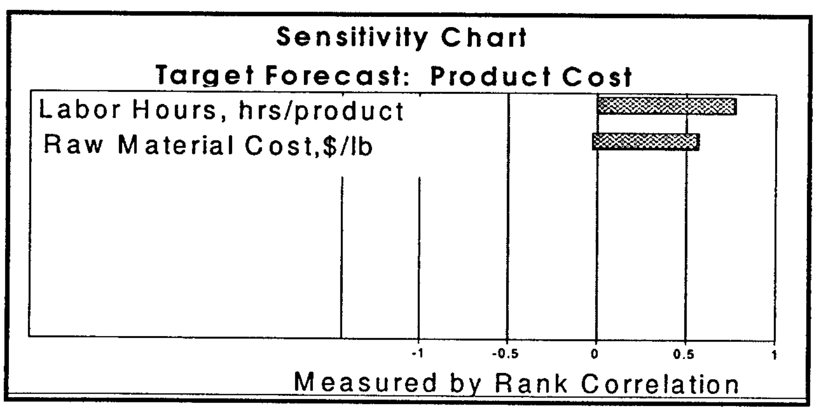
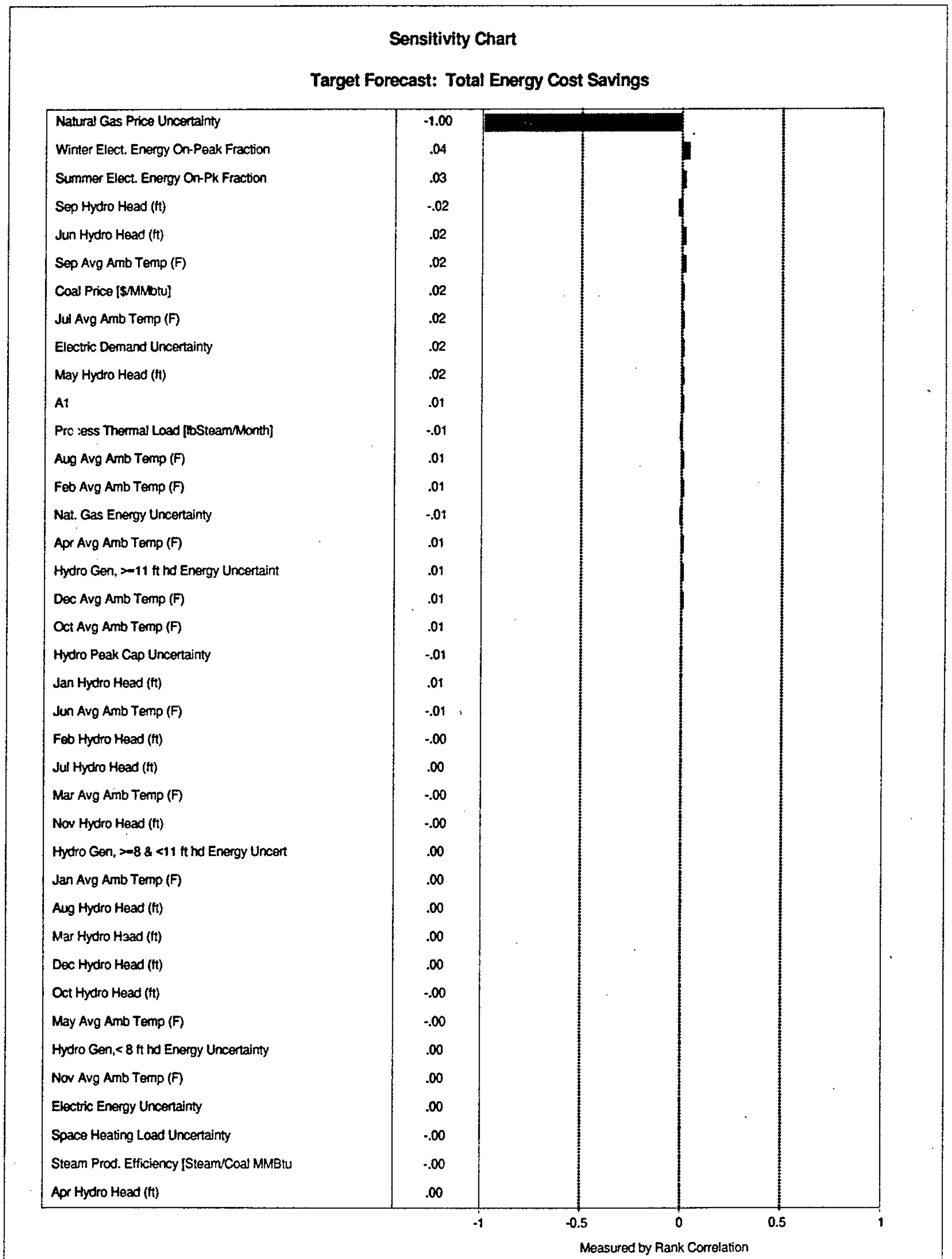


Figure E5. Example sensitivity analysis report.

Appendix F: Model with Central Heating Plant Results Report

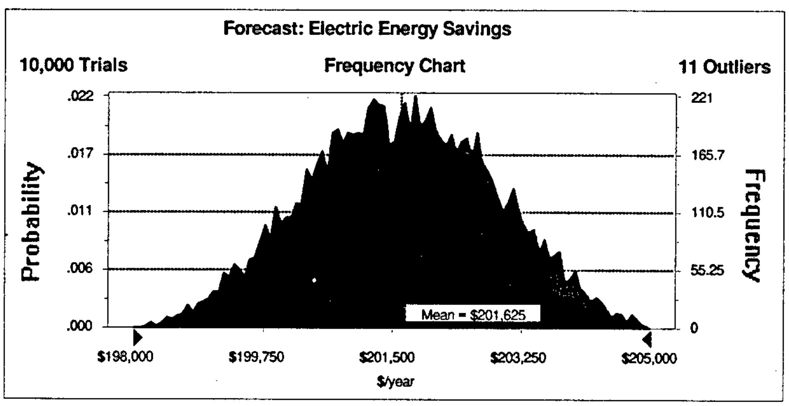
Crystal Ball Report
Simulation started on 2/14/00 at 14:34:16
Simulation stopped on 2/14/00 at 14:39:43



Forecast: Electric Energy Savings Cell: I79

Summary:
Display Range is from $198,000 to $205,000 $/year
Entire Range is from $197,876 to $205,307 $/year
After 10,000 Trials, the Std. Error of the Mean is $13

Statistics:	Value
Trials	10000
Mean	$201,625
Median	$201,627
Mode	---
Standard Deviation	$1,270
Variance	$1,612,509
Skewness	0.00
Kurtosis	2.56
Coeff. of Variability	0.01
Range Minimum	$197,876
Range Maximum	$205,307
Range Width	$7,432
Mean Std. Error	$12.70



Forecast: Electric Energy Savings (cont'd) Cell: I79

Percentiles:

Percentile	$/year
0%	$197,876
10%	$199,949
20%	$200,511
30%	$200,915
40%	$201,273
50%	$201,627
60%	$201,970
70%	$202,340
80%	$202,742
90%	$203,298
100%	$205,307

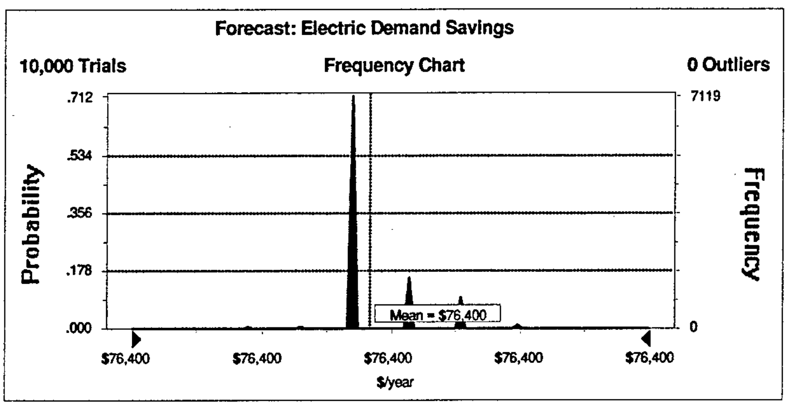
End of Forecast

Forecast: Electric Demand Savings Cell: J79

Summary:

Display Range is from $76,400 to $76,400 $/year
Entire Range is from $76,400 to $76,400 $/year
After 10,000 Trials, the Std. Error of the Mean is $0

Statistics:	Value
Trials	10000
Mean	$76,400
Median	$76,400
Mode	$76,400
Standard Deviation	$0
Variance	$0
Skewness	0.00
Kurtosis	+Infinity
Coeff. of Variability	0.00
Range Minimum	$76,400
Range Maximum	$76,400
Range Width	$0
Mean Std. Error	$0.00



Forecast: Electric Demand Savings (cont'd) Cell: J79

Percentiles:

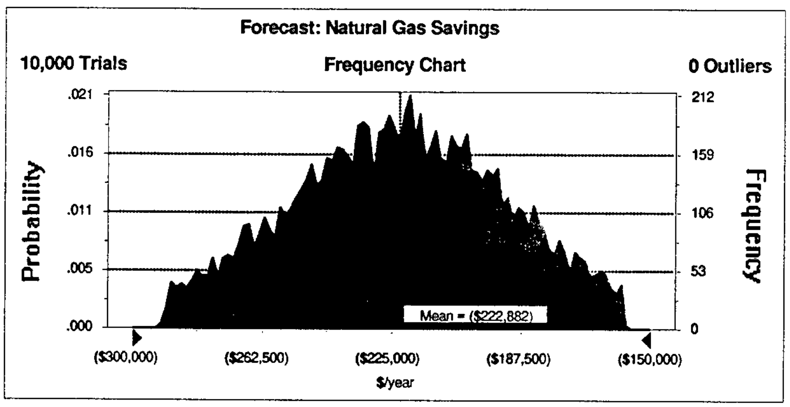
Percentile	$/year
0%	$76,400
10%	$76,400
20%	$76,400
30%	$76,400
40%	$76,400
50%	$76,400
60%	$76,400
70%	$76,400
80%	$76,400
90%	$76,400
100%	$76,400

End of Forecast

Forecast: Natural Gas Savings Cell: K79

Summary:
Display Range is from ($300,000) to ($150,000) $/year
Entire Range is from ($291,292) to ($157,070) $/year
After 10,000 Trials, the Std. Error of the Mean is $303

Statistics:	Value
Trials	10000
Mean	($222,882)
Median	($222,453)
Mode	---
Standard Deviation	$30,294
Variance	$917,700,360
Skewness	-0.04
Kurtosis	2.34
Coeff. of Variability	-0.14
Range Minimum	($291,292)
Range Maximum	($157,070)
Range Width	$134,222
Mean Std. Error	$302.94



Forecast: Natural Gas Savings (cont'd) Cell: K79

Percentiles:

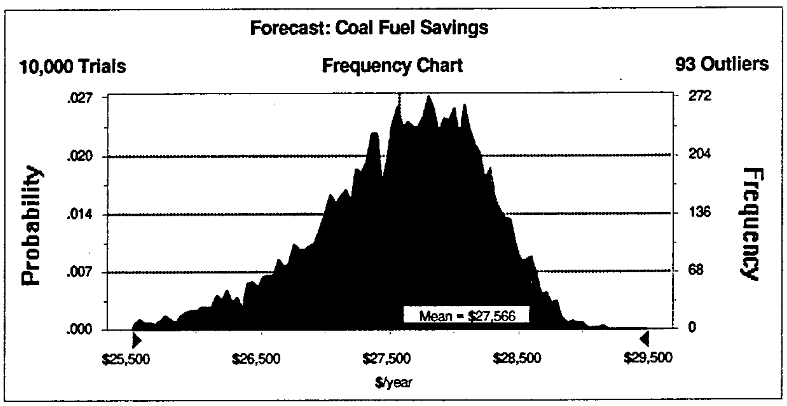
Percentile	$/year
0%	($291,292)
10%	($264,557)
20%	($250,039)
30%	($239,774)
40%	($231,120)
50%	($222,453)
60%	($214,458)
70%	($205,440)
80%	($195,443)
90%	($182,151)
100%	($157,070)

End of Forecast

Forecast: Coal Fuel Savings Cell: L79

Summary:
Display Range is from $25,500 to $29,500 $/year
Entire Range is from $23,948 to $29,238 $/year
After 10,000 Trials, the Std. Error of the Mean is $7

Statistics:	Value
Trials	10000
Mean	$27,566
Median	$27,652
Mode	---
Standard Deviation	$683
Variance	$466,596
Skewness	-0.82
Kurtosis	4.08
Coeff. of Variability	0.02
Range Minimum	$23,948
Range Maximum	$29,238
Range Width	$5,290
Mean Std. Error	$6.83



Forecast: Coal Fuel Savings (cont'd) Cell: L79

Percentiles:

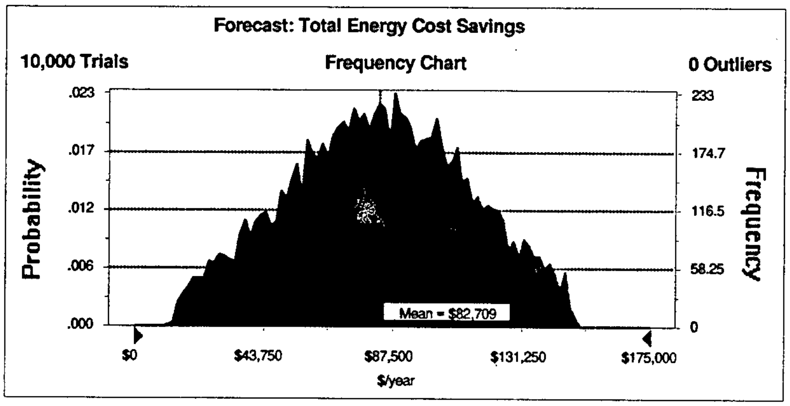
Percentile	$/year
0%	$23,948
10%	$26,660
20%	$27,046
30%	$27,291
40%	$27,488
50%	$27,652
60%	$27,813
70%	$27,975
80%	$28,138
90%	$28,351
100%	$29,238

End of Forecast

Forecast: Total Energy Cost Savings Cell: M79

Summary:
Display Range is from $0 to $175,000 $/year
Entire Range is from $11,639 to $150,286 $/year
After 10,000 Trials, the Std. Error of the Mean is $303

Statistics:	Value
Trials	10000
Mean	$82,709
Median	$83,049
Mode	---
Standard Deviation	$30,329
Variance	$919,866,387
Skewness	-0.04
Kurtosis	2.34
Coeff. of Variability	0.37
Range Minimum	$11,639
Range Maximum	$150,286
Range Width	$138,646
Mean Std. Error	$303.29



Forecast: Total Energy Cost Savings (cont'd) Cell: M79

Percentiles:

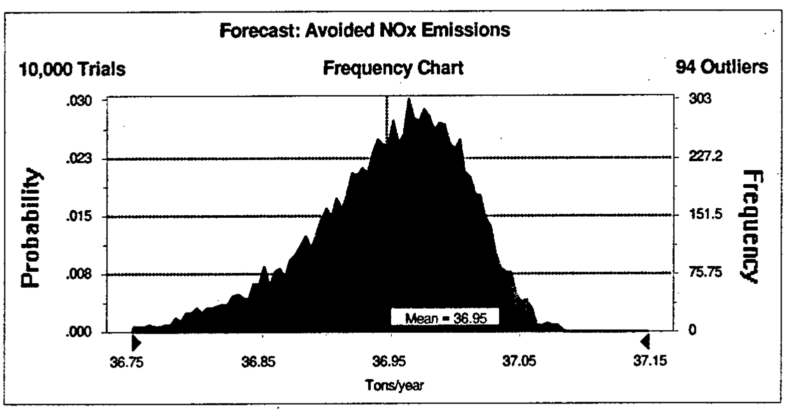
Percentile	$/year
0%	$11,639
10%	$41,259
20%	$55,390
30%	$65,818
40%	$74,697
50%	$83,049
60%	$91,180
70%	$100,290
80%	$110,011
90%	$123,474
100%	$150,286

End of Forecast

Forecast: Avoided NOx Emissions Cell: I92

Summary:
Display Range is from 36.75 to 37.15 Tons/year
Entire Range is from 36.61 to 37.11 Tons/year
After 10,000 Trials, the Std. Error of the Mean is 0.00

Statistics:	Value
Trials	10000
Mean	36.95
Median	36.96
Mode	---
Standard Deviation	0.06
Variance	0.00
Skewness	-0.89
Kurtosis	4.26
Coeff. of Variability	0.00
Range Minimum	36.61
Range Maximum	37.11
Range Width	0.49
Mean Std. Error	0.00



Forecast: Avoided NOx Emissions (cont'd) Cell: I92

Percentiles:

Percentile	Tons/year
0%	36.61
10%	36.86
20%	36.90
30%	36.92
40%	36.94
50%	36.96
60%	36.97
70%	36.98
80%	37.00
90%	37.02
100%	37.11

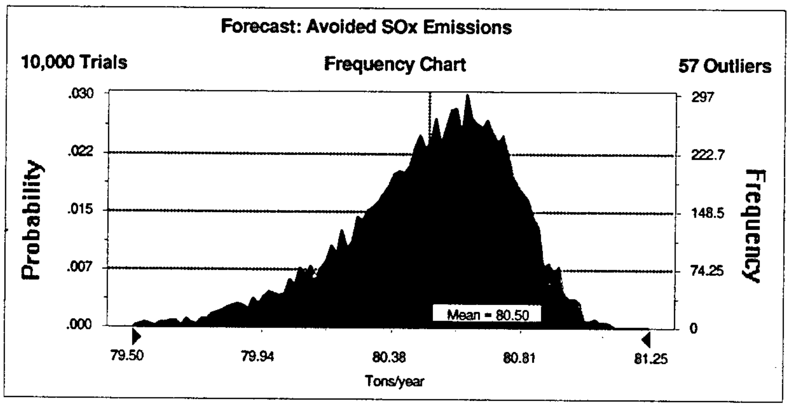
End of Forecast

Forecast: Avoided SOx Emissions Cell: J92

Summary:

Display Range is from 79.50 to 81.25 Tons/ year
Entire Range is from 78.99 to 81.22 Tons/ year
After 10,000 Trials, the Std. Error of the Mean is 0.00

Statistics:	Value
Trials	10000
Mean	80.50
Median	80.54
Mode	---
Standard Deviation	0.29
Variance	0.08
Skewness	-0.89
Kurtosis	4.26
Coeff. of Variability	0.00
Range Minimum	78.99
Range Maximum	81.22
Range Width	2.23
Mean Std. Error	0.00



Forecast: Avoided SOx Emissions (cont'd) Cell: J92

Percentiles:

Percentile	Tons/ year
0%	78.99
10%	80.11
20%	80.28
30%	80.39
40%	80.47
50%	80.54
60%	80.61
70%	80.67
80%	80.74
90%	80.83
100%	81.22

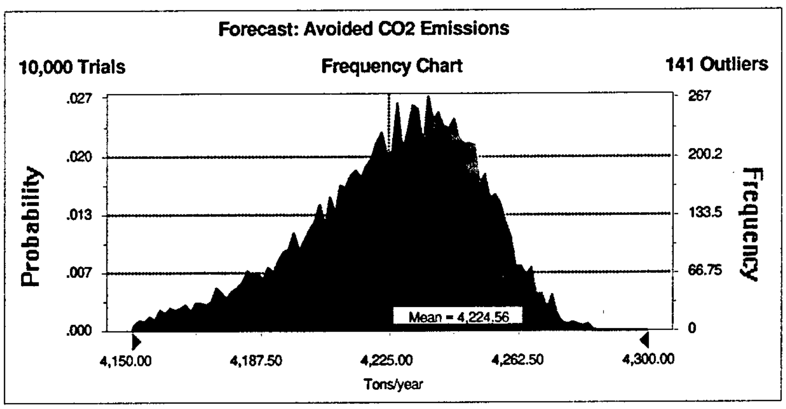
End of Forecast

Forecast: Avoided CO2 Emissions Cell: K92

Summary:

Display Range is from 4,150.00 to 4,300.00 Tons/ year
Entire Range is from 4,081.19 to 4,292.74 Tons/ year
After 10,000 Trials, the Std. Error of the Mean is 0.27

Statistics:	Value
Trials	10000
Mean	4,224.56
Median	4,228.52
Mode	---
Standard Deviation	27.37
Variance	749.16
Skewness	-0.89
Kurtosis	4.26
Coeff. of Variability	0.01
Range Minimum	4,081.19
Range Maximum	4,292.74
Range Width	211.55
Mean Std. Error	0.27



Forecast: Avoided CO2 Emissions (cont'd) Cell: K92

Percentiles:

Percentile	Tons/ year
0%	4,081.19
10%	4,187.75
20%	4,203.95
30%	4,213.90
40%	4,221.77
50%	4,228.52
60%	4,234.78
70%	4,240.96
80%	4,247.49
90%	4,255.53
100%	4,292.74

End of Forecast

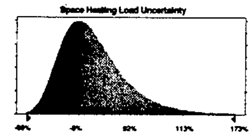
Assumptions

Assumption: Space Heating Load Uncertainty [RIA MCFC Model w htplt.xls]Thermal Load - Cell: F2

Extreme Value distribution with parameters:

Mode	-8%
Scale	30%

Selected range is from -Infinity to +Infinity
Mean value in simulation was 9%

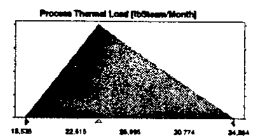


Assumption: Process Thermal Load [lbSteam/ Month] [RIA MCFC Model w htplt.xls]Thermal Load - Cell: A1

Triangular distribution with parameters:

Minimum	18,535	(=A32)
Likeliest	24,226	(=A33)
Maximum	34,854	(=A34)

Selected range is from 18,535 to 34,854
Mean value in simulation was 25,848



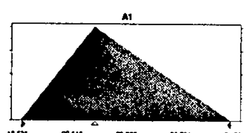
Assumption: A1 [RIA MCFC Model w htplt.xls]Thermal Load - Cell: A1

Triangular distribution with parameters:

Minimum	18,535	(=A32)
Likeliest	24,226	(=A33)
Maximum	34,854	(=A34)

Selected range is from 18,535 to 34,854
Mean value in simulation was 25,924

Assumption: A1 (cont'd) [RIA MCFC Model w htplt.xls]Thermal Load - Cell: A1

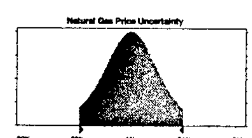


Assumption: Natural Gas Price Uncertainty [RIA MCFC Model w htplt.xls]Nat.Gas Rates - Cell: J2

Logistic distribution with parameters:

Mean	1%
Scale	10%

Selected range is from -29% to 31%
Mean value in simulation was 1%

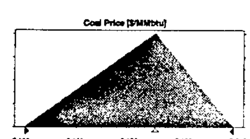


Assumption: Coal Price [$/ MMbtu] [RIA MCFC Model w htplt.xls]Coal Cost - Cell: G86

Triangular distribution with parameters:

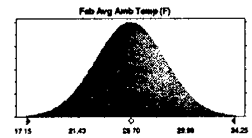
Minimum	2.150
Likeliest	2.188
Maximum	2.210

Selected range is from 2.150 to 2.210
Mean value in simulation was 2.183



Assumption: Feb Avg Amb Temp (F)

[RIA MCFC Model w htplt.xls]Avg Amb Temp - Cell: B3



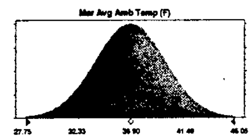
Normal distribution with parameters:

Mean	25.70
Standard Dev.	2.85

Selected range is from 17.15 to 34.25
Mean value in simulation was 25.69

Assumption: Mar Avg Amb Temp (F)

[RIA MCFC Model w htplt.xls]Avg Amb Temp - Cell: B4



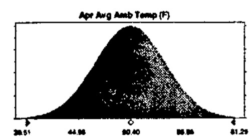
Normal distribution with parameters:

Mean	36.90
Standard Dev.	3.05

Selected range is from 27.75 to 46.05
Mean value in simulation was 36.85

Assumption: Apr Avg Amb Temp (F)

[RIA MCFC Model w htplt.xls]Avg Amb Temp - Cell: B5



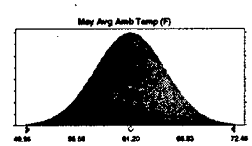
Normal distribution with parameters:

Mean	50.40
Standard Dev.	3.63

Selected range is from 39.50 to 61.30
Mean value in simulation was 50.38

Assumption: May Avg Amb Temp (F)

[RIA MCFC Model w htplt.xls]Avg Amb Temp - Cell: B6



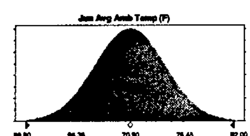
Normal distribution with parameters:

Mean	61.20
Standard Dev.	3.75

Selected range is from 49.95 to 72.45
Mean value in simulation was 61.18

Assumption: Jun Avg Amb Temp (F)

[RIA MCFC Model w htplt.xls]Avg Amb Temp - Cell: B7



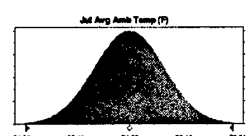
Normal distribution with parameters:

Mean	70.90
Standard Dev.	3.70

Selected range is from 59.80 to 82.00
Mean value in simulation was 70.88

Assumption: Jul Avg Amb Temp (F)

[RIA MCFC Model w htplt.xls]Avg Amb Temp - Cell: B8



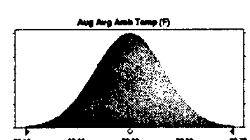
Normal distribution with parameters:

Mean	74.80
Standard Dev.	3.57

Selected range is from 64.10 to 85.50
Mean value in simulation was 74.71

Assumption: Aug Avg Amb Temp (F)

[RIA MCFC Model w htplt.xls]Avg Amb Temp - Cell: B9



Normal distribution with parameters:

Mean	72.90
Standard Dev.	3.60

Selected range is from 62.10 to 83.70
Mean value in simulation was 72.87

Assumption: Sep Avg Amb Temp (F)

[RIA MCFC Model w htplt.xls]Avg Amb Temp - Cell: B10

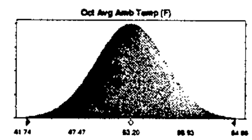
Assumption: Oct Avg Amb Temp (F)

[RIA MCFC Model w htplt.xls]Avg Amb Temp - Cell: B11

Normal distribution with parameters:

Mean	53.20
Standard Dev.	3.82

Selected range is from 41.75 to 64.65
Mean value in simulation was 53.19



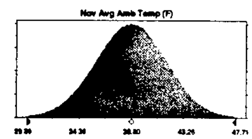
Assumption: Nov Avg Amb Temp (F)

[RIA MCFC Model w htplt.xls]Avg Amb Temp - Cell: B12

Normal distribution with parameters:

Mean	38.80
Standard Dev.	2.97

Selected range is from 29.90 to 47.70
Mean value in simulation was 38.72



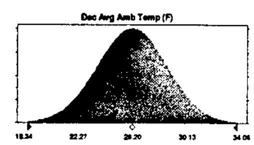
Assumption: Dec Avg Amb Temp (F)

[RIA MCFC Model w htplt.xls]Avg Amb Temp - Cell: B13

Normal distribution with parameters:

Mean	26.20
Standard Dev.	2.62

Selected range is from 18.35 to 34.05
Mean value in simulation was 26.18



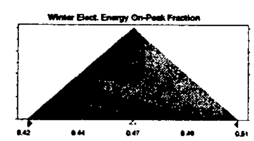
Assumption: Winter Elect. Energy On-Peak Fraction

[RIA MCFC Model w htplt.xls]RIA PWRSUMM - Cell: D104

Triangular distribution with parameters:

Minimum	0.42
Likeliest	0.47
Maximum	0.51

Selected range is from 0.42 to 0.51
Mean value in simulation was 0.47



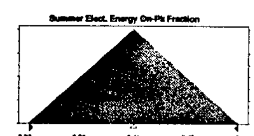
Assumption: Summer Elect. Energy On-Pk Fraction

[RIA MCFC Model w htplt.xls]RIA PWRSUMM - Cell: D105

Triangular distribution with parameters:

Minimum	0.37
Likeliest	0.41
Maximum	0.45

Selected range is from 0.37 to 0.45
Mean value in simulation was 0.41



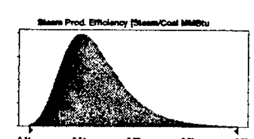
Assumption: Steam Prod. Efficiency [Steam/ Coal MMBtu

[RIA MCFC Model w htplt.xls]Coal Consumption - Cell: G4

Extreme Value distribution with parameters:

Mode	0.74
Scale	0.01

Selected range is from -Infinity to +Infinity
Mean value in simulation was 0.75



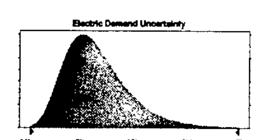
Assumption: Electric Demand Uncertainty

[RIA MCFC Model w htplt.xls]Electric Load - Cell: L2

Extreme Value distribution with parameters:

Mode	-2%
Scale	6%

Selected range is from -Infinity to +Infinity
Mean value in simulation was 1%

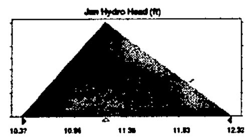


Assumption: Jan Hydro Head (ft)

[RIA MCFC Model w htplt.xls]Hydro Electric Gen. - Cell: O48

Triangular distribution with parameters:

Minimum	10.37
Likeliest	11.15
Maximum	12.32



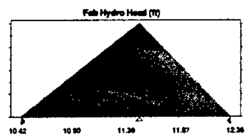
Selected range is from 10.37 to 12.32
Mean value in simulation was 11.29

Assumption: Feb Hydro Head (ft)

[RIA MCFC Model w htplt.xls]Hydro Electric Gen. - Cell: O49

Triangular distribution with parameters:

Minimum	10.42
Likeliest	11.51
Maximum	12.35



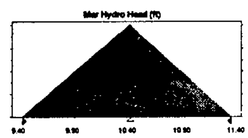
Selected range is from 10.42 to 12.35
Mean value in simulation was 11.43

Assumption: Mar Hydro Head (ft)

[RIA MCFC Model w htplt.xls]Hydro Electric Gen. - Cell: O50

Triangular distribution with parameters:

Minimum	9.40
Likeliest	10.43
Maximum	11.40



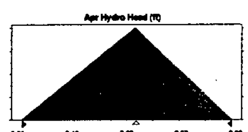
Selected range is from 9.40 to 11.40
Mean value in simulation was 10.41

Assumption: Apr Hydro Head (ft)

[RIA MCFC Model w htplt.xls]Hydro Electric Gen. - Cell: O51

Triangular distribution with parameters:

Minimum	5.26
Likeliest	7.72
Maximum	9.80



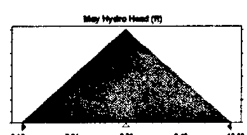
Selected range is from 5.26 to 9.80
Mean value in simulation was 7.59

Assumption: May Hydro Head (ft)

[RIA MCFC Model w htplt.xls]Hydro Electric Gen. - Cell: O52

Triangular distribution with parameters:

Minimum	6.12
Likeliest	8.34
Maximum	10.60



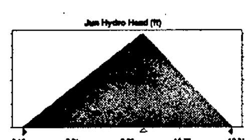
Selected range is from 6.12 to 10.60
Mean value in simulation was 8.35

Assumption: Jun Hydro Head (ft)

[RIA MCFC Model w htplt.xls]Hydro Electric Gen. - Cell: O53

Triangular distribution with parameters:

Minimum	6.18
Likeliest	9.71
Maximum	12.31



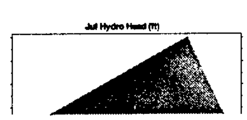
Selected range is from 6.18 to 12.31
Mean value in simulation was 9.40

Assumption: Jul Hydro Head (ft)

[RIA MCFC Model w htplt.xls]Hydro Electric Gen. - Cell: O54

Triangular distribution with parameters:

Minimum	4.80
Likeliest	9.73
Maximum	11.02



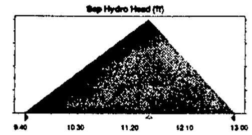
Assumption: Sep Hydro Head (ft)

[RIA MCFC Model w htplt.xls]Hydro Electric Gen. - Cell: Q56

Triangular distribution with parameters:

Minimum	9.40
Likeliest	11.53
Maximum	13.00

Selected range is from 9.40 to 13.00
Mean value in simulation was 11.32



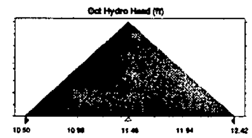
Assumption: Oct Hydro Head (ft)

[RIA MCFC Model w htplt.xls]Hydro Electric Gen. - Cell: Q57

Triangular distribution with parameters:

Minimum	10.50
Likeliest	11.45
Maximum	12.42

Selected range is from 10.50 to 12.42
Mean value in simulation was 11.45



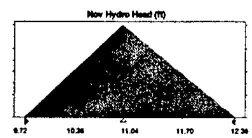
Assumption: Nov Hydro Head (ft)

[RIA MCFC Model w htplt.xls]Hydro Electric Gen. - Cell: Q58

Triangular distribution with parameters:

Minimum	9.72
Likeliest	10.96
Maximum	12.36

Selected range is from 9.72 to 12.36
Mean value in simulation was 11.01



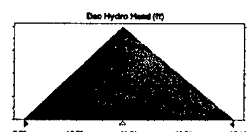
Assumption: Dec Hydro Head (ft)

[RIA MCFC Model w htplt.xls]Hydro Electric Gen. - Cell: Q59

Triangular distribution with parameters:

Minimum	9.89
Likeliest	11.41
Maximum	13.12

Selected range is from 9.89 to 13.12
Mean value in simulation was 11.47



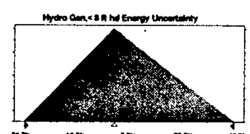
Assumption: Hydro Gen,< 8 ft hd Energy Uncertainty

[RIA MCFC Model w htplt.xls]Hydro Electric Gen. - Cell: T3

Triangular distribution with parameters:

Minimum	-35.7%
Likeliest	-2.3%
Maximum	42.3%

Selected range is from -35.7% to 42.3%
Mean value in simulation was 1.3%



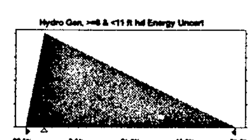
Assumption: Hydro Gen, >=8 & <11 ft hd Energy Uncert

[RIA MCFC Model w htplt.xls]Hydro Electric Gen. - Cell: T4

Triangular distribution with parameters:

Minimum	-28.5%
Likeliest	-19.8%
Maximum	71.6%

Selected range is from -28.5% to 71.6%
Mean value in simulation was 7.8%

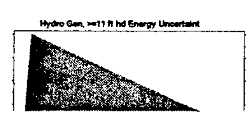


Assumption: Hydro Gen, >=11 ft hd Energy Uncertaint

[RIA MCFC Model w htplt.xls]Hydro Electric Gen. - Cell: T5

Triangular distribution with parameters:

Minimum	-37.9%
Likeliest	-30.8%
Maximum	171.1%

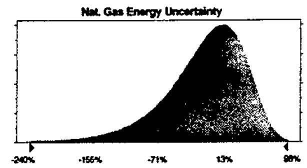


Assumption: Nat. Gas Energy Uncertainty

[RIA MCFC Model w htplt.xds]Natural Gas - Cell: E2

Extreme Value distribution with parameters:

Mode	13%
Scale	42%



Selected range is from -Infinity to +Infinity
Mean value in simulation was -12%

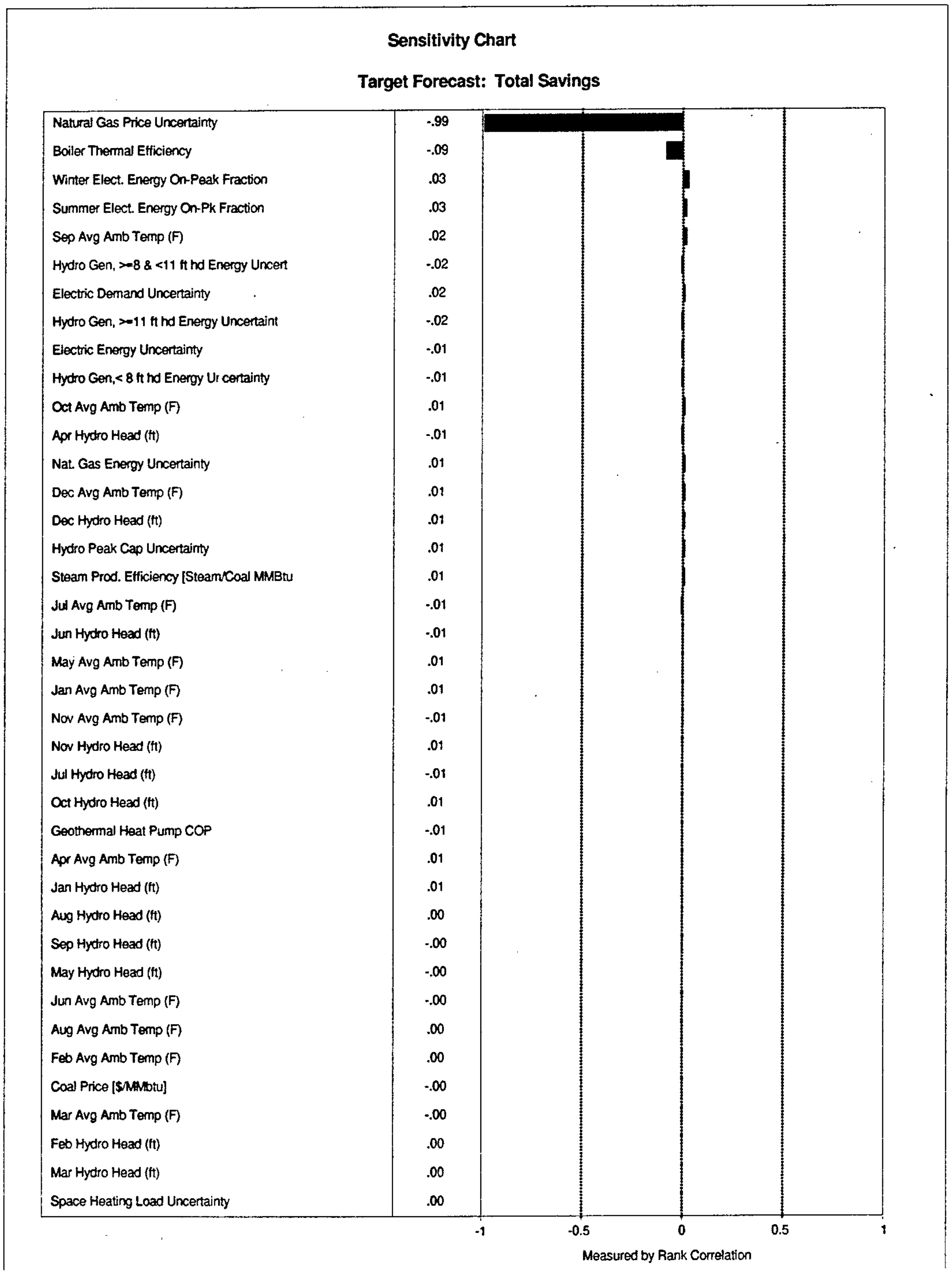
End of Assumptions

Appendix G: Model with Geothermal Heat Pumps Results Report

Crystal Ball Report

Simulation started on 2/14/00 at 14:21:14

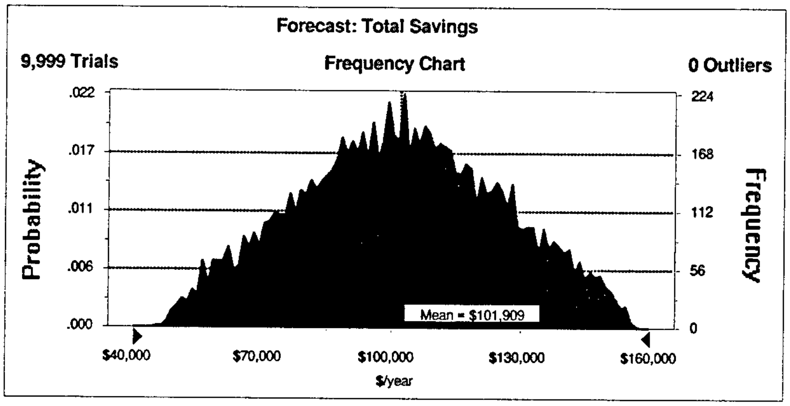
Simulation stopped on 2/14/00 at 14:25:51



Forecast: Total Savings Cell: M79

Summary:
Display Range is from $40,000 to $160,000 $/year
Entire Range is from $45,340 to $157,181 $/year
After 9,999 Trials, the Std. Error of the Mean is $238

Statistics:	Value
Trials	9999
Mean	$101,909
Median	$101,847
Mode	---
Standard Deviation	$23,699
Variance	$561,655,866
Skewness	0.01
Kurtosis	2.35
Coeff. of Variability	0.23
Range Minimum	$45,340
Range Maximum	$157,181
Range Width	$111,841
Mean Std. Error	$237.00



Forecast: Total Savings (cont'd) Cell: M79

Percentiles:

Percentile	$/year
0%	$45,340
10%	$69,925
20%	$80,610
30%	$88,635
40%	$95,449
50%	$101,847
60%	$108,205
70%	$115,113
80%	$123,582
90%	$134,137
100%	$157,181

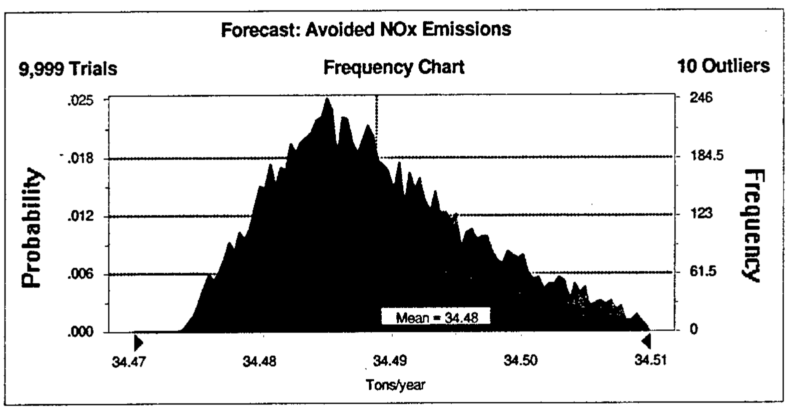
End of Forecast

Forecast: Avoided NOx Emissions Cell: I94

Summary:

Display Range is from 34.47 to 34.51 Tons/ year
Entire Range is from 34.47 to 34.51 Tons/ year
After 9,999 Trials, the Std. Error of the Mean is 0.00

Statistics:	Value
Trials	9999
Mean	34.48
Median	34.48
Mode	---
Standard Deviation	0.01
Variance	0.00
Skewness	0.51
Kurtosis	2.64
Coeff. of Variability	0.00
Range Minimum	34.47
Range Maximum	34.51
Range Width	0.04
Mean Std. Error	0.00



Forecast: Avoided NOx Emissions (cont'd) Cell: I94

Percentiles:

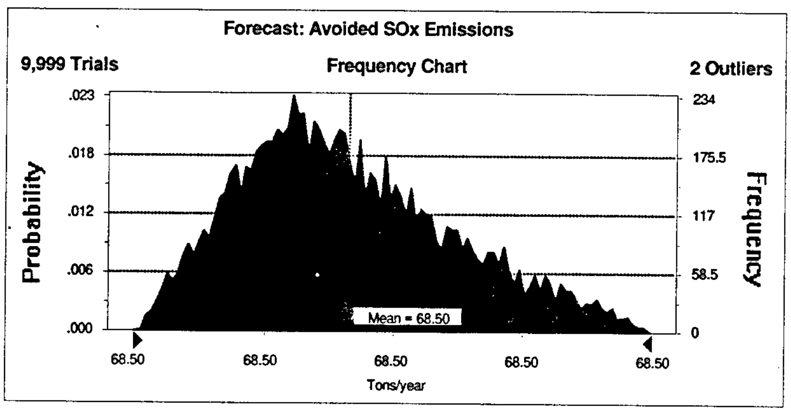
Percentile	Tons/ year
0%	34.47
10%	34.47
20%	34.48
30%	34.48
40%	34.48
50%	34.48
60%	34.48
70%	34.49
80%	34.49
90%	34.49
100%	34.51

End of Forecast

Forecast: Avoided SOx Emissions Cell: J94

Summary:
Display Range is from 68.50 to 68.50 Tons/ year
Entire Range is from 68.50 to 68.50 Tons/ year
After 9,999 Trials, the Std. Error of the Mean is 0.00

Statistics:	Value
Trials	9999
Mean	68.50
Median	68.50
Mode	---
Standard Deviation	0.00
Variance	0.00
Skewness	0.00
Kurtosis	+Infinity
Coeff. of Variability	0.00
Range Minimum	68.50
Range Maximum	68.50
Range Width	0.00
Mean Std. Error	0.00



Forecast: Avoided SOx Emissions (cont'd) Cell: J94

Percentiles:

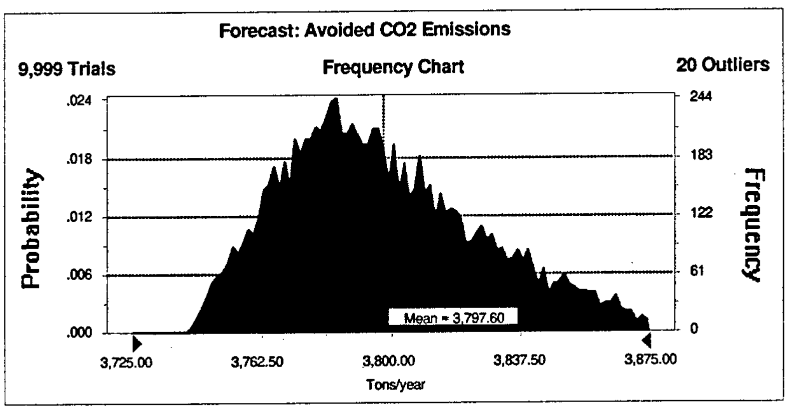
Percentile	Tons/ year
0%	68.50
10%	68.50
20%	68.50
30%	68.50
40%	68.50
50%	68.50
60%	68.50
70%	68.50
80%	68.50
90%	68.50
100%	68.50

End of Forecast

Forecast: Avoided CO2 Emissions Cell: K94

Summary:
Display Range is from 3,725.00 to 3,875.00 Tons/ year
Entire Range is from 3,741.92 to 3,880.75 Tons/ year
After 9,999 Trials, the Std. Error of the Mean is 0.29

Statistics:	Value
Trials	9999
Mean	3,797.60
Median	3,793.61
Mode	---
Standard Deviation	28.60
Variance	818.15
Skewness	0.51
Kurtosis	2.64
Coeff. of Variability	0.01
Range Minimum	3,741.92
Range Maximum	3,880.75
Range Width	138.83
Mean Std. Error	0.29



Forecast: Avoided CO2 Emissions (cont'd) Cell: K94

Percentiles:

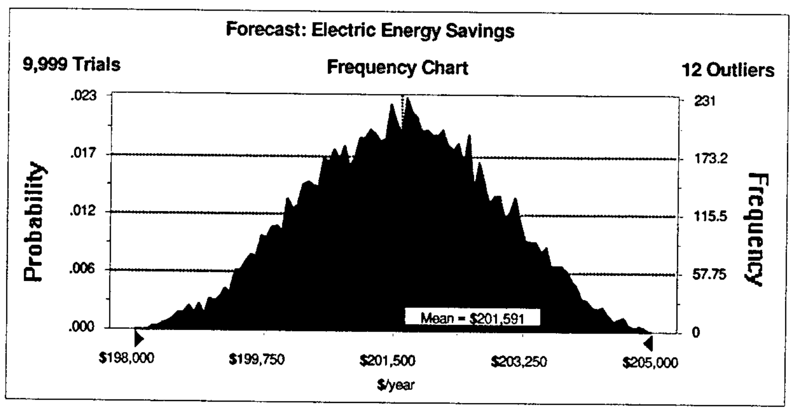
Percentile	Tons/ year
0%	3,741.92
10%	3,763.21
20%	3,772.29
30%	3,779.77
40%	3,786.26
50%	3,793.61
60%	3,801.20
70%	3,810.78
80%	3,822.65
90%	3,839.24
100%	3,880.75

End of Forecast

Forecast: Electric Energy Savings Cell: I79

Summary:
Display Range is from $198,000 to $205,000 $/year
Entire Range is from $197,910 to $205,297 $/year
After 9,999 Trials, the Std. Error of the Mean is $13

Statistics:	Value
Trials	9999
Mean	$201,591
Median	$201,605
Mode	---
Standard Deviation	$1,263
Variance	$1,595,334
Skewness	-0.01
Kurtosis	2.55
Coeff. of Variability	0.01
Range Minimum	$197,910
Range Maximum	$205,297
Range Width	$7,387
Mean Std. Error	$12.63



Forecast: Electric Energy Savings (cont'd) Cell: I79

Percentiles:

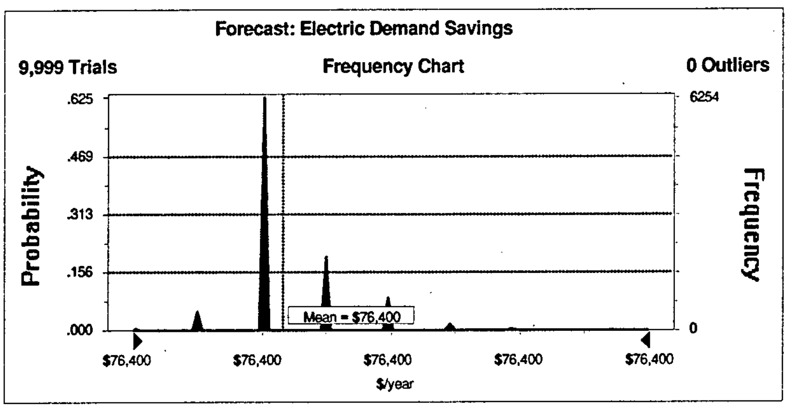
Percentile	$/year
0%	$197,910
10%	$199,919
20%	$200,469
30%	$200,882
40%	$201,257
50%	$201,605
60%	$201,933
70%	$202,291
80%	$202,701
90%	$203,257
100%	$205,297

End of Forecast

Forecast: Electric Demand Savings Cell: J79

Summary:
Display Range is from $76,400 to $76,400 $/year
Entire Range is from $76,400 to $76,400 $/year
After 9,999 Trials, the Std. Error of the Mean is $0

Statistics:	Value
Trials	9999
Mean	$76,400
Median	$76,400
Mode	$76,400
Standard Deviation	$0
Variance	$0
Skewness	0.00
Kurtosis	+Infinity
Coeff. of Variability	0.00
Range Minimum	$76,400
Range Maximum	$76,400
Range Width	$0
Mean Std. Error	$0.00



Forecast: Electric Demand Savings (cont'd) Cell: J79

Percentiles:

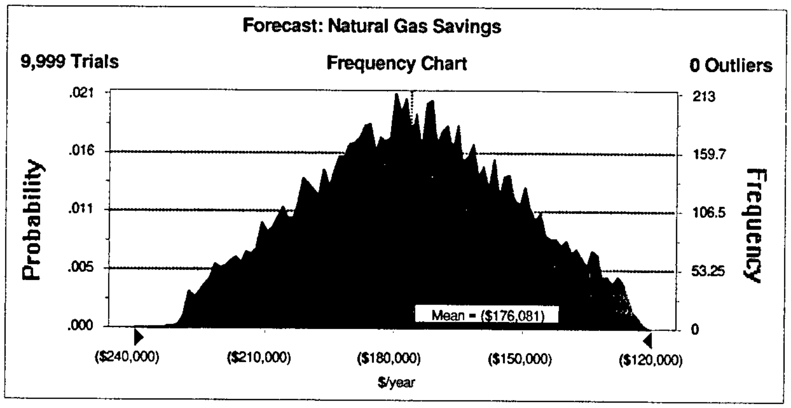
Percentile	$/year
0%	$76,400
10%	$76,400
20%	$76,400
30%	$76,400
40%	$76,400
50%	$76,400
60%	$76,400
70%	$76,400
80%	$76,400
90%	$76,400
100%	$76,400

End of Forecast

Forecast: Natural Gas Savings Cell: K79

Summary:
Display Range is from ($240,000) to ($120,000) $/year
Entire Range is from ($232,028) to ($122,089) $/year
After 9,999 Trials, the Std. Error of the Mean is $237

Statistics:	Value
Trials	9999
Mean	($176,081)
Median	($176,287)
Mode	---
Standard Deviation	$23,682
Variance	$560,848,269
Skewness	0.01
Kurtosis	2.34
Coeff. of Variability	-0.13
Range Minimum	($232,028)
Range Maximum	($122,089)
Range Width	$109,940
Mean Std. Error	$236.83



Forecast: Natural Gas Savings (cont'd) Cell: K79

Percentiles:

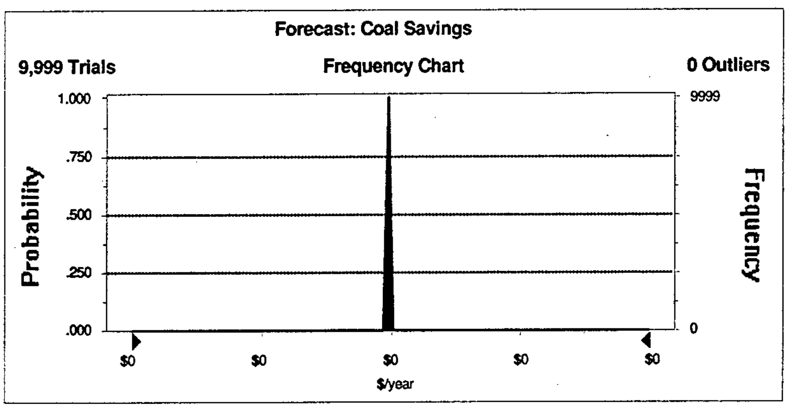
Percentile	$/year
0%	($232,028)
10%	($208,113)
20%	($197,513)
30%	($189,435)
40%	($182,541)
50%	($176,287)
60%	($169,804)
70%	($162,866)
80%	($154,496)
90%	($143,913)
100%	($122,089)

End of Forecast

Forecast: Coal Savings Cell: L79

Summary:
Display Range is from $0 to $0 $/year
Entire Range is from $0 to $0 $/year
After 9,999 Trials, the Std. Error of the Mean is $0

Statistics:	Value
Trials	9999
Mean	$0
Median	$0
Mode	$0
Standard Deviation	$0
Variance	$0
Skewness	0.00
Kurtosis	+Infinity
Coeff. of Variability	+Infinity
Range Minimum	$0
Range Maximum	$0
Range Width	$0
Mean Std. Error	$0.00



Forecast: Coal Savings (cont'd) Cell: L79

Percentiles:

Percentile	$/year
0%	$0
10%	$0
20%	$0
30%	$0
40%	$0
50%	$0
60%	$0
70%	$0
80%	$0
90%	$0
100%	$0

End of Forecast

These assumptions are unique to the model with GSHP. To see other assumptions please refer to the model that assumes Central Heat Plant operation.

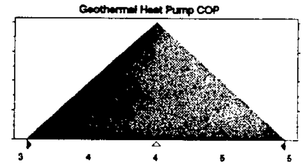
Assumption: Geothermal Heat Pump COP

[RIA MCFC Model w gshp.xls]RIA MCFC Energy Model - Cell: C12

Triangular distribution with parameters:

Minimum	3
Likeliest	4
Maximum	5

Selected range is from 3 to 5
Mean value in simulation was 4



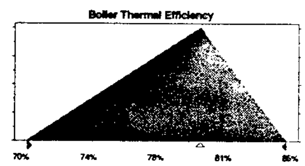
Assumption: Boiler Thermal Efficiency

[RIA MCFC Model w gshp.xls]RIA MCFC Energy Model - Cell: C15

Triangular distribution with parameters:

Minimum	70%
Likeliest	80%
Maximum	85%

Selected range is from 70% to 85%
Mean value in simulation was 78%



Appendix H: Spreadsheet Summary Page Example

MCFC Operating Characteristics:

Unit Capacity =	1,000 kW
Full Load Heat Rate =	7,216 Btu/kWh
Thermal Output =	1.2 MMBtu/hr
Maintenance Downtime =	8%
Estimated Forced Outage Rate =	2%
Total Availability =	90%

GSHP Operating Characteristics:

COP = 4

Boiler Operating Characteristics:

Thermal Efficiency = 74%

Season	Days in Month	Month	Avg Amb Temp (F)	RIA Electric Load Energy MWh	Space Heating Load MMBtu	Heat Pump Elect Load MWh	Hydro Generated Avg Hydro Head (ft)	Hydro Generated Energy Supplied MWh	MCFC Generated Energy Supplied MWh
W	31	Jan	23	9,180	48,103	3,246	11	1,254	670
W	28	Feb	28	9,311	42,936	2,898	12	1,254	605
W	31	Mar	37	9,578	32,379	2,185	10	1,624	670
W	30	Apr	53	10,043	14,019	946	8	1,261	648
W	31	May	66	10,448	0	0	10	1,498	670
S	30	Jun	75	10,709	0	0	9	1,466	648
S	31	Jul	78	10,775	0	0	9	1,358	670
S	31	Aug	72	10,616	0	0	9	1,377	670
S	30	Sep	64	10,382	636	43	11	1,665	648
W	31	Oct	45	9,833	22,338	1,508	11	1,722	670
W	30	Nov	37	9,596	31,672	2,138	11	1,661	648
W	31	Dec	26	9,271	44,509	3,004	11	1,254	670
		Total		119,742	236,592	15,967	121	17,395	7,884

Electric

Season	Days in Month	Month	Avg Amb Temp (F)	RIA Electric Load Peak Demand kW	Heat Pump Elect Load Peak Demand kW	Hydro Generated Peak Capacity kW	MCFC Generated Peak Capacity kW	Purchased w/MCFC Peak Demand kW	Cost w/o MCFC $
W	31	Jan	23	19,059	6,545	1,775	1,000	22,830	$118,672
W	28	Feb	28	19,262	6,468	1,775	1,000	22,955	$119,296
W	31	Mar	37	19,675	4,406	2,285	1,000	20,796	$108,542
W	30	Apr	53	20,394	1,971	1,785	1,000	19,581	$102,492
W	31	May	66	21,020	0	2,112	1,000	17,908	$94,161
S	30	Jun	75	21,425	0	2,067	1,000	18,357	$176,926
S	31	Jul	78	21,525	0	1,918	1,000	18,608	$179,215
S	31	Aug	72	21,280	0	1,945	1,000	18,336	$176,728
S	30	Sep	64	20,919	89	2,342	1,000	17,666	$170,609
W	31	Oct	45	20,069	3,039	2,420	1,000	19,688	$103,024
W	30	Nov	37	19,703	4,453	2,336	1,000	20,820	$108,663
W	31	Dec	26	19,200	6,056	1,775	1,000	22,482	$116,938
		Total		21,525	6,545	2,420	1,000	22,955	$1,575,267

Thermal

Season	Days in Month	Month	Avg Amb Temp (F)	Non-MCFC N.G. Load MMBtu	Process Thermal Load MMBtu	MCFC Thermal Output MMBtu	Process Thermal Natural Gas MMBtu	MCFC N.G. Load MMBtu	Total Load MMBtu
W	31	Jan	23	6,927	24,226	804	31,554	4,832	43,313
W	28	Feb	28	6,430	24,226	726	31,658	4,364	42,452
W	31	Mar	37	5,413	24,226	804	31,554	4,832	41,799
W	30	Apr	53	3,645	24,226	778	31,589	4,676	39,910
W	31	May	66	2,108	24,226	804	31,554	4,832	38,493
S	30	Jun	75	1,113	24,226	778	31,589	4,676	37,377
S	31	Jul	78	865	24,226	804	31,554	4,832	37,250
S	31	Aug	72	1,468	24,226	804	31,554	4,832	37,853
S	30	Sep	64	2,357	24,226	778	31,589	4,676	38,621
W	31	Oct	45	4,446	24,226	804	31,554	4,832	40,832
W	30	Nov	37	5,345	24,226	778	31,589	4,676	41,610
W	31	Dec	26	6,581	24,226	804	31,554	4,832	42,967
		Total		46,697	290,712	9,461	378,888	56,891	482,476

Figure H1. Rock Island Arsenal energy benefits calculations.

Central Plant

Season	Days in Month	Month	Avg Amb Temp (F)	Central Plant Steam Output	Coal	Cost w/o MCFC	Cost w/ MCFC
				MMBtu	MMBtu	$	$
W	31	Jan	23.1493639	0	0	$0	$0
W	28	Feb	27.6119268	0	0	$0	$0
W	31	Mar	36.730715	0	0	$0	$0
W	30	Apr	52.5881303	0	0	$0	$0
W	31	May	66.3785359	0	0	$0	$0
S	30	Jun	75.3054831	0	0	$0	$0
S	31	Jul	77.5290717	0	0	$0	$0
S	31	Aug	72.1214305	0	0	$0	$0
S	30	Sep	64.1470118	0	0	$0	$0
W	31	Oct	45.4033776	0	0	$0	$0
W	30	Nov	37.3409012	0	0	$0	$0
W	31	Dec	26.2533186	0	0	$0	$0
		Total		0	0	$0	$0

Thermal Savings

Season	Days in Month	Month	Electric Energy Savings	Electric Demand Savings	Natural Gas Savings	Thermal Savings	Total Savings
			$	$	$	$	$
W	31	Jan	$16,954	$4,980	-$17,483	$0	$4,451
W	28	Feb	$15,313	$4,980	-$15,507	$0	$4,786
W	31	Mar	$16,954	$4,980	-$16,672	$0	$5,262
W	30	Apr	$16,407	$4,980	-$15,549	$0	$5,838
W	31	May	$16,954	$4,980	-$15,687	$0	$6,247
S	30	Jun	$16,342	$9,140	-$14,985	$0	$10,497
S	31	Jul	$16,886	$9,140	-$15,438	$0	$10,588
S	31	Aug	$16,886	$9,140	-$15,554	$0	$10,473
S	30	Sep	$16,342	$9,140	-$15,234	$0	$10,247
W	31	Oct	$16,954	$4,980	-$16,312	$0	$5,622
W	30	Nov	$16,407	$4,980	-$16,107	$0	$5,280
W	31	Dec	$16,954	$4,980	-$17,258	$0	$4,676
		Total	[redacted]				

Emissions

Emission Factors

	NO_x	SO_x	CO_2	
Electric Utility	8.7	17.4	1713	lb/MWh
Heating Plant	0.42	1.9	180.2	lb/MMBtu
MCFC	0.0003	0.023	930	lb/MWH
NG Boiler	0.03137255	0.00058824	117.6470588	lb/MMBtu

Avoided Emissions

Emissions Avoided (Tons per Year)

	NOx	SOx	CO2
Electric Utility	34.30	68.59	6,752.65
Heating Plant	0.00	0.00	0.00
MCFC	0.00	-0.09	-3,666.06
NG Boiler	0.20	0.00	749.71
Total	[redacted]		

Figure H1. (Cont'd).

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14. ABSTRACT

In this study, the U.S. Army Construction Engineering Research Laboratory (CERL) evaluated the feasibility of siting a 1 MW molten carbonate fuel cell (MCFC) at the Rock Island Arsenal (RIA), Rock Island, IL. The study was conducted in three phases. Phase I surveyed four potential sites. Phase II gave a more detailed description of fuel cell siting characteristics, interface requirements, and preliminary design details. Phase II also analyzed and defined load management benefits resulting from application of the fuel cell, interactions with installed ground source heat pumps, and electrical and thermal energy conservation opportunities at RIA. Phase III provided a more detailed analysis of fuel cell benefits to RIA using the site specifics developed for the proposed MCFC site near the Central Heating Plant. Modeling conducted in the Phase III study indicates with a high degree of certainty that the proposed MCFC power plant installation at RIA has the potential to generate significant cost savings and environmental benefits. The potential savings is higher if the Central Heating Plant is retired. Fuel cell cost benefits will increase if natural gas prices fall.

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