2008

USA Power LLC, USA Power Partners, L. L. C., and Spring Canyon Energy, LLC v. Pacificorp : Brief of Appellant

Utah Supreme Court

Original Brief Submitted to the Utah Supreme Court; digitized by the Howard W. Hunter Law Library, J. Reuben Clark Law School, Brigham Young University, Provo, Utah; machine-generated OCR, may contain errors.
P. Bruce Badger; Fabian and Clendenin; Thomas R. Karrenberg; Stephen P. Horvat; Anderson and Karrenberg; Attorneys for Appellees.
Peggy A. Tomsic; Eric K. Schnibbe; J. Ryan Connelly; Tomsic and Peck; Attorney for Appellants.

IN THE UTAH SUPREME COURT

USA POWER LLC, USA POWER PARTNERS, L.L.C., and SPRING CANYON ENERGY, LLC, Plaintiffs and Appellants, vs. PACIFICORP, JODY L. WILLIAMS and HOLME, ROBERTS & OWEN, LLP, Defendants and Appellees.	Supreme Court Case No. 20080176-SC

VOLUME IV, CONTINUED ADDENDUM TO BRIEF OF APPELLANTS USA POWER, LLC, USA POWER PARTNERS, L.L.C., AND SPRING CANYON ENERGY, LLC

APPEAL FROM THE THIRD JUDICIAL DISTRICT COURT, SALT LAKE COUNTY, STATE OF UTAH, HONORABLE TYRONE E. MEDLEY

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The following materials continue the Addendum of Appellants' Brief. Descriptions of separately-filed papers are in bold, followed by a description of the materials attached to those papers. Portions of the attachments to the described papers that are not central to Appellants' Brief have been omitted.

Tab 1

FILED
THIRD DISTRICT COURT
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SALT LAKE DEPARTMENT
BY [signature]
DEPUTY CLERK

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IN THE THIRD JUDICIAL DISTRICT COURT OF SALT LAKE COUNTY

STATE OF UTAH

USA POWER, LLC, USA POWER PARTNERS, LLC, and SPRING CANYON ENERGY, LLC, Plaintiff, vs. PACIFICORP, JODY L. WILLIAMS and HOLME, ROBERTS & OWEN, LLP., Defendants.	SUPPLEMENT TO AFFIDAVIT NO 2A. OF PEGGY A. TOMSIC IN OPPOSITION TO PACIFICORP'S AND WILLIAMS/HRO'S MOTIONS RE; SUMMARY JUDGMENT (DEPOSITION EXHIBITS) Civil No. 050903412 Judge Tyrone E. Medley

6232

STATE OF UTAH)
:ss.
COUNTY OF SALT LAKE)

Peggy A. Tomsic, being first duly sworn, states as follows:

1. I am the owner of Tomsic Law Firm and a member in good standing of the Utah State Bar. I am one of the lawyers who represents the plaintiffs in this action.

2. Some deposition exhibits that were cited in the oppositions to the various motions for summary judgment were inadvertently omitted from the record I filed in opposition to the defendants' motions for summary judgment. These documents are attached to this Supplemental Affidavit, and are described in paragraphs 3-13.

3. Attached is a true and accurate copy of Deposition Exhibit 5.

4. Attached is a true and accurate copy of Deposition Exhibit 10, P148.

5. Attached is a true and accurate copy of Deposition Exhibit 11, P192-196, P198-203, P218-221.

6. Attached is a true and accurate copy of Deposition Exhibit 20.

7. Attached is a true and accurate copy of Deposition Exhibit 110, pgs. 4, 110-111.

8. Attached is a true and accurate copy of Deposition Exhibit 121.

9. Attached is a true and accurate copy of Deposition Exhibit 157.

10. Attached is a true and accurate copy of Deposition Exhibit 158.

11. Attached is a true and accurate copy of Deposition Exhibit 356.

12. Attached is a true and accurate copy of Deposition Exhibit 357.

13. Attached is a true and accurate copy of Deposition Exhibit 426.

DATED: July 23, 2007.

Peggy A. Tomsic

SUBSCRIBED and sworn to before me this 23rd day of July, 2007.

Colleen Peterson

Notary Public
Residing at: Salt Lake County

Notary Public
COLLEEN PETERSON
50 South Main, Suite 250
Salt Lake City, Utah 84144
My Commission Expires
September 26, 2008
State of Utah

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CERTIFICATE OF SERVICE

I hereby certify that on the 13 day of July, 2007, a true and correct copy of SUPPLEMENT TO AFFIDAVIT NO. 2A OF PEGGY A. TOMSIC IN OPPOSITION TO PACIFICORP'S AND WILLIAMS/HRO'S MOTIONS RE: SUMMARY JUDGMENT (DEPOSITION EXHIBITS) was hand delivered to the following:

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6235

24

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PACIFIC POWER UTAH POWER

July 22, 2003

Theodore T. Banasiewicz, Principal
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Dear Ted:

As you recall when we returned the materials we had received from you folks a couple of months ago, we could not find Volume 2 of the materials that you had sent us. While checking some other files this morning, I found the document, which had been improperly filed and am now returning it to you. I apologize for any inconvenience this may have caused you.

Sincerely yours,

Rand

J. Rand Thurgood
Managing Director, Resource Development

JRT·kll

Enclosure

PENGAD 800-631-6989
EXHIBIT
20

6283

"Development of Procurement Guidelines for Air-Cooled Condensers"

by

Karl R. Wilber, PE
Kent Zammit, Program Manager, EPRI

Prepared for

Advanced Cooling Strategies/Technologies Conference

June 1-2, 2005
Sacramento, California

Sponsored by
Electric Power Research Institute (EPRI)
California Energy Commission (CEC)

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"Development of Procurement Guidelines for Air-Cooled Condensers"

By
Karl R. Wilber, PE
Kent Zammit, Program Manager, EPRI

1 Abstract

The use of Air-Cooled Condensers (ACCs) for steam electric power plants has been historically been very limited, especially in the United States. However, with increased focus on water conservation, combined with continued concern over the environmental effects of both once-through and evaporative cooling, the application of ACC's to power plants condenser heat rejection is expected to increase. Indeed, particularly in the Southwestern United States, this has already happened.

As a result of limited operating experience with ACC's and proprietary and evolving dry-cooling technologies, there is no single depository of performance and operations and maintenance experience. Recognizing the increased interest in ACC's and the aforementioned limitations in available data, the Electric Power Research has commissioned Project EPP-P10612/C5386 to develop "procurement guidelines" for ACC's.

This paper presents the results of this work in progress and includes the following areas:

A. An assessment of operating and performance issues with ACC's,
B. The development of information that should be included in and solicited via procurement specifications for ACC's,
C. An example procedures for evaluation and comparisons of bids, and
D. Guidelines for Performance and Acceptance Testing of ACC's.

Particular emphasis is placed on observations of the effects of winds on the performance of ACC's. Recommendations for language which might be incorporated into procurement specifications, in this regard, are also included. Finally, a summary of a proposed test guideline for ACC's is included as Codes for these tests are under development by both the American Society of Mechanical Engineers and the Cooling Technology Institute, and are not expected to be published in the foreseeable future.

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2 Introduction

2.1 *EPRI Project Overview*

With increased focus on water conservation, combined with continued concern over the environmental effects of both once-through and evaporative cooling, the application of ACC's to power plants condenser heat rejection is expected to increase. Evidence of this trend is apparent in the Southwestern United States, where population growth and development initiatives solicit increased power generation, while competing for limited supplies of water.

As a result of limited operating experience with ACC's and proprietary and evolving dry-cooling technologies, there is no single depository of performance and operations and maintenance experience. Recognizing the increased interest in ACC's and the aforementioned limitations in available data, the Electric Power Research has commissioned Project EPP-P10612/C5386 to develop "procurement guidelines" for ACC's. This paper summarizes some of the key products of that project.

2.2 *Site Assessments and Potential Areas of Focus*

Numerous specifications, technical papers and books [1,2], have been developed for ACC's both internationally and in the United States. The specifications, for the most part, cover the design conditions, scope of supply, codes and standards, contract terms and conditions, etc. In most cases, these specifications have not addressed areas that might be problematic, in terms of ACC performance, operation and maintenance. In developing information that was felt important to ACC specifications, a number of sites were visited as part of the specification development process. Interviews with both plant personnel and suppliers were conducted, in order to gain a balanced viewpoint on key issues. The following areas surfaced as ones which deserved additional attention, beyond the historical level that they have received:

2.2.1 Wind Effects

Prevailing winds can be significant at many sites, especially given the typical height of air inlets and fans (e.g. 50-100ft (15-30 m)) on an ACC. High winds can cause reduced inlet pressures on upwind fans of an ACC leading to reduced airflow rates and cell thermal performance. Prevailing winds can also lead to recirculation of the heated exhaust air from the ACC, also leading to reduced performance of the ACC. This area, i.e. wind effects (which includes issues such as fan performance impacts, recirculation effects, tube bundle exhaust air flow, and interference), represents a major challenge associated with ACC specification, design and performance.

2.2.2 Range of Operating Conditions

ACC's may be required to operate over ambient temperatures ranging from less than 0°F to over 110 °F. Further, they may also be required to undergo "cold starts" (i.e. initial operation without a heat load) and operate successfully over a full range of heat loads. In doing so, particular attention in the design and operation of the ACC to prevent freezing of condensate as well as proper removal of non-condensables is critical.

2.2.3 Fouling of ACC Coils

Many ACC's operate in areas with high ambient dust loadings. This is particularly true in the desert Southwest portion of the U.S., where a number of ACC's have recently been commissioned. In some situations, beyond ambient dusts, pollen, insects, etc. can foul heat exchange surfaces. Further, leaky gear boxes lead to carryover of gear box grease to the heat exchange surfaces. It may also be the case that nearby fuel piles, including coal, hog fuel (i.e. wood waste) etc. can contribute to the inlet air dust loadings to the ACC and resultant fouling. As a result of site visits, incorporation of potential dust loadings, fin-tube cleaning systems and performance degradation trends warrant additional consideration.

2.2.4 Inlet Air Conditioning

A number of ACC Owner/Operators have experimented with and/or are using methods for inlet air cooling of the ACC. The notion of reducing the inlet air dry-bulb temperature, particularly during periods of elevated temperatures is obviously important when power output requirements are highest. Inlet air cooling typically involves evaporative cooling of the air via either film or spray cooling. In the case of film cooling, additional pressure drop on the inlet air side can be a challenge. In the case of spray cooling, carry over of sprayed droplets can also be problematic. Indeed, spray cooling via atomized sprays, has resulted in degradation of finned tube surfaces at a number of sites. The main reason for this is felt to be improper selection, positioning and/or orientation of atomizing technologies. Accordingly, one should not write off the prospect for inlet air cooling via sprays.

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3 ACC Specification Development

3.1 Development of Design Conditions

The *minimum* amount of information required to establish the simplest design point for an ACC is:

- Steam flow, W (lb/hr)
- Turbine exhaust team quality, x (lb dry steam/lb turbine exhaust flow)
- Turbine backpressure, p_b (in Hga)
- Ambient temperature, T_{amb} (deg F)
- Site elevation, (ft---above sea level)

"Steam flow" refers to the total flow passing through the steam turbine exhaust flange and consists of both dry steam and entrained liquid water droplets.

"Steam quality" refers to the fraction of the steam flow which is dry steam and is expressed as a decimal fraction or a percent. All dry steam at saturation conditions has a quality of 100% (x = 1.). An equivalent description sometimes used is "steam moisture" (ξ) defined as the percent of liquid water in the "steam flow". Therefore,

$$\xi = 1. - x \qquad \{1\}$$

These quantities are used, along with the thermodynamic properties of steam and water including the latent heat of vaporization, h_{fg} (Btu/lb), at the design condensing pressure, to determine the heat load, Q (Btu/hr), which must be handled by the ACC. Since the heat load is determined by the total steam flow times the difference between the enthalpy of the inlet steam, $h_{steam\ inlet}$ (Btu/lb) and the enthalpy of the leaving condensate, h_{cond} (Btu/lb), it can be shown that

$$\mathbf{Q(Btu/hr) = W(lb/hr) * x(lb/lb) * h_{fg}(Btu/lb)} \qquad \{2\}$$

The turbine steam flow and quality at the plant design load are obtained from information provided by the turbine vendor.

In addition to these basic quantities, the ACC design (and cost) may be affected by a number of plant and site characteristics which are listed below.

- Site characteristics
  - Meteorology
    - Annual temperature duration curves
    - Prevailing wind speeds and directions
    - Extreme conditions (hottest day; freezing conditions)
- Topography and obstructions
  - Nearby hills, valleys, etc.
  - Nearby structures, coal piles, etc.

- Nearby heat sources---aux. coolers, plant vents, etc.
- Other
  - Noise limitations
    - At ACC
    - At some specified distance---neighbors, sanctuaries, etc.
  - Maximum height restrictions
  - "Footprint" constraints (length, width)
  - Location restrictions---distance from turbine exhaust

3.2 Basic Design Determination

Specification of the quantities and characteristics above are sufficient to obtain a "budget" estimate from ACC vendors. The following example illustrates the considerations in selecting an appropriate design point.

An ACC for installation at a 500 MW (nominal), gas-fired combined-cycle plant located in an arid, desert region might select the following design values:

• Steam flow, W (lb/hr):	1.1×10^6
• Quality, x (lb/lb)	0.95
• Backpressure, p_b (in Hga)	4.0
• Ambient temperature, T_{amb} (F)	80
• Site elevation	Sea level (p_{amb} = 29.92 in Hga)

The values were selected as follows:

Steam flow:

As derived from Figure 1, the design steam flow for a number of modern plants plotted against steam turbine output can be reasonably correlated by:

$$W(\text{lb/hr}) = 17{,}459 * (MW_{steam})^{0.8132} \qquad \{3\}$$

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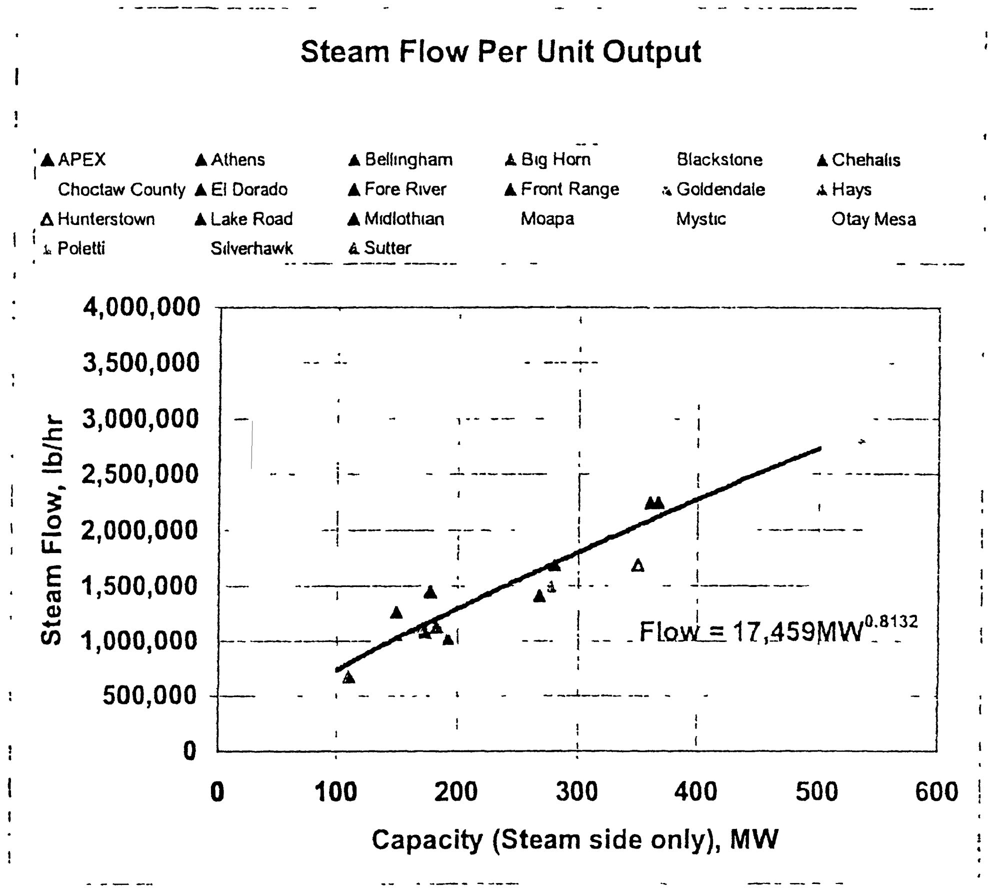

3.2 1.1 Figure 1- Correlation of Steam Flow vs. Turbine Output

For a nominal 500 MW, 2 x 1 combined-cycle plant, the steam-side capacity is approximately one-third of the plant total or about 170 MW with a corresponding steam flow of approximately 1.1 x 10^6 lb/hr.

Steam quality·

Turbine steam exit quality (or enthalpy) must be obtained from the specific turbine design information or be determined from full-scale turbine tests. Typical values range from 0 92 to 0.98 For estimating purposes, a quality of 0 95 (5% moisture) is a reasonable value. Additional insights are provided in the section on performance testing.

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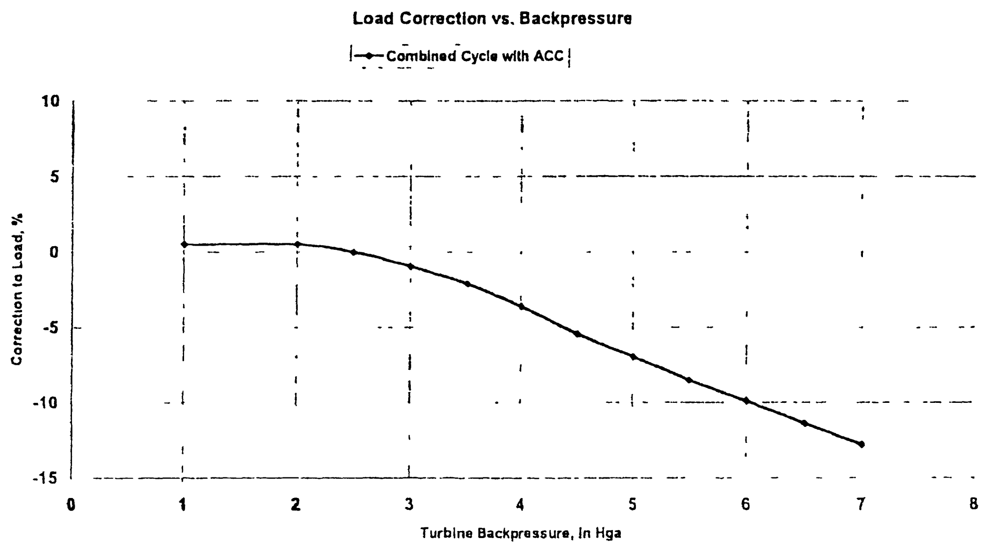
Turbine backpressure and ambient temperature:

For a given heat load, the combination of turbine backpressure and ambient temperature at the design point essentially determines the size, fan power, cost and off-design performance of the ACC.

Backpressure—Over the normal operating range, the turbine efficiency improves (heat rate decreases) as the backpressure is lowered Figure 2 displays a typical Load Correction vs. Backpressure curve for a turbine selected for use on a combined-cycle plant with an ACC. Below about 2.0 to 2.5 in Hga, no further reduction in heat rate is achieved and, in some instances, a slight increase occurs. Most turbines are restricted to operating at backpressures below 8. in Hga (typical guidelines are: "alarm" @ 7. in Hga; "trip" @ 8. in Hga).

Ambient temperature---At the desert site chosen for this example, the ambient temperature varies widely during the year. Figure 3 shows a temperature duration curve based on 30-year average data from El Paso, Texas. Other Southwestern sites are comparable.



3 2 1 2 Figure 2 - Steam Turbine Performance vs Backpressure

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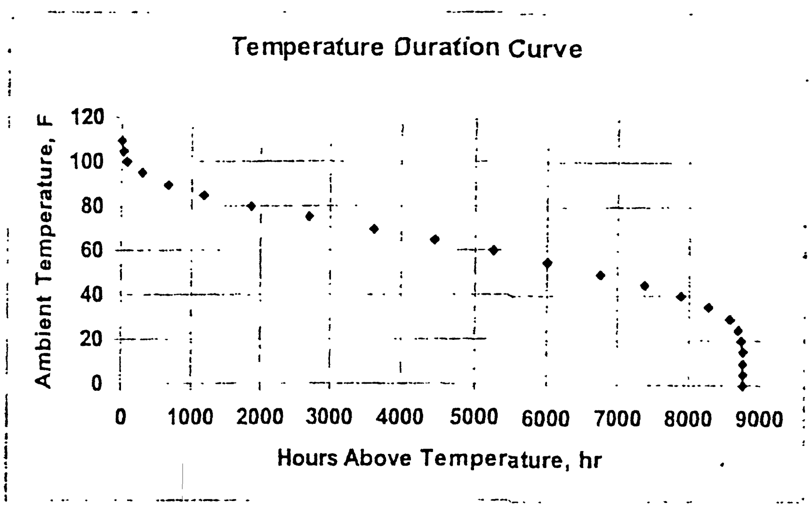

3.2.1.3 Figure 3 - Example Temperature Duration Curve

Typical ambient temperature points selected for the design ambient temperature might include the annual average temperature, the summer (June through September) average temperature and the 1% ambient dry bulb (the temperature exceeded only 1% of the year). For this site, these temperatures are:

- Annual average: 65 F
- Summer average: 80 F
- 1% Dry bulb: 99 F

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Table 1 lists the Initial Temperature Differences (ITD) for a few combinations of ambient temperatures and condensing pressures

3 2 1 4 Table 1- ITD Examples for Varying Ambient Temperatures

Initial Temperature Difference (ITD), F				
Condensing Pressure	Condensing Temperature	Ambient Temperature, F		
		65	80	99
in Hga	F	F	F	F
2.5	108.5	43.5	28.5	9.5
3.5	121.1	56.1	41.1	22 1
4.0	126.1	61.1	46.1	27.1
6.0	140.8	75.8	60.8	41.8
8.0	151.8	86 8	71.8	52.8

As can be seen from Table 1, the pairing of a high ambient design temperature with a low design condensing pressure results in a low ITD and, correspondingly, a large and expensive ACC, which would be oversized for most of the year. Conversely, a low design ambient temperature paired with a high design condensing pressure yields a high ITD, a small, inexpensive ACC, but one that would perform poorly during much of the year and severely limit plant output during the hotter periods.

3.2.2 Industry Trends

Over the past twenty years the chosen ITD's for ACC's have gradually decreased and are now typically in the mid-40°F's or lower. This suggests that the balance of market forces and operating experience over that time have led to the selection of larger units, (having higher capital cost) in order to reduce the performance penalties throughout the year, and particularly during the hotter prevailing ambient conditions. Units with ITD's as low as 50 F were chosen in the early 1980's and as high as 62 F in the late 1990's Plants whose business strategy and returns depend on selling high priced power during the hottest peak load periods, may well opt for a large unit with a design ITD well below the typical "mid-40's" Further, specification of lower ITD's may reflect greater sensitivity to wind effects on performance and the fact that this is at least one avenue to compensate for these impacts

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4 General Verification of Performance Requirements

General verification of performance of an ACC can generally be conducted by solicitation and evaluation of some of the following information.

4.1 General Requirements Overview

4.1.1 Initial Temperature Difference (ITD)

The ITD will typically be in the range of 25°F (14°C) to 60°F (33.3°). Note that ITD's approaching the low end of this range will result in equipment sizing that may be uneconomical for a specific plant, notwithstanding the obvious benefits to the turbine efficiency. On the other hand, high ITD's, especially in the event of wind-induced performance deficiencies may well result in derating of the power generation unit or a steam turbine trip.

4.1.2 Steam Quality

Steam quality is the weight fraction of steam or percentage of steam at the turbine exhaust. It is typical to have some moisture in the exhaust steam. Typical values of steam quality are 90-95percent, but may be lower depending upon operating conditions of the system. If steam quality were to exceed 100 percent, it would suggest superheated steam still exists at the turbine exhaust. As air-cooled condensers are designed to condense steam and not cool superheated steam, steam quality values at or above 100 percent are not appropriate.

4.1.3 Steam Turbine Exhaust Pressure

Steam turbine exhaust pressure, commonly referred to as "back pressure", will typically be in the range of 2.5 to 7.5 inch Hga. Pressures above this level will typically exceed steam turbine manufacturers' warranties. Accordingly, this high level may be set as a "trip point" (i.e. automatic shut down) for the unit.

4.1.4 Verification of Supplier Performance Requirements of the Air-Cooled Condenser

This section focuses on the Single Row Condenser (SRC) design as it is the most widely offered in response to current air-cooled condenser bid solicitations.

Number of Cells- The number of cells (also referred to as modules) is clearly an important part of the supplier data. Obviously, the number of cells dictates the amount of mechanical equipment (i.e. fans, motors, gear boxes). Further, many current large-scale SRC designs use components, whose dimensions are optimized for shipping and erection. For instance, use of 33 ft (10 meter) diameter fans and individual tube bundle sections of approximately 36 ft (~11m) and with 8 ft (~2.5m)/bundle and 5 bundles per cell per side for a plan area of 36ft by 40ft per cell per side. As a result, the number of cells often dictates a number of features of the air-cooled condenser, including the mechanical equipment as well as the amount of heat transfer surface.

The total number of cells or modules is the sum of the Primary and Secondary Modules. The Primary Modules are responsible for the majority of the heat transfer and condensing, while the Secondary Cells are responsible for residual heat transfer and condensables collection and evacuation.

Number of Primary Modules – The number of Primary Modules is typically about 80 percent of the total number of modules.

Length of Primary Modules - The length of the primary modules is typically on the order of 33ft-40ft (10-13 m) for a Single Row Condenser type system.

Number Of Secondary Modules – The number of Secondary Modules is typically about 20 percent of the total number of modules and there is typically one module per row (or street).

Length of the Secondary Modules – these modules are typically shorter than the primaries by about 3-5 ft (~1 – 1.5 m).

Primary Module Dimensions – (Width) – Obviously the width of the primary modules must be greater than the fan diameter and typically run on the order of 15-25 percent larger than the fan diameter.

Fan Characteristics – Fan diameters for ACC's used on most recent power plant applications are typically 30-37 ft (10-12m). The number of blades per fan will minimally be 5 but may be as many as 8-10 depending upon the fan supplier and the performance requirements.

Motor Characteristics – Fan motor power must be equal to that required by the fan shaft power divided by the motor and gear box efficiencies. Often a margin of 5-10 percent if provided, in addition to service factor margins.

4.1.5 Additional Vendor-Supplied Data

A bid specification should also solicit the following information.

Overall Heat Transfer coefficient, U, (based on air-side surface area)

b. Total Air-Side Surface Area, **A**
c. Total Mass Flow Rate of Air at Each Design Condition, **$m`_{air}$**
d. Fan Static Pressure (**p_{static}**) or the total system pressure drop.
e. Log Mean Temperature Difference (LMTD)
f. Steam Duct Pressure Drop
g. Heat Exchanger Bundle Pressure Drop (Steam Side)

4.1.6 Important Items for Verification

Thermal Duty – It is important to verify that the thermal duty solicited (i.e. the amount of heat to be rejected) is matched or exceeded by the supplier's offering.

$$Q_{required} = m`_{steam} \times (h_{steam, (turbine\ exhaust)} - h_{(condensate)})$$
$$Q_{rejected} = U \times A \times LMTD$$

Heat transfer Area – This is calculated knowing the total heat transfer area of the tubes in the ACC's. For a Single Row Condenser (SRC), the ratio of the air-side surface area and the total "face" area is approximately 124.

Outlet Air Temperature – The outlet air temperature is obviously less than the steam temperature and can be calculated from the following equation:

$$Q_{required} = m` \times C_{p\ air} \times (T_{air,out} - T_{air,in})$$

Face Velocity of the Air - The face velocity of the air, while not typically provided by the supplier, can be calculated from the mass of air flow rate, the air density, and the total face area of the ACC. Typical values will run from about 3 ft/sec (~1m/s) to as much as 8-10 ft/sec (~3 m/s) with the average being about midway between those limits. (Those who have performed velocity measurements at the exit plane of an ACC know that, while the average velocity may be in those limits, variations of a factor of 5 can occur at the outlet).

Fan Static Pressure - Fan Static Pressures will vary depending upon whether the fan is a low-noise or more standard design. Fan Static Pressure, which in essence is the force required to overcome the system resistance (with the required design air flow rate), will run on the order of 0.3 – 0.5 inches of water (~100 Pa +/- 20%) for a standard fan and system design.

Fan Shaft Power or Brake Horsepower - Depending upon the fan static efficiency, one can calculate whether the fan system will deliver the appropriate amount of air.

Power Requirements - Total fan power can be calculated using the aforementioned information and assuming nominal gear box efficiencies of ~97% and motor efficiencies ~92-94%.

5 ACC Performance Test Code Development

Having reviewed some of the key items to solicit in a Specification, as well as those items to check in the bid evaluation stage, the "rubber truly meets the road" with a thermal acceptance test of the equipment.

The American Society of Mechanical Engineers (ASME) and the Cooling Technology Institute (CTI) are currently developing Performance Test Codes for Air Cooled Condensers (ACC). In some respects, development of these Codes may solicit additional caveats for its users.

When test codes are employed for both specification and performance testing of equipment, those who reference them have an inherent confidence that the equipment designed, delivered and successfully tested in accordance with the Code should adequately perform in a plant environment. This is typically the case for components such as turbines, pumps, condensers, and even, for the most part, evaporative cooling towers. Having said that, it is recognized that the performance of evaporative cooling towers can deteriorate under certain wind conditions. Indeed, the impacts of and responsibility for plume recirculation on evaporative cooling towers were key issues for the rewriting of ASME's PTC 23 Atmospheric Water Cooling Equipment. [3,4]. For the ACC Code Committees at ASME and CTI, it would appear that the challenges are greater yet. The key issues are:

- *ACCs, which perform adequately under the limits of Test Code conditions, may not perform adequately, at all, under normal and prevailing site conditions.*
- *The available knowledge base on wind and performance effects is comparatively limited as the population of and operating experience on larger power plant ACC's, at least in the United States, is limited,*
- *The purchase of ACC's, like most other plant equipment, is cost driven and there are typically no incentives for equipment suppliers to build margin into the design and performance of their offerings.*

5.1 Examples of Performance Impacts

Recognized impacts on ACC performance include:

5.1.1 Wind Effects

Prevailing ambient winds can be high (>10-20 mph) at some sites, leading to:

a. **flow separation** at the fan inlet and poor fan performance,
b. **recirculation** of the hot exit air into the air inlet of the ACC, and
c. **mal-distribution** of the air in the plenum and across the heat exchange surfaces. (additional detail can be found in Reference [2].)

5.1.2 Local Interferences

The location of the ACC is necessarily closer to heat sources such as service water cooling systems, turbine exhaust piping, etc. than evaporative cooling towers typically are from the Plant. The entrained air from adjacent sources is very likely to be warmer than design or ambient conditions and therefore the performance of the ACC is negatively impacted.

The net affect of these conditions is that an ACC that appears to meet performance guarantees under the limits of a Test Code, may perform poorly under conditions that prevail at the site. Those who specify, design and own/operate ACCs should be aware of this. Example situations follow:

5.1.3 Example 1 - Waste to Energy Plant

The 3 cell ACC at this site serves a small wood waste power plant. Significant recirculation of the exhaust plume, with localized inlet temperatures exceeding 125F, occurred at this site prior to installation of "wings" down both longitudinal sides of the ACC. Further, a wind screen was installed to reduce wind affects and minimize the entrainment of saw dust in the ACC inlet air. The impact on ACC performance, due to recirculation and flow separation was not anticipated and therefore retrofits of the ACC were made. Inlet air spray cooling is also used at this site.

5.1.3.1 Figure 4 - "Wing" Extensions to Reduce Recirculation

5.1.3.2 Figure 5 - Wind Wall Adjacent to ACC

5.1.4 Example 2 - Small Combined-Cycle Plant ACC

As is the case with many sites employing ACCs, this 20Mwe Plant is located in a water short area. The service water cooling system for this site is an adjacent air-cooled heat exchanger, the exhaust from which enters the inlet of the ACC, when the winds are from the northwest. During a site visit to this plant, localized air temperatures from the service water heat exchanger were 90-92F while the prevailing ambient temperatures ranged from 63-67F. The impact of this on the performance of the ACC was not taken into account during the initial system design and inlet air spray cooling is being considered for peak temperature and load conditions.

5.1.5 Example 3 - Combined-Cycle Power Plant

This plant, located in the desert southwest, has prevailing winds that often exceed 15-20 mph. Impacts of plume recirculation and flow separation have been significant, leading, at times, to de-rating of the plant by nearly 10 percent of its capacity. Retrofits on the ACC included wind walls around the ACC finned tubes to reduce recirculation and perpendicular wind screens below the ACC to reduce wind effects on fan and ACC performance. While the equipment may have met its original performance guarantees, the impacts of prevailing winds have resulted in performance shortfalls that were unanticipated in the original specifications and design process.

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5.1.6 Example 4 - ESKOM's Matimba Power Station – South Africa

The Matimba Plant consists of six 680MWe coal-fired power plants. The turbine exhaust is condensed via air-cooled condensers, an aerial view of which is shown in the figure below (courtesy of J. Cuchens, Southern Company).

5.1.6.1 Figure 6 - ESKOM's 680Mwe Matimba Power Station

The ACCs at Matimba are positioned adjacent to the turbine hall on the north side of the Plant. Even though efforts have been made to modify the area, the inlet air path between the turbine hall and ACC's is substantially restricted as a result of the Plant buildings. Prevailing winds are from the Northeast.

Goldshagg [5] reported that turbine performance at the Plant was measurably reduced during certain windy periods and that turbine trips had occurred during gusty conditions. This is not to suggest that turbine back pressures often exceed manufacturer's or plant limits, however, the rate of change of back pressure was significant enough, on more than one occasion, to trigger a Unit trip. The plant has now installed a computer screen, which displays instantaneous wind speed and direction and provides operator guidance on conditions which may impact unit operation. Further, the site has initiated a number of evaluations of inlet air cooling via use of localized spray nozzles.

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Those who develop specifications as well as Test Code committee members should consider additional guidance, to those that use the code, calling to their attention the fact that ***actual operating performance of ACC's may be substantially lower than that determined by a test conducted under the limitations currently contemplated by the Code.***

5.2 Testing Guidelines

This section excerpts *(in italics)* portions of the test procedures that are planned for incorporation into the EPRI ACC Specification.

5.2.1 Scope

"1.1 Scope
This document details the measured test parameters, instrumentation, test measurements and data reduction procedure required for determination of the thermal capability of a dry, air-cooled steam condenser (ACC). The procedure focuses on contractual acceptance testing of a new unit, but the same procedure may be used for performance testing of an existing unit.

1.2 Basis
As of this writing there is no American test code for air-cooled condensers. Both the Cooling Technology Institute (CTI) and the ASME are currently working on performance test codes for this major plant component. In the absence of a controlling test code, several resources have been used in the preparation of this guideline. These are:

- ***VGB Guideline for Acceptance Test Measurements and Operation Monitoring for Air Cooled Condensers (1997)***
- ***Code of Practice for Acceptance and Operating Tests of Air Cooled Steam Condensers (published by the Association of German Electricity Supply Authorities in 1965)***
- ***ASME PTC 12.2 Steam Surface Condensers***
- ***CTI ATC-105 Acceptance Test Code for Water Cooling Towers (2000)***
- ***ASME PCT-23 Atmospheric Water Cooling Equipment (2003)***

1.3 Test Plan
A test plan is a convenient vehicle for specification of responsible test participants required preparations, measurement locations, test instrumentation, acceptable test conditions, anticipated deviations to the governing test code, required adjustments to plant operations, calculation procedures, and expected test uncertainty. As an example, the measurement of steam flow and the estimation of steam quality will require the use of plant instruments, particularly flow elements. It is vital that such instruments be identified prior to the test so that any necessary calibrations can be performed. In addition, measurement of condensing pressure requires the installation of basket tips

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which may be different in number and location than those used by the plant for monitoring purposes. The preparation of a test plan, approved by manufacturer and the ACC purchaser prior to the test, is highly recommended." ....

Again – as excerpted from the EPRI ACC Draft Specification.........

5.2.2 Conditions of Test

"2.1 Test Witnesses

For acceptance testing, representatives of the owner and condenser manufacturer shall be given adequate notice prior to the test. The manufacturer shall be given permission, opportunity and adequate notice to inspect the ACC and prepare the ACC for the test. In no case shall any directly involved party be barred from the test site.

2.2 Conditions of the Equipment

At the time of the test, the ACC shall be in good operating condition. Steam duct and condensate piping systems shall be essentially clear and free of foreign materials that may impede the normal flow of steam and condensate.

Mechanical equipment, including fans, gear, motors, pumps, air ejectors, etc., shall be clean and in good working order. Fans shall be rotating in the correct direction, with proper orientation of the leading and trailing edges. Fan blade pitch shall be set to a uniform angle that will yield within ±10% of the specified fan driver input power load as measured at the motor switchgear.

Air in-leakage must be such that the vacuum equipment has 50% excess holding capacity during the test.

ACC air inlet perimeter area and discharge area shall be essentially clear and free from temporary obstructions that may impede normal airflow.

The air side of the ACC fin tube bundles shall be essentially free of foreign material, such as pollen, dust, oil, scale, paper, animal droppings, etc.

Water level in the condensate hotwell tank shall be at the normal operating level.

Representatives of the ACC purchaser and manufacturer shall agree prior to commencement of testing that the cleanliness and condition of the equipment is within the tolerance specified by the manufacturer. Prior establishment of cleanliness and condition criteria is recommended.

h) All emergency drain lines which have the potential for delivering superheated steam to the condenser shall be isolated. A closed valve shall be considered adequate isolation.

5.2.3 Operating Conditions

The test shall be conducted while operating as close to the operation/guarantee point(s) as possible In any event, the test shall be conducted within the following limitations

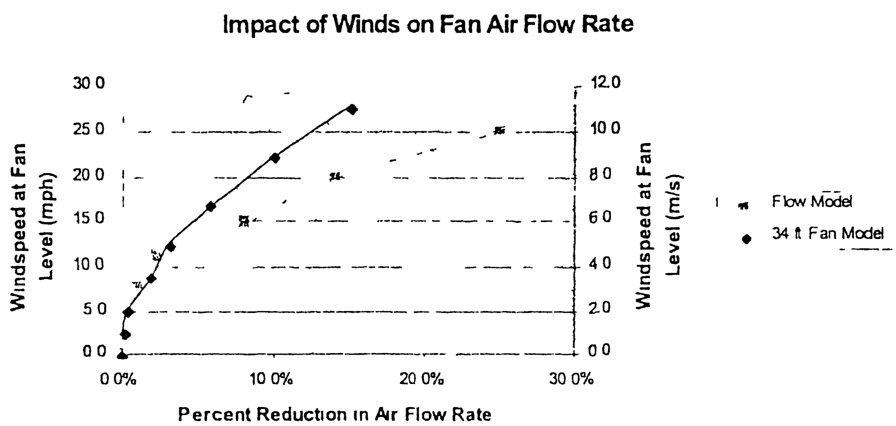
2 3 1 The test dry-bulb temperature shall be the inlet value, measured in accordance with paragraph 3 3 of this test procedure.. .... "

{Note The following wind limitations are similar to what is being considered by ASME and CTI – however, the performance of the ACC under higher wind conditions will undoubtedly suffer }

2 3 2 The wind velocity shall be measured in accordance with Paragraph 3 7 of this test procedure and shall not exceed the following·

Average wind velocity shall be less than or equal to 5 m/s (11 miles per hour)
One minute duration velocity shall be less than 7 m/s (15.6 miles per hour).

Owner/Operators should realize that Air-Cooled Condensers whose performance appears satisfactory under low-wind conditions will fall short of expectations under higher wind conditions. (See Figure 7, below).



5 2 3 1 Figure 7 – Potential Impact of Winds on Fan Performance

It is noted here that Kroger [1] suggests the prospect for even greater wind penalties in his example on heat exchanger fan performance

2 3 3 The following variations from design conditions shall not be exceeded
<u>Dry-bulb temperature</u> - ±10°C from design (18°F) but greater than 5°C (41°F)

Condensate Mass Flow - *±10% of the design value.*
Fan Motor Input Power - *±10% of the design value after air density correction. (Eq. 4-7)*

2.3.4 Steam turbine exhaust steam shall be distributed to all modules as recommended by the manufacturer. For the purposes of this Code, a "module" is defined as the smallest subdivision of the ACC, bounded externally by fin tube bundles and internally by partition walls, which can function as an independent unit. Each module generally has a single fan.

2.3.5 There shall be no rain during the test period nor in the one hour period preceding the test period.

2.3.6 Steady state operation of the ACC shall be achieved at least one hour before and maintained during the test.

5.2.4 Constancy of Test Conditions

For a valid test, variations in test conditions shall be within the following limits.

2.4.1 The variation in test parameter shall be computed as the slope of a least squares fit of the time plot of parameter readings. Condensate mass flow shall not vary by more than 2 percent during the tests.

2.4.2 The inlet dry-bulb temperature shall not vary by more than 3°C (6°F).

5.2.5 Duration of the Test

After reaching steady state conditions, the requirements for the test duration shall be at least one hour. Longer test intervals are acceptable provided the constancy of test conditions is observed.

5.2.6 Frequency of Readings

Readings shall be taken at regular intervals and recorded in the units and to the number of significant digits shown in Table 2.0.

Table 3. Measurement Frequency			
Measurement	*Minimum Readings per hour per station*	*Unit*	*Recorded to Nearest*
ACC Condensate Mass Flow [1]	*60*	*kg/h (lb/h)*	*0.1 %*
Condensate Hotwell Tank Level	*60*	*m (ft)*	*0.01 (0.03)*
Exhaust Steam Pressure	*60*	*kPa (in.HgA)*	*0.005 (0.01)*
Exhaust Steam Temperature (for comparison)	*60*	*°C (°F)*	*0.05 (0.1)*
Inlet Air Dry-bulb Temperature	*60*	*°C (°F)*	*0.01 (0.01)*
Atmospheric Pressure	*1*	*kPa (in. Hg)*	*0.2 (0.05)*
Ambient Wind Velocity	*60*	*m/s (mph)*	*0.1 (0.2)*
Fan Power at Switchgear	*1*	*kW (hp)*	*0.5%*

The test procedure in the EPRI ACC Specification document contains data acquisition and analyses procedures as well as options in the Appendices for determination of steam quality. One such option follows, where an attendant steam turbine test is being conducted – as would often be the case when conducted an acceptance test on a new plant.

From Appendices of Test Section......

5.2.7 Procedure for Calculation of Steam Quality at Turbine Exhaust

(again, excerpted from the draft EPRI ACC Specification)

The procedure that follows assumes that the slope of the enthalpy versus entropy line for the low pressure steam turbine is independent of the exhaust pressure, inlet temperature, pressure and flow. This is equivalent to assuming a constant isentropic efficiency for the low pressure turbine. Studies using cycle models have indicated that the error involved with calculating the steam quality based on this assumption is less than 1 percent.

1. *From the turbine heat balance diagram corresponding to the air cooled condenser design conditions, obtain the inlet temperature and pressure for the low pressure turbine as well as the turbine exhaust enthalpy and pressure.*
2. *Using steam tables or equivalent software look up (or calculate) the specific enthalpy and specific entropy of the low pressure turbine inlet steam.*
3. *Calculate the quality of the turbine exhaust steam by:*

$$X_d = \frac{h_{e\,d} - h_{l,d}}{h_{v\,d} - h_{l,d}}$$

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where

X_d	=	*the moisture fraction of the turbine exhaust at the heat balance conditions*
$h_{v,d}$	=	*the specific enthalpy of saturated vapor at the exhaust pressure*
$h_{e,d}$	=	*the specific enthalpy of the exhaust steam*
$h_{l,d}$	=	*the specific enthalpy of saturated liquid at the exhaust pressure*

This value should correspond to the guarantee condition for the condenser.

4. *Calculate the entropy of the turbine exhaust steam by:*

$$s_{e,d} = (1 - X_d)s_{v,d} + X_d s_{l,d}$$

where

s_e	=	*the specific entropy of turbine exhaust steam*
$s_{v,d}$	=	*the specific entropy of saturated vapor at the turbine exhaust pressure*
$s_{l,d}$	=	*the specific entropy of saturated liquid at the turbine exhaust pressure*

5. *Calculate the slope of the "expansion line" by:*

$$m_e = \frac{h_{i,d} - h_{e,d}}{s_{i,d} - s_{e,d}}$$

where

m_e	=	*slope of the expansion line*
$h_{i,d}$	=	*enthalpy of the low pressure turbine inlet steam*
$s_{i,d}$	=	*entropy of the low pressure inlet steam*

Note 1: The termination point of this expansion line is the Used Energy End Point (UEEP) rather than the expansion line end point (ELEP). The UEEP represents the actual enthalpy of the exhaust steam, while the ELEP is a constructed quantity to allow the calculation of the enthalpy of extraction steam to the low pressure condensate heaters (if any) for which the extraction steam may be saturated.

Note 2: If a turbine test on the unit has been performed, the slope of the expansion line may be calculated by substituting actual values from the turbine test for the design values in steps 1 through 5.

6. *From the temperature and pressure of the turbine inlet steam at test conditions, determine the enthalpy, h_i and entropy, s_i, of the exhaust steam at test conditions.*
7. *Calculate the quality of the steam at the test condition by:*

$$X_T = \frac{(h_i - h_l) + m_e(s_i - s_l)}{(h_v - h_l) + m_e(s_v - s_l)}$$

where

X_T	=	*the steam quality at the turbine exhaust at test conditions,*
$h_{l,i}$	=	*the specific enthalpy of the inlet steam for the low pressure turbine*
s_i	=	*the specific entropy of the inlet steam for the low pressure turbine*
h_l	=	*the specific enthalpy of liquid water at the turbine exhaust pressure*
h_v	=	*the specific enthalpy of vapor at the turbine exhaust pressure*
Se	=	*the specific entropy of liquid water at the turbine exhaust pressure*

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6 Conclusions

The application and popularity of Air-Cooled Condensers (ACC) is increasing in the United States. There are important factors which affect the design, performance, testing and operation of an ACC. Clearly, development of appropriate design information, sensitivity to the impacts of prevailing winds, and guidelines for performance and acceptance testing are key areas of focus.

With this in mind, the Electric Power Research Institute, as part of Project EPP-P10612/C5386, has commissioned the development of a more targeted ACC specification. This paper extracts and presents some key elements of that work in progress.

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7 References

[1] Larinoff, M.W., Moles, W.E. and Reichhelm, R., "Design and Specification of Air-Cooled Steam Condensers, *Chemical Engineering,* May 22, 1978.

[2] Kröger, Detlev G., "Air Cooled Heat Exchangers and Cooling Towers", Penwell Corporation, Tulsa, OK, 2004.

[3] Wilber, K. R. and Burns, Jack. '"Examination of the Evolution and Substantiation of ASME's Proposed Test Code on Atmospheric Water-Cooling Equipment", American Society of Mechanical Engineers, Winter Annual Meeting, 1979.

[4] Wilber, K. R. and Maulbetsch, J.S., "Field Examination of Cooling Tower Testing Methodology", Cooling Tower Institute Annual Meeting, January 31-February 2, 1977.

[5] Goldschagg, H.B., "Lessons Learned form the World's Largest Forced Draft Direct Air Cooled Condenser, presented at the EPRI International Symposium on Improved Technology for Fossil Power Plants – New and Retrofit Applications, Washington, March 1993.

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SPRING CANYON, LLC

IN THE THIRD JUDICIAL DISTRICT COURT OF SALT LAKE COUNTY

STATE OF UTAH

USA POWER, LLC, USA POWER PARTNERS, LLC, and SPRING CANYON ENERGY, LLC, Plaintiff, vs. PACIFICORP, JODY L. WILLIAMS and HOLME, ROBERTS & OWEN, LLP., Defendants.	SUPPLEMENTAL AFFIDAVIT OF PEGGY A. TOMSIC IN OPPOSITION TO PACIFICORP'S AND WILLIAMS/HRO'S MOTIONS RE: SUMMARY JUDGMENT Civil No. 050903412 Judge Tyrone E. Medley

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STATE OF UTAH)
:ss.
COUNTY OF SALT LAKE)

Peggy A. Tomsic, being first duly sworn, states as follows:

1. I am the owner of Tomsic Law Firm and a member in good standing of the Utah State Bar. I am one of the lawyers who represents the plaintiffs in this action.

2. Some excerpts of deposition testimony and other supplemental documentation that were cited in the oppositions to the various motions for summary judgment were inadvertently omitted from the record I filed in opposition to the defendants' motions for summary judgment. These documents are attached to this Supplemental Affidavit, and are described in paragraphs 3-13.

3. Attached as Exhibit 1 is a true and accurate copy of excerpts from the Second Amended Complaint filed on October 21, 2005 in USA Power, LLC, et al. v. PacifiCorp, et al., Civil No. 050903412.

4. Attached as Exhibit 2 is a true and accurate copy of excerpts from PacifiCorp's 2004 Form 10-K.

5. Attached as Exhibit 3 is a true and accurate copy of excerpts from Defendants Holme Roberts & Owen, LLP and Jody L. Williams' Answers and Objections to Plaintiffs' First Set of Interrogatories.

6. Attached as Exhibit 4 is a true and accurate copy of excerpts from the deposition of Michael Jenkins.

7. Attached as Exhibit 5 is a true and accurate copy of excerpts from the deposition of Lois Banasiewicz.

8. Attached as Exhibit 6 is a true and accurate copy of excerpts from the deposition of Ted Banasiewicz.

9. Attached as Exhibit 7 is a true and accurate copy of excerpts from the deposition of Rand Thurgood.

10. Attached as Exhibit 8 is a true and accurate copy of excerpts from the 30(b)(6) deposition of Rand Thurgood.

11. Attached as Exhibit 9 is a true and accurate copy of excerpts from the deposition of Ray Racine.

12. Attached as Exhibit 10 is a true and accurate copy of excerpts from the deposition of Blaine Rawson.

13. Attached as Exhibit 11 is a true and accurate copy of excerpts from the deposition of Jody Williams.

DATED: July 23, 2007.

Peggy A. Tomsic

SUBSCRIBED and sworn to before me this 23 day of July, 2007.

Colleen Peterson

Notary Public
Residing at: Salt Lake County

Notary Public
COLLEEN PETERSON
50 South Main, Suite 1250
Salt Lake City, Utah 84144
My Commission Expires
September 26, 2008
State of Utah

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CERTIFICATE OF SERVICE

I hereby certify that on the 23 day of July, 2007, a true and correct copy of SUPPLEMENTAL AFFIDAVIT OF PEGGY A. TOMSIC IN OPPOSITION TO PACIFICORP'S AND WILLIAMS/HRO'S MOTIONS RE: SUMMARY JUDGMENT was hand delivered to the following:

Thomas R. Karrenberg, Esq.
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P. Bruce Badger
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215 South State Street, 12th Floor
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and mailed, postage prepaid, to:

Michael G. Jenkins
Assistant General Counsel
PacifiCorp
1407 West North Temple, Suite 310
Salt Lake City, Utah 84116

Colleen Peterson

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Q. Where did the water come from that PacifiCorp acquired for its project?
A. It's coming from wells approximately three miles from our project site.
Q. What is the original source of the water that PacifiCorp acquired and then had the change application to move it to its wells?
A. I don't know. Outside, it's from outside the area.
Q. It's from outside the area, correct?
A. It is. Outside the Mona, Utah drainage area, which is of great concern to us.
Q. And PacifiCorp didn't purchase any water from any of the water suppliers that either Mr. Hansen or Ms. Williams identified in any work for you, did it?
A. I don't know.
Q. Are you a licensed professional engineer?
A. I am not.
Q. Have you ever been a licensed professional engineer?
A. I have not.
Q. And you are not a hydrologist, are you, sir?
A. I am not.

Q. And you are not a water engineer, are you?
A. I am not.
Q. You don't hold yourself out as an expert in those areas, do you?
A. I do not.
Q. And that's why you hired Hansen, Allen & Luce to do work for you?
A. As well as Ms. Williams.
Q. Do you know whether Hansen, Allen & Luce performed any analysis or studies to determine whether the water that PacifiCorp was acquiring would interfere with any of the water rights owners in Juab County?
A. I do not.
Q. Do you know whether the State Engineer is required to look at that information before it grants an application to change the use and location of the water?
A. I am aware that the State Engineer is to look at that information.
Q. And the State Engineer is someone who is qualified to do that, is he not?
A. You would assume so, yes.
Q. And you testified earlier that you were invited to participate in the protests that were made

against PacifiCorp's change application?
A. I was.
Q. And you chose not to do so, didn't you?
A. We did.
Q. And there were numerous protests to PacifiCorp's change application?
A. There were.
Q. And those were all rejected by the State Engineer?
A. They were, in fact, all rejected by the State Engineer.
Q. As you sit here today, you don't have any evidence that the water that PacifiCorp is using for its plant in any way interferes or impacts your water rights?
A. That is not true.
Q. You have not performed any studies to determine the impact on your water rights of PacifiCorp's wells, have you?
A. The impact that we've been talking about is more than just whether or not water will come out of our wells. It's about the business of USA Power and the viability of our project and the theft of our confidential information.
Q. All right.

A. It's about Ms. vvilliams choosing to represent a competitor to help them obtain a very critical aspect of their development efforts.

MR. CALL: Move to strike the narrative nonresponsive answer.

MR. BADGER: I join in that objection.

Q. (BY MR. CALL) My question to you, sir, was that you don't have any evidence that PacifiCorp's wells in any way impact the quality or the quantity of your water rights?

A. I believe we do. We just differ in that.

Q. Tell me right now any way that your water rights are impacted or diminished because of PacifiCorp's wells in Juab County.

MR. PETERSEN: I'm going to object to the extent this has been asked and answered previously, but you can go ahead and answer.

THE WITNESS: It has been asked and it has been answered and I stand on my testimony.

Q. (BY MR. CALL) There are no other ways other than what you've already described on the record, sir?

A. There may be.

Q. But you don't know of any as you sit here today, do you?

A. That's correct.

Q. Now, let me ask you to please look at Exhibit 118, if you would. That's a document that was provided to you by your counsel yesterday.

A. Do I have that here? These are today's.

Q. Before we get to that, Mr. Banasiewicz, is there any problem or defect with the title to the water rights you acquired?

A. None that I'm aware of.

Q. And does Spring Canyon still have those water rights that it acquired from Keyte and Garrett?

A. They do.

Q. So Spring Canyon still has the opportunity to use or sell those water rights, doesn't it?

A. It does.

Q. And does Spring Canyon still have the option to the Keyte land?

A. It does.

Q. And so Spring Canyon still has the ability to utilize or sell that asset, doesn't it?

A. It does.

Q. And does Spring Canyon still have the air permit that it obtained from the Utah Division of Air Quality?

A. It does.

about his education and then tell you about his
professional degree?
Q. (BY MR. PETERSEN) Why don't you tell me
where you went to college and what your degree was in
and we'll go from there.
A. I went to undergraduate school at Brigham
Young University and received a Bachelor's of
Engineering degree in chemical engineering.
Q. Did you go on to graduate school?
A. I then worked for two years and then went
back to Brigham Young University where I received a
Ph.D. in chemical engineering.
Q. And when did you receive your Ph.D.?
A. 1979.
Q. And did you have any specialty within that
Ph.D., for example, did you write a dissertation on
any subject?
A. I have a dissertation that deals with coal
combustion.
Q. And is that coal combustion in automobile
engines or what type of --
A. No, in boilers.
Q. And you said you received your Ph.D. in
1979, correct?
A. Correct.

Q. What did you ‿o with that information?
You can tell me as little or --
A. We evaluated it.
Q. Were you impressed by it?
A. Yes.
Q. What type of plant was Apex 1?
A. It's a combined-cycle air-cooled plant.
Q. And how many megawatts?
A. I don't know exactly, but roughly 500.
Q. When was it built?
A. It was completed, I believe, in 2003.
What did I say when we received the material?
Q. I believe June of 2002, according to my notes.
A. That's correct. So I think it was completed in the following year.
Q. Apart from Apex 1, what other assets did you look at?
A. We looked at assets that were potentially going to be built near Mesquite, Nevada, and I don't recall the name of the project.
Q. So that was just on paper?
A. That was on paper. We talked with Arizona Public Service about their assets. We talked with -- I talked personally with a number of different

companies, with Duke, with --

Q. Duke Power?

A. Yes. Pretty much every major merchant facility at that time. I was on the phone constantly with these folks.

Q. Now, to rephrase an earlier question, was there a time when you were making all these phone calls or doing all of this investigation, was it concentrated on a particular time or was it the entire time that you were in charge of developing options?

A. It was the entire time, it was my job.

Q. Now, I notice that Apex 1 and some of these others were not mentioned in the IRP, at least that I could see.

A. That's correct.

Q. Why were they not mentioned?

A. We decided that we didn't have transmission sufficient to get that energy up to the Wasatch Valley -- or the Wasatch Front.

Q. When did you make that decision?

A. I don't know that there was a distinct point in time. It still was considered along the whole process of these years that you're talking about.

that were set out for anyone that wanted to bid on that contract; is that correct?
A. Yes.
Q. So my question is, did the cost-based alternative have those same requirements?
A. Well, I'm not sure that I could go specifically and answer. If you wanted to ask specific questions about each one, maybe I could answer them.
MR. BADGER: Let me object that it lacks foundation, it's vague and ambiguous.
Q. (BY MR. PETERSEN) Do you understand my question?
A. Yes. But I don't understand -- I'm not going to give a specific answer that encompasses the whole of it because I'm not understanding all that's there. If you want to lead me through I'll be happy to answer the question.
Q. All right. Let me start with a really basic question. The due date for a response on this RFP, Exhibit 5, was July 22, 2003?
A. Correct.
Q. Was it your understanding that the cost-based alternative had to be submitted by July 22, 2003?

A. Yes, it did. It was submitted on July the 17th.
Q. All right. And once again, going back to page 3, I'm looking at the different resource requirements and, for example, one, it speaks to a 200-megawatt peaker project; do you see that?
A. Yes.
Q. And then on the next page it talks about the supply block size. Do you see that?
A. I do.
Q. And it speaks to the delivery start date which is April 2005; do you see that?
A. I do.
Q. And then it speaks to the comment that PacifiCorp's option to call upon generation daily?
A. Yes.
Q. Now my question is, did the cost-based alternative have to conform with those requirements?
A. Yes.
Q. Next, turning to page 5, and it speaks to a Schedule of RFP Actions laid out there. Do you see that?
A. I do.
Q. And once again, was that a timetable that the cost-based alternative had to conform to?

project?
A. No. They indicated they would like to have a meeting with us and were interested to know whether we would sign a confidentiality agreement.
Q. This is on the first conversation?
A. Yes, sir.
Q. How did you respond to that?
A. We would be interested to talk to them and would be willing to sign an agreement that met with our needs and policies.
Q. Do you all have a policy on confidentiality agreement?
A. Not a specific policy that I'm aware of, but we do have to review those through our Legal Department.
Q. After this first conversation with what I'm going to call USA Power, since you didn't specify the particular person, did you have any internal conversations within PacifiCorp?
A. Yes.
Q. Who did you speak with?
A. I spoke with my group about them to inquire as to whether they had ever heard of them before.
Q. Did you speak to the whole group at one

time or did you speak to them individually?
A. I don't remember.
Q. Had anyone heard of them before?
A. No, sir.
Q. Did you do any further research or follow-up in terms of their group?
A. We did.
Q. What did you do?
A. It had been indicated in the initial conversation that they had an air permit. So I asked Ian Andrews to look into that. He went to the Division of Air Quality and secured a copy of the air permit.
Q. At that time did they have an air permit?
A. They had an application, an NOI on file, as I recall.
Q. When you spoke to that person in that first phone call, do you remember what name they used for their entity, or did they use a name?
A. I don't remember which of the three names they used.
Q. After that initial phone conversation, what happened next? And when I say "what happened next," I don't want to be overly vague, but did you have a follow-up conversation or a follow-up meeting?

A. We did.
Q. And what was the tenor of that discussion?
A. That they would come back with a confidentiality agreement and we would then pursue further discussion.
Q. Did there come a time when they sent you a confidentiality agreement?
A. I don't remember it being sent. I remember ultimately getting it, and I believe it was in a meeting.
Q. Let me get to that in a second. After the meeting, which I'm going to call the August 22nd meeting just for purposes of putting a date on it, after that meeting what was your next communication with USA Power?
A. I believe it was in September when they came and met with us.
Q. Between the September and the August meeting were there any phone conversations?
A. I don't recall.
Q. Did your group do any further research on their project?
A. Other than to get the air -- the NOI filing, no.
Q. The NOI filing?

A. The air permit filing.
Q. Why did you get the NOI filing?
A. We wanted to know what was in the permit.
Q. Why did you want to know that?
A. To see just how valid the project was.
Q. At that time, which is to say September of 2002, did you evaluate the validity of the project?
A. We began that process. And by "process," I mean we began to look at the NOI filing, we took into consideration what they had said in the meetings. And if you term that evaluation, then that's as far as we went.
Q. Did you actually reach a conclusion at that point?
A. No. We didn't have sufficient information.
Q. Did you have a specific staff member that was tasked with evaluating the validity of what I'll call Spring Canyon?
A. No, sir.
Q. Was it your entire group that participated?
A. It was members of my group.
Q. Do you recall when the next meeting occurred?

Q. Do you remember what details were shared with you on September 11?
A. No, I do not.
Q. How long did the meeting last?
A. I don't recall.
Q. Do you remember who was there on behalf of PacifiCorp?
A. I do not. Myself, I know I was there, obviously. I don't recall exactly who else was there.
Q. Did you all talk about a potential transaction between PacifiCorp and USA Power?
A. We did.
Q. And did you talk about one type of transaction or different types of transactions?
A. I believe we talked about several different possibilities.
Q. And do you remember which possibilities you discussed?
A. From a power purchase agreement to an equity position.
Q. Did you talk about any other possibilities besides those two?
A. Not that I remember.
Q. In regard to the power purchase agreement,

Tab 2

A. The second letter, okay, is the subject of this, is the performance analysis and alternative equipment configurations, so we were looking at the alternative of perhaps entering into a staged construction instead of building a two-on-on one plant all at once, to install one gas turbine and one steam turbine initially, and then a second one-on-one train would go in next to it at a future date.

And as I recall, this had something to do with power purchase agreement for about half of the plant output versus selling the entire plant output of 500 megawatts in one deal.

Q. The -- and I know Mr. Badger earlier asked you some questions about cost details, so I'm not going to run through all that again, but on balance, Exhibit 348, did that represent work product that you had put into this project?

A. It's a summary of information that we had developed up to that point in time, yes.

Q. And as of this point, which is to say July 1, 2002, how long had your team been working on this project?

A. Well, since at least April of '01, spring of '01.

Q. The information that is contained in Exhibit 348 that you put together, was this information that your team considered confidential work product?

A. Yes, it was held confidential for the client. It's client's information, and as such is confidential.

Q. And was it information that you had developed over the preceding year?

A. Yes.

Q. Let me turn to --

A. Could I just add, it's confidential to the extent that the client wishes to keep it confidential. It's his option, of course, to, you know, discuss it with anyone he sees fit to.

Q. Sure

But did you consider it within your shop confidential?

A. Yes, we would have no reason to discuss this information outside of the work we were doing with Ted and Dave.

Q. Okay.

Could you identify 349, please?

(Discussion off the record.)

BY MR. PETERSEN·

Q. Mr Racine, you're looking what -- at what has previously been designated Exhibit 322.

Do you see that?

A. Yes.

Q. And I think you testified a moment ago about a letter you prepared?

A. Right.

Q. Do you recollect that testimony?

A. Right.

Q. Now that you're looking at 322, does that --

A. Right.

Q. -- help you focus --

A. Right. Yes, it does. I thought this was part of the other one.

Q. And I know you've testified earlier this morning and it's late in the day, but very briefly can you describe the context in which you prepared Exhibit 322?

MR. BADGER. Objection. Asked and answered

MR. PETERSEN. You can answer again, sir.

THE WITNESS. The question was put to me by Dave Graeber about the relative performance of the plant, wet versus dry cooling, and the issue was that apparently PacifiCorp did not agree that the plant performance that we were predicting was attainable by using a dry-cooling tower, and I believe there was a fellow by the name of Grant Thurgood who was mentioned, and we were in the process of setting up for a conference call with him following the preparation of this document and forwarding to Dave, but to my recollection, that conference call never -- never occurred

However, I do seem to recall that the subject was discussed further with Quixx, with Randy Allison at Quixx, who was investigating the same issue, and that is evaluating whether or not technically an air-cooled plant would be able to achieve the kind of performance that we're predicting

1400

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BY ______
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USA POWER PARTNERS, LLC;
SPRING CANYON, LLC

IN THE THIRD JUDICIAL DISTRICT COURT OF SALT LAKE COUNTY

STATE OF UTAH

USA POWER, LLC, USA POWER PARTNERS, LLC, and SPRING CANYON ENERGY, LLC, Plaintiff, vs. PACIFICORP, JODY L. WILLIAMS and HOLME, ROBERTS & OWEN, LLP., Defendants	SUPPLEMENT TO AFFIDAVIT NO. 3A OF PEGGY A. TOMSIC IN OPPOSITION TO PACIFICORP'S AND WILLIAMS/HRO'S MOTIONS RE: SUMMARY JUDGMENT (BATES STAMPED DOCUMENTS) Civil No. 050903412 Judge Tyrone E. Medley

64113

STATE OF UTAH)
:ss.
COUNTY OF SALT LAKE)

Peggy A. Tomsic, being first duly sworn, states as follows:

1. I am the owner of Tomsic Law Firm and a member in good standing of the Utah State Bar. I am one of the lawyers who represents the plaintiffs in this action.

2. Some bates stamped documents that were cited in the oppositions to the various motions for summary judgment were inadvertently omitted from the record I filed in opposition to the defendants' motions for summary judgment. These documents are attached to this Supplemental Affidavit, and are described in paragraphs 3-4.

3. Attached as Exhibit 9 is a document Bates numbered HRO-00063-64.

4. Attached as Exhibit 10 is a document Bates numbered HRO-PC 001425-1430.

DATED: July 23, 2007.

Peggy A. Tomsic

SUBSCRIBED and sworn to before me this 23 day of July, 2007.

Colleen Peterson
Notary Public
Residing at: Salt Lake County

Notary Public
COLLEEN PETERSON
50 South Main, Suite 1250
Salt Lake City, Utah 84144
My Commission Expires
September 28, 2008
State of Utah

CERTIFICATE OF SERVICE

I hereby certify that on the 23 day of June, 2007, a true and correct copy of SUPPLEMENTAL AFFIDAVIT NO. 3 OF PEGGY A. TOMSIC IN OPPOSITION TO PACIFICORP'S AND WILLIAMS/HRO'S MOTIONS RE: SUMMARY JUDGMENT (BATES STAMPED DOCUMENTS) was hand delivered to the following:

Thomas R. Karrenberg, Esq.
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P. Bruce Badger
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and mailed, postage prepaid, to:

Michael G. Jenkins
Assistant General Counsel
PacifiCorp
1407 West North Temple, Suite 310
Salt Lake City, Utah 84116

Colleen Peterson

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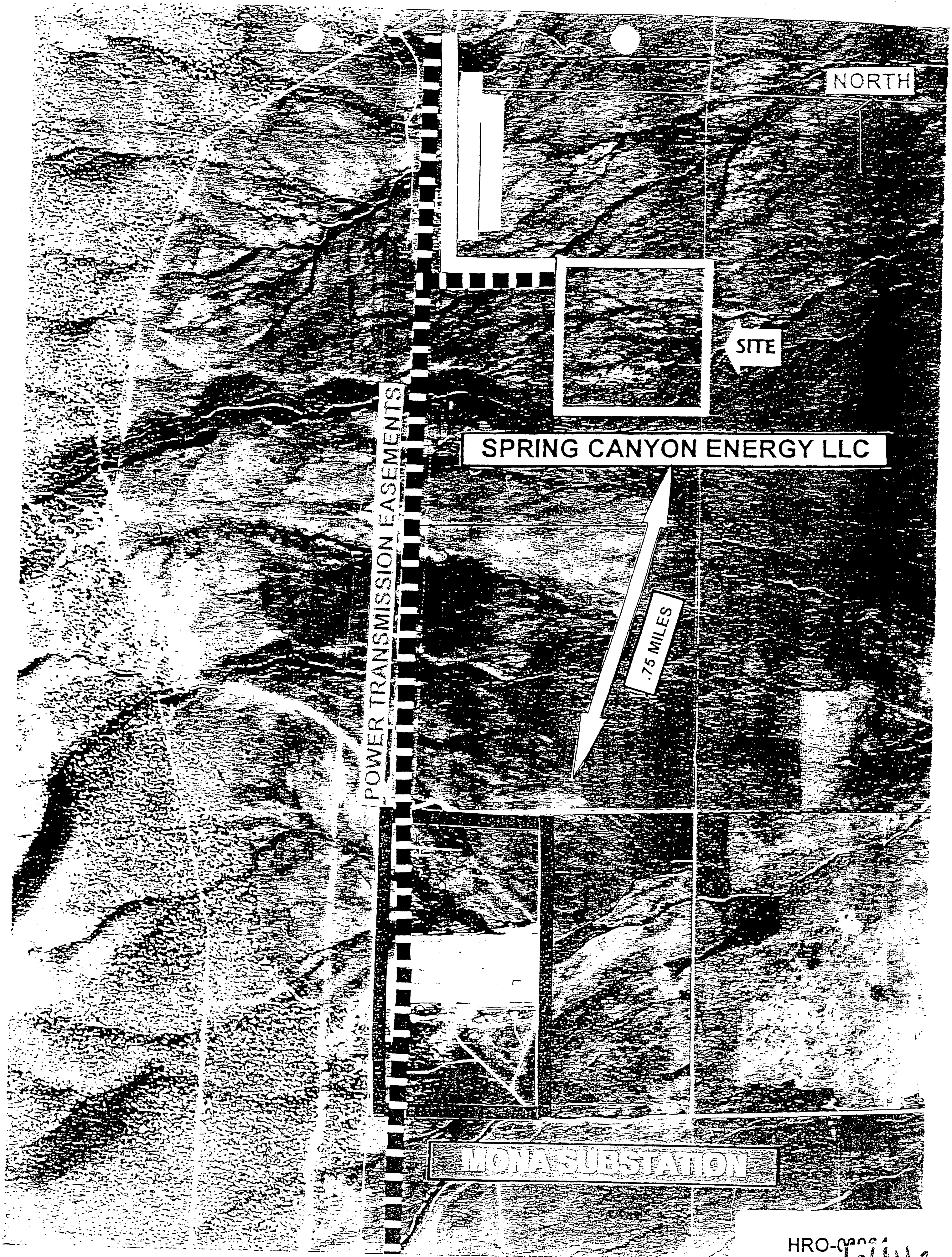
POWER TRANSMISSION EASEMENT
NORTH
GAS PIPELINE EASEMENT
MONA RESERVOIR
SITE
SPRING CANYON ENERGY LLC
MONA SUBSTATION
MONA


NORTH
SITE
SPRING CANYON ENERGY LLC
.75 MILES
POWER TRANSMISSION EASEMENTS
MONA SUBSTATION

T64116

EXHIBIT 10

16417

8-6-03

Bruce F., Grant Cooper, Will,
Rand, Merrill, Claudia, Jody

5. Agreed on pmt, — agreed on 270/sh. fixed pmt.

Timing + firm supply are key terms.

6. No need to remove equipment

7. Bruce - improvident.
Indemnity - sig. endangered species on property owned by Church. No need for it.

8. Wells on Pacif. property.

9. They will prepare change. We will work together. We will share costs
Mona is ~~the~~ our area.
Goshen is theirs

They pay filing fee. Costs of lit is their concern.

Grant - the water right Talked to Bruce.

HRO-PC 001425

" " " re. protest process 10418

provides assurance itself.
What water right? -
Main right =
21,978 af / 53-995
495 acres / 53-75
flow right in underground
well. Not subservient to Goshen Irrig. Co.
Stored year round & discharged

Ask Current Creek Irrig. to distinguish
gw & surface water. Create class of
shares for ind. use.
Get out of dam management.

gw = 10% of Co. rights

If put up surface right, second priority.
Problem in high water years.
If straight CC irrig. shares —

Bruce - seg gw & rely on it.

Jody - back off acreage at Church Farms
to supply plant in extended
drought or dry year.

Rand - If I own water, I will take risk. If I lease water, I only have a contract.

Governance Issues

Rand - Risk Form + Risk Review Process

2400 acres of sole supply irrig r+ along w/ CC Irrig.

Rand:

1. You deal w/ Current Creek
2. You seg. water
3. We both prepare change
4. Prosecute change
5. Pacif in charge of well

Rand - how long will it take?

Bruce - 2 to 3 month to deal w/ Current Creek.

A → Jody - understand Utah lake Plan.

Grant 2 months publication + protest
3 months hearing
3 months Current Creek

HRO-PC 001437 10U2C

Rand - drill provisional well & pump test.

Grant - won't turn you off.

Rand - I have to re-think this. I'll get back to you.

Grant - You worry about Mona.
- We worry about CC
- No one worries about Goshen.

Merrill - Mona Irrig. has big well 3/4 mile from our well. Met Gordon Young.
If we run 900 gpm we draw them down 3 feet. We expect to operate at 600 gpm.

Other power plant?

Rand - RFP out because of IRP
200 MW peak 2005
500 " " baseload 2007

HRO-PC 001428

Since IRP, more growth. 0421

July 22 proposals in. End of next week will

announce the screen cut.
Pacif plant is cost based alternative.
Others can be merchant plant, own financing.

Transmission Nevada-up-Red Butte — some capacity there
Montana down is full.

After screen cut, will be unblinded

Utah County is non-attainment area.

Finch Farm

Current Creek

File change on shares with all sources.

Or - buy Utah lake water, drill well ~~of~~ for Goshen, get their early right

995
115
996
75

— all Current Creek rights

Place of use
Location of wells
Explanatory

COPY OF TRANSCRIPT

IN THE THIRD JUDICIAL DISTRICT COURT
OF SALT LAKE COUNTY, STATE OF UTAH

USA POWER, LLC; USA POWER PARTNERS, LLC; and SPRING CANYON ENERGY, LLC,	Deposition of:
	MICHAEL JENKINS
Plaintiffs,	
vs.	Civil No 050903412
PACIFICORP, JODY L WILLIAMS and HOLME, ROBERTS & OWEN, LLP,	Judge Tyrone E. Medley
Defendants.	

April 19, 2006 * 9.30 a.m.

Location TOMSIC & PECK
Attorneys at Law
136 East South Temple, Suite 800
Salt Lake City, Utah 84111

Reporter: LANETTE SHINDURLING, RPR, CRR
Notary Public in and for the State of Utah

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prior to the initiation of this
litigation consider the issue of
whether Ms. Williams or Holme, Roberts
& Owen had a conflict of interest in
representing PacifiCorp relative to
Currant Creek?")

MR. BADGER: One other objection. To the extent that it calls for work product, we invoke that doctrine and object on that basis and the witness is instructed not to answer. He may otherwise answer the question.

THE WITNESS: Not that I can recall.

Q. (BY MS. TOMSIC) When you found out that USA Power had submitted a proposal in response to RFP 2003-A which is Exhibit 5, did you ever consider whether their submission of a proposal created a conflict of interest in Ms. Williams representing PacifiCorp relative to Currant Creek?

MR. BADGER: Objection. To the extent that the question requires this witness to testify concerning privileged attorney-client communications or to reveal his mental impressions and work product, we object on these bases and the witness is instructed not to answer. He may otherwise answer the question.

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THE WITNESS: No.

Q. (BY MS. TOMSIC) When you found out that USA Power had intervened in the Public Service Commission proceeding and was objecting to the issuance of the CCN for Currant Creek, did you ever consider whether Jody Williams and Holme, Roberts & Owen had a conflict of interest in representing PacifiCorp relative to Currant Creek?

MR. BADGER: Object to the extent it calls for attorney-client privileged communications and instruct the witness not to answer. He may otherwise answer the question.

THE WITNESS: No.

Q. (BY MS. TOMSIC) What was your understanding in 2003 as to what the scope of Jody Williams' representation of PacifiCorp was relative to Currant Creek?

A. To assist the company in acquiring water rights that could be used for the Currant Creek project.

Q. And was it your understanding during 2003 that obtaining water rights was necessary for the Currant Creek project to be constructed and operated?

A. Yes.

Q. And during 2003 did you also understand that once PacifiCorp made the decision to build Currant Creek that it was not going to accept any of the proposals submitted by USA Power relative to the Spring Canyon project?

MR. CALL: Objection, assumes facts not in evidence.

MR. BADGER: Objection. To the extent it calls for the witness to testify concerning attorney-client communications, he's instructed not to answer. He may otherwise answer the question.

THE WITNESS: My understanding was that once the Currant Creek project was selected that no other responses to that RFP would be selected, although there would be later opportunities to bid into other RFPs.

Q. (BY MS. TOMSIC) And one of the proposals about which you just now testified would have been the proposal submitted by USA Power in response to RFP 2003-A?

A. That's correct.

MS. TOMSIC: Why don't we take a five-minute break and I'll just look at my notes. I think I'm either done or pretty dang close.

(Recess taken.)

Q. (BY MS. TOMSIC) Mr. Jenkins, did you

REPORTER'S CERTIFICATE

STATE OF UTAH)
: ss.
COUNTY OF SALT LAKE)

I, LANETTE SHINDURLING, Registered Professional Reporter, Certified Realtime Reporter and Notary Public in and for the State of Utah, do hereby certify

That prior to being examined, the witness, MICHAEL JENKINS, was by me duly sworn to tell the truth, the whole truth, and nothing but the truth,

That said deposition was taken down by me in stenotype on April 19, 2006, at the place therein named, and was thereafter transcribed and that a true and correct transcription of said testimony is set forth in the preceding pages;

I further certify that, in accordance with Rule 30(e), a request having been made to review the transcript, a reading copy was sent to P. BRUCE BADGER, ESQ. for the witness to read and sign before a notary public and then return to me for filing with PEGGY A. TOMSIC, ESQ.

I further certify that I am not kin or otherwise associated with any of the parties to said cause of action and that I am not interested in the outcome thereof.

WITNESS MY HAND AND OFFICIAL SEAL this 17th day of May, 2006.

Lanette Shindurling

LANETTE SHINDURLING, RPR, CRR
Utah License No. 103865-7801

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COPY OF TRANSCRIPT

IN THE THIRD JUDICIAL DISTRICT COURT

OF SALT LAKE COUNTY, STATE OF UTAH

USA POWER, LLC; USA POWER PARTNERS, LLC; and SPRING CANYON ENERGY, LLC,	Deposition of:
	J. RAND THURGOOD
Plaintiffs,	VOLUME I
vs.	
	Civil No. 050903412
PACIFICORP, JODY L. WILLIAMS and HOLME, ROBERTS & OWEN, LLP,	Judge Tyrone E. Medley
Defendants.	

January 19, 2006 * 9:30 a.m.

Location: TOMSIC & PECK
Attorneys at Law
136 East South Temple, Suite 800
Salt Lake City, Utah 84111

Reporter: LANETTE SHINDURLING, RPR, CRR
Notary Public in and for the State of Utah

we were acquiring. And so the answer to that would be yes. And then we had, of course, at our leisure the time to look over it very carefully after that once it had been purchased.

Q. Did you sign a nondisclosure agreement with them before the purchase?

A. We did.

Q. You did?

A. We did.

Q. When did you actually put your eyes on that information?

A. I do not recall explicitly. It may have been before Christmas or the first part of the year of 2003, but I don't remember the exact time frame.

Q. All right. Let me ask you on a separate tack. You spoke about your initial meeting with Ms. Williams I believe at your office in 2003?

A. I think I correctly stated that it was probably in my office, but I wasn't sure.

Q. And you testified that you asked her whether or not she had a conflict of interest, correct?

A. That's correct.

Q. Did anyone in PacifiCorp instruct you or did anybody instruct you to ask that question?

A. No.
Q. So you did that on your own initiative?
A. I did.
Q. Was there any type of company policy that you were following in asking that question?
A. No. But it was part of our training and what we had done over the years with any legal situation that we thought might potentially have a problem for us.
Q. What type of training are you talking about?
A. Periodically the company offered legal training to the management talking about a variety of different things that had to do with the proprietary nature of legal contracts. I mean, just general contract law.
Q. Do you remember who performed that training?
A. No. It was varied. Different people offered different -- and I couldn't give you any time frames. It was just throughout my career.
Q. Was it the corporate counsel of PacifiCorp that would, for example, hold that?
A. It was not specifically, no.
Q. Did you follow up with anyone else,

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especially anyone else at PacifiCorp, regarding this conflict of interest issue?

A. I did.

Q. Who did you follow up with?

A. Mike Jenkins.

Q. And when did you have that follow-up?

A. Upon finishing the conversation with Jody.

Q. Did you call him?

A. No. He was officed right near me. I spoke with him.

Q. Do you remember the substance of that conversation?

MR. BADGER: I'm going to object. That's getting into attorney-client privilege and he's not to answer that.

Q. (BY MR. PETERSEN) All right. Let me see if I can kind of draw some boundaries around this conversation. You had a communication with Mr. Jenkins on that issue; is that correct?

A. That's correct.

Q. Based on that communication, did you take any further steps?

A. No.

Q. Did you tell Mr. Jenkins that you had seen a document from Spring Canyon that mentioned Ms.

Williams' name?

MR. BADGER: I'm going to object. I think we're getting into -- what he told Mr. Jenkins is part of that confidential communication and I'm going to object, attorney-client privilege, and instruct the witness not to answer.

MR. PETERSEN: Why don't we do this. I will ask the questions and proffer them and then you can make the objections that you want.

MR. BADGER: Fine.

Q. (BY MR. PETERSEN) Did Mr. Jenkins advise you to take any follow-up steps in regard to this conflict of interest issue?

MR. BADGER: Objection, attorney-client privilege. The witness is instructed not to answer.

Q. (BY MR. PETERSEN) Did you have any other conversations with Mr. Jenkins or anyone else at PacifiCorp about this issue?

A. No.

Q. One additional question. What, and I'm just putting this on the record, what advice did you get from Mr. Jenkins in regard to this issue?

MR. BADGER: Objection, attorney-client privilege. The witness is instructed not to answer.

MR. PETERSEN: All right. Hold on one

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THIRD JUDICIAL DISTRICT
SALT LAKE COUNTY

BY DEPUTY

FILED DISTRICT COURT
Third Judicial District

AUG - 1 2007

SALT LAKE COUNTY

By Deputy Clerk

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IN THE THIRD JUDICIAL DISTRICT COURT FOR SALT LAKE COUNTY

STATE OF UTAH

USA POWER, LLC, USA POWER PARTNERS, LLC and SPRING CANYON ENERGY, LLC, Plaintiffs, **vs.** **PACIFICORP, JODY L. WILLIAMS and HOLME, ROBERTS & OWEN, LLP,** Defendants.	**REPLY MEMORANDUM IN SUPPORT OF MOTION FOR PARTIAL SUMMARY JUDGMENT RE: LOYALTY CLAIM** Civil No. 050903412 The Honorable Tyrone E. Medley **(Hearing Requested)**

Defendants Holme Roberts & Owen, LLP ("Holme Roberts") and Jody L. Williams ("Williams") (collectively "Holme Roberts") submit this Reply Memorandum in Support of their Motion for Partial Summary Judgment RE: Loyalty Claim.

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they mutually exclusive. The only thing that stopped Plaintiffs from developing their project was Plaintiffs' own limitations. Holme Roberts did not breach any duty of loyalty by simply helping PacifiCorp acquire water for its separate and different project.

II. PLAINTIFFS HAVE PRESENTED NO EVIDENCE THAT ANY ALLEGED BREACH OF HOLME ROBERTS' DUTY OF LOYALTY CAUSED ANY INJURY OR DAMAGES TO PLAINTIFFS.

Even if Plaintiffs could produce evidence that Holme Roberts somehow technically breached the duty of loyalty, summary judgment would still be appropriate because Plaintiffs have no evidence even *remotely* suggesting that Holme Roberts' alleged breach could have caused Plaintiffs any injury or damages.

Paragraph 93 of Plaintiffs' statement of facts asserts that PacifiCorp terminated its negotiations with Plaintiffs "as a direct result of Williams/HRO's representation of PacifiCorp," but this is entirely unsupported by any evidence.[5] (Pls.' Mem. at lxxxiv-lxxxv, ¶ 93.) Plaintiffs further assert that PacifiCorp "would have purchased the Spring Canyon assets" if Williams had not assured PacifiCorp that she could find water rights for PacifiCorp (*Id.* ¶ 94). But again, Plaintiffs failed to cite any evidence supporting this allegation.[6] Paragraph 97[7] also alleges that

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[5] To support this allegation, Plaintiffs cite pages 287-88 of Ted Banasiewicz's deposition, pages 143 and 245 of Lois Banasiewicz's deposition, and page 12 of the report from J. Robert Malko. None of these sources say anything to suggest that PacifiCorp's termination of negotiations was a "direct result" of Holme Roberts' representation of PacifiCorp. While the two depositions discuss the termination of the negotiations, and the Malko Report purports to discuss the amount of damages from the termination, none of these sources ties the termination to the representation. In fact, the cited sources do not mention Holme Roberts or the representation at all.

[6] Plaintiffs cite Deposition Exhibits 46, 47, 68 and 110 (pages 16-17 and 148) and pages 211-227 of Rand Thurgood's deposition to support paragraph 94. Once again, however, these exhibits and deposition excerpts do not show that any assurance by Williams caused PacifiCorp to forego buying the Spring Canyon assets. These documents merely show that water was important for the project, and that PacifiCorp asked Williams to help find some.

[7] Paragraph 95 merely asserts that PacifiCorp needed a firm water source to build a plant. This is probably true, but has nothing to do with Holme Roberts. Paragraph 96 alleges that PacifiCorp could not have "developed" the Currant Creek project without Plaintiffs' *confidential information*, but as established in Holme Roberts' prior summary judgment motion, there is no evidence that Holme Roberts ever conveyed any confidential information to PacifiCorp. Indeed, pages 14-16 of the Koltick Report, which Plaintiffs cite to support this allegation, do not say

"[a]s a direct result of Williams/HRO's representation of PacifiCorp on the Currant Creek project, USA Power was not awarded the RFP to supply power to PacifiCorp beginning in March 2005"; once again, however, the evidence cited does not support the allegation.[8]

Instead of providing actual evidence of causation, Plaintiffs invite the Court to speculate that because Holme Roberts helped PacifiCorp obtain water, and because water was ultimately necessary for the project, Holme Roberts' representation is to blame for Plaintiffs' failure to sell the Spring Canyon assets to PacifiCorp. This reasoning fails, however, on several levels.

A. It is undisputed that Holme Roberts' representation was not necessary for PacifiCorp to acquire water rights for Currant Creek.

Most importantly, while PacifiCorp ultimately needed water for the Currant Creek project, there is no evidence that *Holme Roberts'* services were necessary for PacifiCorp to obtain water. Michael G. Jenkins, the Assistant General Counsel of PacifiCorp Energy, testified that as of March 2003, he was familiar with "several" other law firms and attorneys with water law expertise, and that he was prepared to contact other water law counsel in Salt Lake City who were "equally capable of assisting PacifiCorp with that assignment." (Jenkins Aff. at ¶¶ 2-3,

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anything about *Holme Roberts* at all. Rather, the report discusses "the Confidential Information *Plaintiffs provided to PacifiCorp*." (Koltick Report, Ex. 3 to Tomsic Aff. 4, at 14 (emphasis added).)

[8]As purported support for paragraph 97, Plaintiffs cite pages 407-410 and 580-81 of Ted Banasiewicz's deposition, pages 14-17 of the Koltick Report and pages 4-6 of the Morris Report. Ted Banasiewicz's testimony consists of nothing but unsupported accusations. As there is no evidence that Ted Banasiewicz has personal knowledge of either Williams' dealings with PacifiCorp or the effect those dealings had on PacifiCorp's decision-making process, his testimony in this regard is inadmissible, and thus not sufficient to raise a genuine issue of material fact on those matters. *See* Utah R. Civ. P. 56(e) (Affidavits "shall be made on personal knowledge, shall set forth such facts as would be admissible in evidence, and shall show affirmatively that the affiant is competent to testify to the matters stated therein."); Utah R. Evid. 602 ("A witness may not testify to a matter unless evidence is introduced sufficient to support a finding that the witness has personal knowledge of the matter."). The two expert reports are similarly insufficient to support the allegation in paragraph 97. John Morris does *not* say that Holme Roberts' representation of PacifiCorp caused Plaintiffs to lose the Spring Canyon deal. In fact, he states that "[w]hether such use or disclosure [of confidential information] occurred is an issue for the trier of fact." (Morris Report at p. 6.) Similarly, as described in the preceding footnote, Mr. Koltick states only that PacifiCorp could not have developed the project in a short time without "[t]he Confidential Information *Plaintiffs provided to PacifiCorp*." (Koltick Report at p. 15 (emphasis added).) This portion of Mr. Koltick's report does not say anything about Holme Roberts.

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deliver this power, i.e., in Mona Utah. (*Id.* at p. 18.) Based on this record, it would be purely speculative for a jury to conclude that PacifiCorp's choice not to buy power from Plaintiffs in 2003 somehow prevented Plaintiffs from being able to develop and profit from the Spring Canyon project.

Plaintiffs' claim that Holme Roberts' representation of PacifiCorp caused Plaintiffs to suffer damages is purely speculative at every step of the argument. And because damages are purely speculative, Plaintiffs are not entitled to continue forcing Holme Roberts to defend against Plaintiffs' claim that Holme Roberts breached its fiduciary duty.

CONCLUSION

Plaintiffs are simply casting around, looking for someone to blame for the failure of their business plan. But there is no evidence that any blame can rightfully be cast in Holme Roberts' direction. There is no evidence that (1) Holme Roberts breached any duty to Plaintiffs, or (2) that any such breach could have caused Plaintiffs to suffer any compensable damages. Accordingly, Holme Roberts respectfully requests that the Court grant partial summary judgment, dismissing with prejudice Plaintiffs' claim for breach of the fiduciary duty of loyalty.

DATED this 27th day of July, 2007

ANDERSON & KARRENBERG

Scott Call

Thomas R. Karrenberg
Scott A. Call
Stephen P. Horvat
Jennifer R. Eshelman
Attorneys for Defendants Holme Roberts & Owen and Jody L. Williams

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CONDENSED TRANSCRIPT

IN THE THIRD JUDICIAL DISTRICT COURT

SALT LAKE COUNTY, STATE OF UTAH

USA POWER, LLC; USA POWER PARTNERS, LLC; and SPRING CANYON ENERGY, LLC, Plaintiffs, vs. PACIFICORP, JODY L. WILLIAMS and HOLME ROBERTS & OWEN, LLP, Defendants.	Deposition of: Lois Banasiewicz Volume II Civil No. 050903412 Hon. Tyrone E. Medley

August 2, 2006 * 9:07 a.m.

Location: Fabian & Clendenin
215 South State Street, Suite 1100
Salt Lake City, Utah

Reporter: Susette M. Snider, CSR, RPR, CRR
Notary Public in and for the State of Utah

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SHEET 7

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Q. (By Mr. Badger) I think what you've told me is that your understanding was that there was a contract for $3 million but not a contract for a long-term development agreement.
A. That's correct.
Q. What happened in the negotiations after -- we stopped -- we went as far as March 1, 2003, and you told me about Rand talking to Ted about $3 million and a long-term development agreement.
Now, what was the next step in the negotiations after that?
A. We got in the car and drove to Portland with an anticipation to meet with Rand Thurgood and other parties from -- from Portland -- from PacifiCorp in Portland to close that transaction. We arrived in Portland, I believe, on the 16th, and on the morning of the 18th we -- we received a voice message, a voice mail message from Rand Thurgood stating that his upper management did not want to proceed with the purchase of the Spring Canyon Energy assets and encouraged us to participate in the RFP.
Q. What was the next step in the course of negotiations?
A. After that voice mail, Ted tried to reach Rand several times, and on the 20th of March both

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Rand and Ted had a conversation regarding PacifiCorp's decision not to proceed with the Spring Canyon Energy project assets.
Q. How do you know that a conversation took place? Were you part of it?
A. I -- I was not part of it, but I did witness my husband making that call -- receiving that call.
Q. Where were you?
A. We were in Portland.
Q. At a hotel or --
A. Yes, we were, um-hum. That was the Marriott.
Q. Who else was present when Ted was on the phone?
A. Just myself.
Q. What did you hear him say?
A. I believe he -- as I remember right now, he discussed with Rand the reasons why PacifiCorp management decided to terminate the negotiations for the Spring Canyon Energy project. I also heard Ted speak of the RFP and the RFP process, and that was the direction that PacifiCorp had intended to move into.
Q. After -- have you completed your answer?

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A. No, I have not finished.
Q. I'm sorry. I apologize.
A. Rand provided to Ted the information regarding the RFP prebid meeting, and Rand stated to Ted that Spring Canyon Energy's bid was their bid to lose -- was our bid to lose in the RFP because we were -- our advantage that we had with the advance of our development with Spring Canyon Energy.
Q. It sounds as though you were listening in on this conversation, but you were not, were you?
A. No, I was not. I heard my husband speak to Rand, and then immediately after the call, Ted reviewed the points of the conversation that Rand made with Ted.
Q. This language about your bid to lose, did Ted tell you that's what Rand Thurgood had said to him?
A. That's correct.
Q. Now, have you completed your answer to that question?
A. Also, Ted verbally asked Rand, since we're not proceeding with the sale of the Spring Canyon Energy assets, to return all of our materials, Volume 1, 2 and 3, and also the materials we provided via fax to him regarding the technical information and

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also asked Rand to request the same of Stacey Kusters of the information that we provided to her team.
Q. What technical materials were --
A. We had --
Q. Hang on. Hang on.
A. Sure.
Q. You know what I'm asking, but let me make sure I --
A. Um-hum. Okay.
Q. -- don't muddle my own question.
A. That's -- I'm sorry.
Q. In your last answer you said that Mr. Banasiewicz had asked Mr. Thurgood to return, I think, all faxed technical materials. What would that refer to?
A. That would refer to a letter that we provided to Rand Thurgood from Ray Racine from Waldron Engineering, W-a-l-d-r-o-n, in particular.
Q. What materials had been provided to Stacey Kusters?
A. We provided to Stacey Kusters a letter agreement, a draft power purchase agreement and also the two option agreements that we put together based on Rand's request.
Q. None of those were ever signed by

lelol5

REPORTER'S CERTIFICATE

STATE OF UTAH)
) ss.
COUNTY OF SALT LAKE)

I, Susette M. Snider, Registered Professional Reporter and Notary Public in and for the State of Utah, do hereby certify:

That on August 2, 2006, prior to being examined, the witness, Lois Banasiewicz, was duly sworn by me to tell the truth, the whole truth, and nothing but the truth;

That the testimony of said witness was reported by me in stenotype and thereafter transcribed, and that a full, true, and correct transcription of said testimony is set forth in the preceding pages;

That in accordance with Rule 30(e), no request having been made for the witness to read and sign the transcript, the original transcript was sealed and delivered to Scott A. Call, Attorney at Law, for safekeeping.

I further certify that I am not kin or otherwise associated with any of the parties to said cause of action and that I am not interested in the outcome thereof.

WITNESS MY HAND AND OFFICIAL SEAL this 16th day of August, 2006.

Susette M. Snider, RPR, CRR
Notary Public
Residing in Salt Lake County

FILED DISTRICT COURT
Third Judicial District
AUG - 1 2007
SALT LAKE COUNTY
By ______ Deputy Clerk

P. Bruce Badger (A4791)
Peter W. Billings (A0330)
Kevin N. Anderson (A0100)
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Attorneys for Defendant PacifiCorp

IN THE THIRD DISTRICT COURT

SALT LAKE COUNTY, STATE OF UTAH

USA POWER, LLC; USA POWER PARTNERS, LLC; and SPRING CANYON ENERGY, LLC, Plaintiffs, vs. PACIFICORP; JODY L. WILLIAMS and HOLME, ROBERTS & OWEN, LLP, Defendants.	**REPLY MEMORANDUM IN SUPPORT OF PACIFICORP'S MOTION FOR SUMMARY JUDGMENT** Civil No. 050903412 Judge Tyrone E. Medley

PacifiCorp submits its Reply Memorandum in Support of its Motion for Summary Judgment.

66074

THE UNDISPUTED FACTS -- STILL UNDISPUTED

Rule 7 of the Utah Rules of Civil Procedure mandates with respect to summary judgment motions that: "Each fact set forth in the moving party's memorandum is deemed admitted for the purpose of summary judgment unless specifically controverted by the responding party" Ut.R.Civ.P. 7 (c)(3)(A) (emphasis added.)

In its opening memorandum, PacifiCorp provided twenty-nine factual statements to which it contends no genuine issue of material fact exists, each supported by sworn affidavits or appropriate deposition or other documentary evidence. In their opposing memorandum, plaintiffs specifically did not dispute five of PacifiCorp's Undisputed Facts, i.e., paragraphs 12, 13, 14, 15, and 25. Plaintiffs also ignored three additional factual statements, thus admitting them, i.e., paragraphs 18, 27 and 28.

Additionally, while plaintiffs wrote a sometimes lengthy response to the remaining twenty-one paragraphs of Undisputed Facts, they did not "specifically controvert" any of these facts as required by Ut.R.Civ.P. 7 (c)(3)(A). Rather, their asserted "disputes" with the Undisputed Facts are really nothing more than arguments about the implication of the facts. Repetitiously telling their story with irrelevant details does not "specifically controvert" the facts or satisfy the requirements of Rule 7. *See e.g., Beutella v. A.H. Robbins Co., Inc.*, 2001 WL 35669202 (Utah Dist. Ct. Dec. 10, 2001) (holding that a repetitious argument coupled with voluminous irrelevant details does not meet the requirements of Rule 4-501 to provide a "concise statement" that specifically controverts the movant's statement of undisputed facts.)

Moreover, Rule 7 allows that a non-moving party's opposition memorandum "[m]ay contain a separate statement of additional facts that is controverted." *See* Utah R.Civ.P. 7

keep the information confidential, even without a written agreement This is not what Graeber said at all Rather, he testified that he had no memory of what happened at UAMPS and could not even confirm that UAMPS was given a copy of Volume 1 [84] Tom Florence's affidavit stating that Volume 1 was handed to him without any assurance of confidentiality remains unchallenged

The importance of this issue is illuminated by plaintiffs' own statement that "USA Power viewed the secrecy of its work as the 'lifeblood' of its business "[85] This demonstrates quite clearly that by giving Volume 1 to UAMPS without any assurance of confidentiality, plaintiffs did not take "reasonable [effort] under the circumstances to maintain its secrecy "[86] Accordingly, Volume 1 cannot, by definition, be a trade secret

CONCLUSION

For the reasons set forth in PacifiCorp's motion papers, the Motion for Summary Judgment should be granted

DATED this 26th day of July, 2007

P Bruce Badger

P Bruce Badger
FABIAN & CLENDENIN
a professional corporation
Attorneys for PacifiCorp

[84] Graeber Depo at page 339-342
[85] *See* plaintiffs' opposition memorandum at page 7
[86] Utah Code Annotated § 13 24 2(4)

COPY OF TRANSCRIPT

IN THE THIRD JUDICIAL DISTRICT COURT

OF SALT LAKE COUNTY, STATE OF UTAH

USA POWER, LLC; USA POWER PARTNERS, LLC; and SPRING CANYON ENERGY, LLC, Plaintiffs, vs. PACIFICORP, JODY L. WILLIAMS and HOLME, ROBERTS & OWEN, LLP, Defendants.	30(b)(6) Examination: **RAND THURGOOD** Civil No. 050903412 Judge Tyrone E. Medley

September 28 , 2006 * 9:30 a.m.

Location: TOMSIC & PECK
Attorneys at Law
136 East South Temple, Suite 800
Salt Lake City, Utah 84111

Reporter: LANETTE SHINDURLING, RPR, CRR
Notary Public in and for the State of Utah

in May.

A. Well, they were selected in April and they started as soon as we hired them. So I think there was probably some work done in April.

Q. Okay. Leaving them aside, had anyone on your staff done any performance calculations for a dry-cooled plant at Mona?

A. Yes.

Q. Who had done them?

A. Ian.

Q. And he had done those through a software package?

A. More than likely.

Q. You don't know?

A. Well, I don't know what he used. He had several different software packages that gave him performance for gas turbine and combined cycle. I can't speak to which ones he used.

Q. Do you know what software packages he had?

A. I don't recall their names, no.

Q. Are you familiar with, for example, Gate Cycle?

A. No.

Q. Are you familiar with GTS?

A. That one rings a bell.

Q. Do you understand what the purpose of the performance curves would be?
A. Yes.
Q. I mean, for the record, could you explain?
A. Well, you look at any of these programs, they're basically saying if you have a particular machine at a given altitude, under certain specific temperature conditions, then it will predict fairly accurately what its performance might be.
(EXHIBIT-368 MARKED.)
Q. (BY MR. PETERSEN) All right. And, Mr. Thurgood, if you can identify what's Exhibit 368.
A. It's an e-mail from Jim Lacey to myself with respect to water use at Mona Elberta dated March 4, 2003.
Q. And you understand this is showing consumptive water use at a central Utah water site; do you see that?
A. Yes.
Q. And it looks like it's done for a wet-cooled plant?
A. Yes.
Q. Do you see it talks about -- well, let's turn to page 3. Do you see the calculations here?
A. I do.

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COPY OF TRANSCRIPT

IN THE THIRD JUDICIAL DISTRICT COURT

OF SALT LAKE COUNTY, STATE OF UTAH

USA POWER, LLC; USA POWER PARTNERS, LLC; and SPRING CANYON ENERGY, LLC, Plaintiffs, vs. PACIFICORP, JODY L. WILLIAMS and HOLME, ROBERTS & OWEN, LLP, Defendants.	Deposition of: **KENNETH IAN ANDREWS** Civil No. 050903412 Judge Tyrone E. Medley

February 15, 2006 * 9:00 a.m.

Location: TOMSIC & PECK
Attorneys at Law
136 East South Temple, Suite 800
Salt Lake City, Utah 84111

Reporter: LANETTE SHINDURLING, RPR, CRR
Notary Public in and for the State of Utah

had to be produced and that it could be executed. This could not be a paper exercise.

Q. You testified before as to the air and water cooling issue. Do you remember when that was actually resolved?

A. I think in May of 2004. Pardon me. What year are we in?

Q. 2003.

A. Thank you.

Q. And what was the resolution on that?

A. We had made a -- we had attempted to purchase a large quantity of water that we thought was sufficient for a water-cooled plant and that did not prove out. As a result of that, not having sufficient water, we recognized that we were going to have to adopt air cooling.

Q. And at this time, which is to say May of 2003, did you have information back from Stone & Webster regarding air cooling?

A. We had the performance numbers of what that would be. And so then we used that as our basis for the NBA of an air-cooled plant and based the performance and the cost on an air-cooled plant.

Q. At that time, which is to say May of 2003, did you actually have the water even for an

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air-cooled plant?
A. No, I don't know.
Q. Was there a person in particular that made the decision in May of 2003 to go with an air-cooled plant?
A. Well, I'm sure there was a recommendation. I'm assuming a recommendation was made by Rand Thurgood and I believe our management approved of that recommendation.
Q. When you say your management, who is the management?
A. Well, Rand reported at that time to Barry Cunningham who reported to Judy Johansen.
Q. And were you present for any of these meetings when this decision was made?
A. I was not.
Q. Do you remember having any discussion with Mr. Thurgood about this time, which is to say May 2003, regarding this issue of air cooling versus water cooling?
A. Yes.
Q. And do you recollect the substance of those discussions?
A. That going with an air-cooled plant is not an all bad thing. That in spite of its performance

COPY OF TRANSCRIPT

IN THE THIRD JUDICIAL DISTRICT COURT
OF SALT LAKE COUNTY, STATE OF UTAH

USA POWER, LLC; USA POWER PARTNERS, LLC; and SPRING CANYON ENERGY, LLC, Plaintiffs, vs. PACIFICORP, JODY L. WILLIAMS and HOLME, ROBERTS & OWEN, LLP, Defendants.	Deposition of: **THEODORE BANASIEWICZ** VOLUME II Civil No. 050903412 Judge Tyrone E. Medley

March 7, 2006 * 10:08 a.m.

Location: SUROVELL, MARKLE, ISAACS & LEVY
Attorneys at Law
4010 University Drive, Suite 200
Fairfax, Virginia 22030

Videographer: David Voitsberger
Reporter: LANETTE SHINDURLING, RPR, CRR
Notary Public in and for the State of Utah

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A. There is.

Q. And when did that occur?

A. It occurred in a meeting on February 18th, 2003, in the Salt Lake City offices of PacifiCorp.

Q. And very generally, and we can go into this in more depth later on, what was included in Volume 3?

A. Well, a Table of Contents is included here and I'll just run down the list. It's a Strategic Power Market Assessment, the Final/Approved Air Permit. We have the Final/Approved Water Permits. We have the Final Approved Exempt Wholesale Generator Permit. There is a section about the transaction and pro forma assumptions and then there are the economic pro formas.

Q. And the economic pro formas and the transaction pro formas, how are those different?

A. There are two pro formas that were included. One is a base case pro forma through title "Base Case" and one is titled the "Expected Case Pro Forma."

Q. Okay. All right. Now, before we go into that in detail, let me ask you generally, did you have a follow-up meeting with PacifiCorp regarding the potential purchase of Spring Canyon?

From: Green, Mark [mark.green@shawgrp.com]
Sent: Sunday, June 22, 2003 1:40 PM
To: bob.vanengelenhoven@pacificorp.com
Cc: kenneth.andrews@pacificorp.com; merrill.brimhall@pacificorp.com; Gappa, Rob; Mitchell, Elmer (DEN); Galpin, Dave; Gartner, Rodney; Currant-Creek Mail
Subject: FW: Back-up Data for PAC Comparison & Vendor Info on PAC System Attached

Bob----

Attached (see E. Mitchell's email below dated 6/20/03) is our analysis of an alternate condensing scheme to compare to the larger ACC (98° F, 6-in. HgA) originally requested by PacifiCorp to maximize power output at the 1% dry bulb temperature. The alternate consists of a smaller ACC with a wet cooling tower providing additional power at dry bulb temperatures above 80° F. This alternative is more cost effective and nets additional revenue generation versus the dry cooling option currently included in the cost estimate. Another advantage is that the alternate condensing scheme generates additional revenue over the life of the project while staying within the water supply constraints on this project (net 400 ac-ft). This, of course, depends on exactly what temperature we turn on the cooling tower. Within the accuracy of this study, we can hold the current water supply limits to a net 400 ac-ft if the cooling tower is utilized above 80° F (see attached water balance). The attached performance comparison curves show that at 100° F, the alternate condensing scheme generates an additional 10 MW net versus the base ACC.

Information on GEA's PAC system is included which comprises the alternate condensing system we are evaluating. Included are examples of several installations that have utilized this hybrid condensing system. In several instances, they had to either modify their existing ACCs to the PAC design or design the PAC into their original plant design due to similar constraints regarding water availability.

We estimate that the alternate condensing scheme will cost approximately $500,000 - $1,000,000 more than what is included in the cost estimate now. This assumes that we will be able to pump from groundwater at ~890 gpm for the two month period in July and August. If this is acceptable, we will be able to avoid the costs of adding a water storage reservoir.

I hope this information will be helpful to PacifiCorp in developing an alternate that is more cost effective and yields additional power above the current design point.

Please advise if you have any questions or require additional information to evaluate this alternative

Mark E. Green, PE

Project Manager

Shaw/Stone & Webster Power Division

[illegible] Dry Creek Road

[illegible], CO 80112

[illegible]

[illegible] Cell

PAC031767

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303-741-7040 Fax

mark.green@shawgrp.com

-----Original Message-----
From: Mitchell, Elmer (DEN)
Sent: Friday, June 20, 2003 3:00 PM
To: Green, Mark
Subject: Back-up Data for PAC Comparison & Vendor Info on PAC System Attached

<<Performance Comparison for ACC-CT Option with 80-20 Thermal Duty Split (includes water balance).pdf>>
<<GEA PAC Information.pdf>>

O. Elmer Mitchell

Consultant - Mechanical Group

Stone & Webster, Inc., a Shaw Group Company

tel +1 303 741 7337 fax +1 303 741 7040

elmer.mitchell@shawgrp.com

PAC031768

6994

From: Green, Mark [mark.green@shawgrp.com]
Sent: Wednesday, June 25, 2003 7:25 AM
To: Andrews, Kenneth; Van Engelenhoven, Bob
Cc: Brimhall, Merrill; Gappa, Rob; Mitchell, Elmer (DEN); Galpin, Dave; Gartner, Rodney; Currant-Creek Mail
Subject: RE: Back-up Data for PAC Comparison & Vendor Info on PAC SystemA ttached
Ian---

See comments below to your 6/23 email.

Call me if you have any further questions.

Mark E. Green, PE
Project Manager
Shaw/Stone & Webster Power Division
9201 E. Dry Creek Road
Centennial, CO 80112
303-741-7333
303-882-0067 Cell
303-741-7040 Fax
mark.green@shawgrp.com

-----Original Message-----
From: Andrews, Kenneth [mailto:Kenneth.Andrews@pacificorp.com]
Sent: Monday, June 23, 2003 6:19 PM
To: Green, Mark; Van Engelenhoven, Bob
Cc: Brimhall, Merrill; Gappa, Rob; Mitchell, Elmer (DEN); Galpin, Dave; Gartner, Rodney; Currant-Creek Mail
Subject: RE: Back-up Data for PAC Comparison & Vendor Info on PAC SystemA ttached

Mark,

Our analysis indicates the wet side-stream CT would provide approximately 5,900 MWhs of additional on-peak generation assuming the wet CT is engaged at temperatures of 80F and above. If the total additional installed cost were $1,000,000 it would be clear we should proceed. Our threshold total capital we could prudently spend for this improvement is approximately $2.0 - $2.1 million. Before we can provide guidance on whether we should proceed or not, we need to determine:

Total all-in cost for this improvement, including cooling tower water treatment equipment, additional costs for any evaporation pond expansion required, tie-in piping, controls and controls tie-in, installation/construction costs for the wet CT, Shaw markups, PacifiCorp overheads, plus any additional water costs. One of the first issues we would like your input on is what you think the all-in costs are (except PacifiCorp overheads) and water.

The values given in my 6/22 email included everything on the EPC side including installation costs of all the items required for this option and are order of magnitude at this time (study grade). Additionally, the information forwarded in the prior email shows that there is no basis to increase the evaporation ponds since we have 20 acres now and we estimate that this is more than we need even when you factor in the cooling tower.

Our pricing does not include PacifiCorp overheads nor do they include the cost

of the water. There are a lot of variables that will determine the actual final costs and equipment sizing, but the pricing provided in the prior email is good enough to do comparative analysis of the two options.

We believe, as we stated in our 6/19 weekly conference call, that if this option appears economically viable that there is room to optimize (lower) the final costs of this type of system. One of those options is looking at spray cooling and provides other advantages to the project w/ regard to potential improved evaporation rates. These will have to be looked at in a later study but only when PacifiCorp feels that further study effort is warranted (i.e. there is an adequate payback possible for the hybrid cooling system).

-The other major issue you raised is whether or not we can pump water at the 890 GPM flow rates without a raw water storage pond/tankage. We will explore this from flow study data from the potential sellers of water. Assuming we cannot pump at this level, it would be helpful to have a rule of thumb cost for raw water storage if we are limited to a lower pumping flowrate and some raw water storage is needed.

We estimate that the order of magnitude cost to provide a 100 ac-ft storage pond is approx. $1.5 MM. Note that in the analysis provided in the 6/22 email that providing a 95 ac-ft storage pond will reduce the water pumping rate from 890 gpm to approx. 600 gpm during the July and August period. Also note that a storage pond increases the water demand by +/- 5% due to increased losses from evaporation (in the storage pond) and losses due to seepage from the pond.

This analysis presumes no increase in water consumption. Inasmuch as this still uses a wet CT, evap losses will occur from the side stream wet CT. Is there an estimate on what the additional water lost to evaporation from the CT is

These losses have been accounted for in the analysis and are included/shown on the water balances in the 6/22 email. We estimate that make up to the tower will be approximately 744 gpm during the period the tower is in operation. We are attempting to minimize the freshwater makeup to the tower by using the RO centrate (59 gpm) as part of the tower makeup. This leaves a net of approx. 658 gpm that will have to be provided from the wells.

If you or your team have any questions, please call so we can come to answer on which direction we should take on this issue.

Best Regards.

Ian

If we are unable to pump at the 890 GPM rate,

-----Original Message-----
From: Green, Mark [mailto:mark.green@shawgrp.com]
Sent: Sunday, June 22, 2003 1:40 PM
To: bob.vanengelenhoven@pacificorp.com
Cc: kenneth.andrews@pacificorp.com; merrill.brimhall@pacificorp.com; Gappa, Rob; Mitchell, Elmer (DEN); Galpin, Dave; Gartner, Rodney; Currant-Creek Mail
Subject: FW: Back-up Data for PAC Comparison & Vendor Info on PAC System Attached

PAC031770

6996

Bob----

Attached (see E. Mitchell's email below dated 6/20/03) is our analysis of an alternate condensing scheme to compare to the larger ACC (98° F, 6-in. HgA) originally requested by PacifiCorp to maximize power output at the 1% dry bulb temperature. The alternate consists of a smaller ACC with a wet cooling tower providing additional power at dry bulb temperatures above 80° F. This alternative is more cost effective and nets additional revenue generation versus the dry cooling option currently included in the cost estimate. Another advantage is that the alternate condensing scheme generates additional revenue over the life of the project while staying within the water supply constraints on this project (net 400 ac-ft). This, of course, depends on exactly what temperature we turn on the cooling tower. Within the accuracy of this study, we can hold the current water supply limits to a net 400 ac-ft if the cooling tower is utilized above 80° F (see attached water balance). The attached performance comparison curves show that at 100° F, the alternate condensing scheme generates an additional 10 MW net versus the base ACC.

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I hope this information will be helpful to PacifiCorp in developing an alternate that is more cost effective and yields additional power above the current design point.

Please advise if you have any questions or require additional information to evaluate this alternative

Mark E. Green, PE

Project Manager

Shaw/Stone & Webster Power Division

9201 E. Dry Creek Road

Centennial, CO 80112

303-741-7333

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303-741-7040 Fax

PAC031771

6997

mark.green@shawgrp.com

-----Original Message-----
From: Mitchell, Elmer (DEN)
Sent: Friday, June 20, 2003 3:00 PM
To: Green, Mark
Subject: Back-up Data for PAC Comparison & Vendor Info on PAC System Attached

<<Performance Comparison for ACC-CT Option with 80-20 Thermal Duty Split (includes water balance).pdf>> <<GEA PAC Information.pdf>>

O. Elmer Mitchell

Consultant - Mechanical Group

Stone & Webster, Inc., a Shaw Group Company

tel +1 303 741 7337 fax +1 303 741 7040

elmer.mitchell@shawgrp.com

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6999

From: Brimhall, Merrill
Sent: Friday, June 27, 2003 5:45 PM
To: Thurgood, Rand; Lacey, James; Andrews, Kenneth
Subject: FW: Water Pond Storage.xls

Jim and Elmer (at SHaw/S&W)may want to see if there is agreement on the total annual water consumption. Whether dry or hybrid.

It looks like Hybrid might be out of the picture for the full 1000 mw, but possible if we only install 500mw.

-----Original Message-----
From: Brimhall, Merrill
Sent: Friday, June 27, 2003 4:11 PM
To: Andrews, Kenneth; Lacey, James
Cc: Van Engelenhoven, Bob
Subject: Water Pond Storage.xls

Ian - see column C18 If we use Shaw's annual monthly estimate for combination wet/dry cooling water usage - column B, then set July and August to run without the minicooling tower additional use (890 goes back to 232) then we get....
233 Acre Ft for 500 mW or 466 for 1000mW.

Does this mean we need to go out and buy an additional...66 * 2 = 132 acre ft? to cover the 1000 mw.

If we decide to go 1000 mw with the mini cooler/wet-dry hybrid. Then we need...
(410+10)*2=840 acre ft.over and above the current 800 acre ft we are pursuing.

I talked to Dave Galpin about this. He will have Elmer take a look at it on Monday.

Talk among yourselves and then let Rand know.

PAC031774

07 ... 0:57

B ______ CLERK

Peggy A. Tomsic (3879)
Kristopher S Kaufman (10117)
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136 East South Temple, Suite 800
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Robert Surovell
J Chapman Petersen
Surovell, Markle, Isaacs & Levy
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Facsimile. (703) 591-9285

Attorneys for Plaintiffs
USA POWER, LLC;
USA POWER PARTNERS, LLC;
SPRING CANYON ENERGY, LLC

IN THE THIRD JUDICIAL DISTRICT COURT OF SALT LAKE COUNTY

STATE OF UTAH

USA POWER PARTNERS, LLC, USA POWER PARTNERS, LLC, and SPRING CANYON ENERGY, LLC, Plaintiffs, vs PACIFICORP, JODY L WILLIAMS and HOLME, ROBERTS & OWEN, LLP Defendants	MEMO IN SUPPORT OF USA POWER'S MOTION FOR LEAVE TO FILE SUPPLEMENTAL AFFIDAVIT OF PEGGY A TOMSIC Civil No. 050903412 Judge Tyrone E Medley

7121

ARGUMENT

The Court should grant USA Power leave to file the Supplemental Affidavit of Peggy A. Tomsic, to be added as part of the record in opposition to Defendants' motions for partial summary judgment and summary judgment. [A copy of the supplemental affidavit is attached as Exhibit A].

Utah Rule of Civil Procedure 56(e) allows the Court to "permit affidavits to be supplemented" by further affidavits. Of the hundreds of thousands of pages of documents, testimony and pleadings, including thousands of pages already filed with respect to summary judgment alone, the supplemental affidavit of Peggy A. Tomsic attaches relatively few pages of documents and testimony which inadvertently were not included as part of Plaintiffs' Memoranda or the prior Affidavits of Peggy A. Tomsic. This oversight is due to the voluminous record in this case, including the record filed by the Defendants in support of their motions for summary judgment.

Granting USA Power leave to file the Supplemental Affidavit of Peggy A. Tomsic will not unfairly prejudice Defendants. The affidavit and attached documents do not create new issues of fact or present new arguments, but merely provide additional factual support for the disputes already highlighted in the memoranda filed in opposition to Defendants' motions for summary judgment. Finally, both Defendants will have ample opportunity to address the supplemental affidavit during oral argument approximately one month from now.

CONCLUSION

For the foregoing reasons, the Court should grant USA Power's Motion for Leave to File Supplemental Affidavit of Peggy A. Tomsic.

Dated: August 28, 2007.

Peggy A. Tomsic
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136 East South Temple, Suite 800
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Telephone: (801)-532-1995

Attorneys for Plaintiffs

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Attorneys for Plaintiff USA POWER, LLC;
USA POWER PARTNERS, LLC;
SPRING CANYON, LLC

IN THE THIRD JUDICIAL DISTRICT COURT OF SALT LAKE COUNTY

STATE OF UTAH

USA POWER, LLC, USA POWER PARTNERS, LLC, and SPRING CANYON ENERGY, LLC, Plaintiff, vs. PACIFICORP, JODY L. WILLIAMS and HOLME, ROBERTS & OWEN, LLP., Defendants.	SUPPLEMENTAL AFFIDAVIT OF PEGGY A. TOMSIC Civil No. 050903412 Judge Tyrone E. Medley

7126

STATE OF UTAH)
:ss.
COUNTY OF SALT LAKE)

Peggy A. Tomsic, being first duly sworn, states as follows:

1. I am the a member of Tomsic & Peck LLC and a member in good standing of the Utah State Bar. I am one of the lawyers who represents the plaintiffs in this action.

2. Attached as Exhibit 1 is a true and correct copy of handwritten notes from Ian Andrews notebook, Bates Nos. PAC025251-25254; PAC025267; PAC025273; PAC025304-25306; PAC025309; PAC025348; PAC025398; PAC025461; PAC025543; PAC025574; PAC025624.

3. Attached as Exhibit 2 is a true and correct copy of an email from David Eskelsen to Jody L. Williams, et al., Bates Nos. HRO-PC 001223-1224.

4. Attached as Exhibit 3 is a true and correct copy of an invoice dated August 28, 2002 from Qwest for telephone numbers 970-871-6223, 970-871-6234, and 970-871-9135. This invoice was produced by plaintiffs but does not bear any Bates Numbers.

5. Attached as Exhibit 4 is a true and correct copy of excerpts from the deposition of Lois Banasiewicz.

6. Attached as Exhibit 5 is a true and correct copy of excepts from the deposition of Rand Thurgood.

7127

7. Attached as Exhibit 6 is a true and correct copy of excerpts from the deposition of Steven Vuyovich.

8. Attached as Exhibit 7 is a true and correct copy of excerpts from the deposition of David Barlow.

9. Attached as Exhibit 8 is a true and correct copy of an excerpt from the deposition of Michael Jenkins.

10. Attached as Exhibit 9 is a true and correct copy of a document which was marked as Deposition Exhibit 3.

11. Attached as Exhibit 10 is a true and correct copy of a document which was marked as Deposition Exhibit 129.

12. Attached as Exhibit 11 is a true and correct copy of a document which was marked as Deposition Exhibit 130.

13. Attached as Exhibit 12 is a true and correct copy of a document which was marked as Deposition Exhibit 131.

14. Attached as Exhibit 13 is a true and correct copy of a document which was marked as Deposition Exhibit 132.

15. Attached as Exhibit 14 is a true and correct copy of a document which was marked as Deposition Exhibit 133

16. Attached as Exhibit 15 is a true and correct copy of a document which was marked as Deposition Exhibit 254.

17. Attached as Exhibit 16 is a true and correct copy of a document which was marked as Deposition Exhibit 293.

18. Attached as Exhibit 17 is a true and correct copy of a document which was marked as Deposition Exhibit 306.

19. Attached as Exhibit 18 is a true and correct copy of a document which was marked as Deposition Exhibit 370

20. Due to the overwhelming size of the record in this case, the foregoing exhibits were inadvertently excluded from Plaintiffs' memoranda and my prior affidavits.

DATED: August 28, 2007.

Peggy A. Tomsic

SUBSCRIBED and sworn to before me this 28 day of August, 2007.

Notary Public
Residing at: Salt Lake County

Notary Public
COLLEEN PETERSON
50 South Main, Suite 1250
Salt Lake City, Utah 84144
My Commission Expires
September 26, 2008
State of Utah

CERTIFICATE OF SERVICE

I hereby certify that on the 28 day of August, 2007, a true and correct copy of SUPPLEMENTAL AFFIDAVIT OF PEGGY A. TOMSIC IN OPPOSITION TO PACIFICORP'S AND WILLIAMS/HRO'S MOTIONS RE: SUMMARY JUDGMENT was mailed, postage prepaid, to the following:

Thomas R. Karrenberg, Esq.
ANDERSON & KARRENBERG
50 West Broadway, #700
Salt Lake City, Utah 84101

P. Bruce Badger
Fabian & Clendenin
215 South State Street, 12th Floor
P. O. Box 510210
Salt Lake City, Utah 84151

Michael G. Jenkins
Assistant General Counsel
PacifiCorp
1407 West North Temple, Suite 310
Salt Lake City, Utah 84116

Colleen Peterson

7130

1-13-2003

1. One Line Diagrams for Sites
2. Transmission Line Capabilities - Sec 1-10
3. Review Cost Spreadsheet
4. Melissa Olson
5. Table of Transmission Requests. Status
6. Carbon
   A. Do Drawing Revisions
   B. Figure out Cross Wiring - Do Isolators or A New Board
   C. Print out New Point List
   D. Update Data Base
   E. Make New Table
   F. Arrange to figure out Modem, Setting Order

1-14-2003 1:00 Panda
2:00 USA Power
Brian Gross 972-980-7159
David Barlow

PANDA

Secured Acres + Met Data
- Not Huge Priority to Deal with
- Won't build in next 3-4 years
- Happy to Sell Land, Met Data, Work to Date
For Actual Verifiable $964,818 1.5 yr Data
- People have asked for Data
- Options Assignable ~~80 acres~~ ⇒? 320 acres.
Met Tower
+ Survey Work
+ Work on Air Permit
East of Mona Sub
Dual Connect to Kern + Questar

Feb 28 - $20,000 Buys another year
Apr 16 $20,000
Land price going up.

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PAC025251

7132

USA is interested in Met DATA
Alter Size of plant to get away w/o Met DATA
Met DATA Has been Audited & Qualified for State
USPD MSI & others collected DATA

Met Tower is included worth $250,000
will Put together Sum of options by ~~[illegible]~~ end of week
Knows guys in Portland
GARY BRIAN GROSS
972 980 7159 DAVID BARLOW

WATER ?

- Need Regular Audits & Buy off from State for PSD
- Buy this Documentation

- Ask

USA Power
Dave
TED BANKOWITZ
Both talked to Stacey Recently
- MSP problem costs NOT fully Allocated
- USA Power - Time in Next 60 Days
to Deal with [illegible]
Listened for Win-Win situation
Structured option agreement
- Structure
• Up Front Pmt Cash + expense
+ Air Credits
- Monthly Fee
- Up front may be better for Consultant

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PAC025252

1133

USA Power

1 — Air Credit will Fail with USA Power
2 — $8,000,000 is too high
3 — $3-4,000 is more in line
4 — Already $1,000,000 + in expenses
seemed 10% with them.
5. Just 3 guys at the company — Can't analyze option
6. Everyone wants to see us on wet days
Some Companies have hybrid Cooling Systems.
** Have we looked at GEA for G.E. — wet/dry
Replaced [illegible] cooling

If we could get 20% of wet cooling we
could get 80% of performance
GEA is Running numbers on hybrid System

Chillers not most efficient
D'Olier
William Dozier Earl
Ask Ed McAfee about Blundell
INEL green Power - experienced stable company
Idea of additional Geothermal
Should be ok to add 40 MW Blundell upgrade

Panda
Dave Barlow Met Data Meets PSD Requirement
Env. Consultant could talk w/
214-557-8830
Brian Gross could set up 352-332-6444
Travis Epes - ECT consultant to do Met Data
- Paid $36,000 for Feasibility Study Plenty of [illegible]
Said no Problems Fatal Flaw Analysis
Environmental Study

Interconnection Study

Didn't go to next step

Lost Place in Queue

~~Work~~ Not ~~Busy~~ Too Busy - ~~Available~~

Would tap into Remaining line

At Entergy - would reimburse

If we pick up project - they could renew they

- the project

2200 MW in Arkansas > Panda Projects

2200 Gila Arizona

Marketing Power on Merchant Basis

— If plant gets built will purchase IPP new plant

LADWP has surplus would support expand IPP

good citizens aside from LADWP

got lots of support politically state

Had some water options 3 could have supplied water.

will provide water info.

Site engineers

Phase I environmental studies

tested soil compaction

No Bones

No easement option

good time to buy

Dave would like to help.

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1-27-2003

- JODI Re: WATER @ RUBORTA — TALKED KAREN MATTHEWS
- Dave A / Ron Drains Relator
- CARBON DRAWINGS
- CH2M Hill DRAFT. MTG. @3:00
- ✓ Dennis Harper
- Run ... sheet.
- Air plane CELBER
- ✓ PNMR

DAVE ANDERSON — 350 @ — ORDERED 2 BOARDS @ $780 ...
Some question on how to pay for them.

1) DAVE ANDERSON 2110

CH2M Hill site Survey
Cudahy Boundary between SL & Davis County Aquifer
MOLA can't get well water from
HRO Law Firm someone recently got water rights @ MOLA

Geneva — ... + WATER FOR SALE

1-28-2003
1) JOHN KLINGER — Reviewing IRP
Do IRP About every 3rd year
No relationship to BPA + our Ability
Aluminum Base Load Going Away
Need DEFINITIONS, PPA, IGCC
Reliability of Transmission
Coal Plant is Bellingham AREA

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PAC025267

7136

Jodi Williams

Possibilities

1. DON JONES NORTH OF Nephi $4000+
2. UTAH LAKE with pipeline to pros.
3. Nephi Irrig Co. FOR THEIR WATER $4000
   buy upto 7,000 acreft
   Their total 22000 acre ft.

They have Debt to cover comes Due ~ this year

CAROL HUNTER

Give CAROL copy of site STORIES

5) JUAB TAX SUBSIDY

GARY HERBERT — UTAH COUNTY → GOVERNOR

Pres. of Counties Assoc.

PIC, CEC, CIAC

Time is of essence

EDA → Economic Development ~~AREA~~

CAROL will setup MTGS with UTAH County & JUAB County

6) TRAVIS EPPS will call back 8:00AM

2-27-03

TASKS

- ROBERTA, MONA, GADSBY TRANSMISSION
- MARK TERRY
- ✓ TRAVIS EPPS
- SEND CONTRACT
- EVAL MATRIX MONA/JUB

- DO RATINGS
- LYNN ARNOLD DID SHE GET RELEASE
- ✓ GET CLAUDIA TO GET ENGINEER TO VERIFY GENEVA WATER 541-3594 Cell - NH - MSG MSG
- ✓ AUDIT TOWER will send info
- WORK THROUGH TRAVIS let MSI know we own DATA ITS CONFIDENTIAL

1) DAVE LAMB

→ REQUISITION, SCOPE, TIME FRAME, MICHAEL KAHUT

→ UCC covers MATL not Services 54

UNDER $3000 one off off CONTRACT

WHO CAN BIND TO WATER CONTRACT.

2) Thomas Weyenberg - data Report subject to copyright law

Service Requisition Send to Michael's Attention

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Item Description - describe what needed, create option to retain rider as expert witness to appear at future date

Get Vendor #

STANDARD SHORT FORM STANDARD T&M

PAC025304

3) Bob entered requisition ECT Req # 10598271

7138

(4) Michael Kahut 6687 Ret Call

(5) Travis Epps • Hard copy reports
• Sent CD to Brian Gross
• MSI has one PM10 Sampler
Sold one kept other.
Platform still there 4'X10' 4' legs - 8' legs
• Dish may not contain PM10 disk
• over the ridge would be more of a problem
• Big Question PAVO Need offsets
Unless Minor Source 100 tons/year
Can't modify within 2 years - Circumvention of PSD
"Didn't sound like good project"
"Blew whistle on USA Power" earlier Application
Construction Permit = PSD permit

~~[illegible]~~

Tower Audit will give 9 months + 6 months further
• Talked to guy who did water for Mona - would be willing to ~~[illegible]~~ give information
Jeff Melling VP @ Ret UDAQ wanted evap ponds.
• Should be able to tell in just a couple of hours
$300.00

(6) George Wilkerson
Meteorological Solutions Inc.
Web @ MetSolutions.com
Has two PM10 samplers 7500 each New 6 Day Sched.
2257 So. 1100 East St. 203
SLC, UT 84106
Contract through us.
Will send info
Reactivate cell phone

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PAC025305

7139

ROCS 8 & 269-0294

Trace not set up for Airmod model

Needs Different Sensors Vertical [illegible]

Radiation – Program Data Collection

Tough Self [illegible]

7 Claudia @2252 –

– Then can go to State and Begin Researching Water

– Bill White has water in Utah Lake Area – Brine Water

– Ask State if water can be moved

8 Judy Call

3rd Q 5th Consecutive good results – Quarter

Oregon – Proposing 10% [illegible]

Multnomah County [illegible]

9 Mar 9 Self Assessment

RTO – [illegible]

10 ~~John [illegible]~~

N.G. Generator in Albany Area – [illegible]

Fry Substation good

Could we build line from D [illegible] to Santiam to Fry

~100 miles

plenty of existing corridors

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3-04-03

1) Jodi, Claudia, Mike & Jim Rand

RFP - 60 DAYS

Geneva 3500 acre ft @ 2300/acre ft

7000 acre ft @ 2100/acre ft

Term sheet - Jodi can look at it.

? Timing of water use - 65% cap fact - 85%

Actual Required 4600-5700 acre ft. -10% high

Jodi

- Utah Lake standard practice to annualize consumption.
- At the lake shore - minimum local interference
- No problem piping to Hale
- Talk to State Engineer about water
  Hansen Allen & Luce or Bryce Montgomery
  David Hansen.
- Probably sink 2-3 wells.
- Geneva sold 3000 acre ft to Jordan @ 2700 ft.
- Can put into non-use application
- PIC March 21st.
- Board April 17th PacifiCorp Board

** Call Ross Back 3500, 7000 = 3, 6, 6

Ask which W.R.'s they propose for

- Try to fast track on change application

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PAC025309

4-02-03

1) Bob V. Project Notebook - Saw borrowed from me + returned
2) 7:54 Am TRAVIS 352-332-0444
3) CRAIG - payment coupon, still @ 97, call Craig the Hall

TASKS

A) CARBON - Dave Nelson will call back.
B) Filing - Mona Organization
C) Call Marv re Pipeline + Warm Spgs
D) Review Mona Transmission with Don Johansen
E) MATT / Godfrey - wind data
F) Write up Mona vs Elbata
G) Find USA Power Builder
H) Questar - Do we hook them up with our ROW / Enviro Consult?
I) Do we need to set up Pre-Contract MTG?
J) Call Tom Wilson - Monitors? $7,000.00 cost $6,800
K) More Money for ECT?

TRAVIS { Met Report → }
USA Power Permit
Modeling

L) Do we have Requisition / Contract for Hansen, Allen + Luce?

Michelle
Sunday 6 Lehi All
Mon 7 St George

Apr 10 Early Morn ceremony 6:30-9:00
Apr 12 Spring mtg 6:00-8:00
Apr 13 Acapella Choir
Apr 14 Band conf.
Apr 24 } NATE
Apr 25 }

June 26, 27, 28 girls camp 23-28 Boys Camp

June 30 Pennyl?, - 9-12 river trip

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PAC025348

7142

April 30, 2003

1. TRANSMISSION STUDY LETTER
2. REVIEW L+R PREP FOR MORRIS STUDY
3. CHECK WITH BILL ON MORA INVESTMENT
4. ASK BOB ABOUT WATER STUDY
5. CARBON
6. ACCOUNTING - WORK ORDER # FOR WATER ROW.
7.

1) MARV ACKRN.

	~~Avg~~ Limit	Avg ~~Pot~~	POTENT	
DRAW 96	100,000	10,250		MOST TAKEN BY MUNICIPAL ENTITIES 4500 IRRIG, 1600 DOMESTIC
97	↓	9955		
98		8778		
99		12360	15600	

MODELING ± 200 ft. NOT HARD TO DO MODEL

2) PUMP ON NORTH SIDE OF SANTA FE
5334129

SIDE RANCH / MORRILL
HOW MUCH FOR OPTION
FIRST 3 PARCELS
{ $ 50k for 6 mo
{ + 25 k for 6 mo
incl 25,000 length } @ $2,100/acre ft.

2ND 2300/ACRE
$.100 K for
WAIT until 15th Policy MTG.

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JL JKL: ~y./

6-10-03

1) Call Terry Ray
2) Try Nephi Ingram
3) USA Power on Questar - How to pay Ray - Sell Gym
4) Ed McPheeters - Talk with Brad Williams - How will it play out

CLAUDIA 200 cumptive
150 151 consumptive

(400 + 180) 50 %

CLAUDIA - Would like to wait a couple of days till things are decided with McPheeters + Harper

5) 9:32 Michele
6) Terry Ray @ 503-813-5759
7) Get Transmission costs
8) Tickets
9) Repiscatect
10) Terry Ray - Dean Miller, Milt Patscoski, ~~Larry~~ Eldore Larry Soderquist
Send overview etc to Terry Ray
11) Harold - S.W. QTR of NW QTR Section 31 11 S 01 E.
Upper NW QTR
900 ft *
Wallace Kay - Also owns property adjacent to
12) Grant & Church 240-4074 would like mtg.
13) Marv 6331046
14) Grant Thur @ ~~9:00~~ → 10:00 here

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15) Change Request.
16) Construction Power to separately Terry Ray volunteered to help coordinate

~~MORA B~~
ENCORE
PAST PROJECTS SMALLER

SPRING CANYON
AMARILLO
DAVE ~~R~~FARBER ROSS McLAUGHLIN DAVE OLIVER
TED BANNISTER PAT GROSS PAUL DOMINGUEZ
CONCERN OVER RAND BEING IN ON ANALYSIS SINCE OUR PROJECT IS COMPETING
ADDED ENERGY QUIXX CORP INVESTOR IPP
SUBSID. OF RXCEL
NO DUCT FIRING FOR PROPOSAL
They will TAKE CARBON TAX

CHALLENGE RISK IF APPROVALS FROM EPA ETC ARE
NOT RECEIVED
WARTSILA
100 PLANTS ON LONG TERM CONTRACT
PIONEER IPP MARKET

9-22-03

1) E-MAIL
2) SUBST DESIGN
3) XFMR SPEC
4) BRIAN THOMAS — INDIFFERENT OAL
5) IAN'S WRITE UP
6) RICK SCHWEERS
7) MILEAGE
8) L & R FOR JAFFA
9) BLOWER FAN
10) JOHN PEPER 4869 GSU NO LOAD TAP CHANGER
11) DOUG E @ 8:51
12) QUESTAR
- USA POWER HAS NOT CONTACTED QUESTAR
- RECONCIL COSTS 120 DAYS AFTER end of CONST.
- PAY CAPACITY
- DON'T WANT DOUBLE DIP ON "FUEL CHARGE" 10% @ NEW LINE
- PAY THROUGH TRANSP. SERVICE AGREEMENT
- KERN IS BI-DIRECTIONAL? check for check VALVE.
- INTERIM RATES TILL EXPANSION IS AVAILABLE $.05
- SEPARATE TAP @ $1,000,000 to $2,000,000
- ENVIRO SURVEY OF BLM AND PRIVATE ROUTE

+ DAILY + MONTH LOAD PROFILE
- KERN BACK HAUL
- LOOK @ FIRM BACKHAUL RATE

NOV 2005

13) LARRY S. IMPACT STUDY by DEC 12TH

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PAC025574

7146

11-7

1) Retain communication/OJ Harmon with Folks
2) Review PAD for XFMR.
3) Put out Starter Addition cir for SW YARD
4) Schedule kick off mtg - probably w/o vendor
5) Update to IRASA on Dates
V ~~6) 5:58~~ ~~Jodi~~ Williams - withdraw offer
NREPA only applies if permit required from Feds
Hearing Dec 11th
Spring Canyon Really mad - work for competitor
7) Wayne 4328 Topo site mustreceive maps

✓ ~~8) Benefits~~
✓ ~~9) SAP Password~~ 123456

✓ ~~10) Bill Lemanski~~i / Ragnar Benson out of Pitsburgh + Chicago
Large General Contractor
11) Bruce Pitt - Doctor works with OSA Power in Mona
292-6920 in Carville
12) Ask Bruce to talk to [illegible] about Contract, Pressure etc.

13) Safety to Ladder Pool/Renir w:
14) Quest put Freeze on Scanning

15) Monday 10:30
16) Permit Public Coordinate
17) Temp water US well
18) Mark will send table, not report regarding stream affects.
Discuss @ 250 gpm
/ Rich Monday AM, Tue PM wed Any.
~~19) Flowers~~
✓ ~~20) Address~~

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PAC025624

7147

Jody L. Williams

From: Eskelsen, David [David.Eskelsen@pacificorp.com]

Sent: Wednesday, December 24, 2003 10:27 AM

To: Jody L. Williams; Tallman, Mark; Kusters, Stacey; Thurgood, Rand; Van Engelenhoven, Bob; Allen, Melanie; 'andrew.jamieson@scottishpower.com'; Bennion, Doug; Boardman, Kevin; Brockbank, Dean; Cunningham, Barry; dominic.fry@scottishpower.com; Edmonds, Bill; Furman, Donald; Griffith, Bill; Hall, Lilisa; Haller, Andrew; Hansen, Kimball; Hess, Robert; Hudgens, Terry; Hunter, Carol; Hunter, Tim; Jenkins, Michael; Johansen, Judi; Johnson, Craig; Klein, Robert; Landels, William; Larsen, Jeff; Larson, Doug; Lively, Bob; Lynch, Kevin; McMillan, Simon; Mcseveny, Colin; Mitchell, Janice; Moir, Bob; Oler Kesler, Margaret; Pommarane, Mike; Ponteri, Jay; Rhodes, Randy; Sherrard-Smith, Rachel; Stewart, John; Walje, Richard; Watters, Stan; Weaver, Rodger; Wessman, Ernie; Wright, Matthew

Subject: News reports, Currant Creek water; Mine Mapping

Not a bad story on the **Currant Creek water application** . Still, I was disappointed the Anderton did not include the factoid on the air cooled nature of the plant -- that it will use less than a tenth of the water of water cooled condenser -- I mentioned it several times ... On the **Mine mapping** story, included it mostly for context, and that Lauriski is former Energy West safety manager.

Mona power plant proposal assailed
By Dave Anderton
Deseret Morning News
Dec. 24, 2003

Electricity and water are a bad mix, according to critics of a proposed natural gas-fired power plant near Mona city.

PacifiCorp is at the center of a flurry of protests objecting to the company's plan to convert 400 acre-feet of irrigation water annually to industrial use for its $350 million Currant Creek power project.

Some fear the company's proposal to pump water from new wells will affect the town's underground water supply.

"The change applications if approved would cause a depletion of the underground water supply," said Mona Mayor Bryce Lynn in a letter to the state engineer asking that the applications be denied. "Water rights would be pumped in close proximity to Mona city's well and interfere with our well and our prior rights."

According to Jody Williams, an attorney for PacifiCorp, 400 acre-feet of water is about the same amount of water a farmer would use to grow 100 acres of alfalfa. "That's not a lot," Williams said.

The water would be used to control combustion temperature and is needed to cool the plant's turbines. Besides the city of Mona, irrigation companies and other groups are objecting to PacifiCorp's water application filed with the Utah state engineer. The Provo River Water Users Association said PacifiCorp's request "would impair the level of Utah Lake."

"Diversion of ground water as proposed by the applicant will deplete water that contributes to the volume of water in Utah Lake," said Warren Peterson, counsel for the association, in a letter to the state engineer.

Calls by the Deseret Morning News seeking comment from Peterson and Lynn were not returned Tuesday.

According to a study commissioned by PacifiCorp through Hansen, Allen and Luce Inc , a Midvale-based engineering firm, the impact on Mona's groundwater system will be minor.

"It's anticipated that we would expect the groundwater level to drop only one foot. That's very minimal," David Hansen, principal of Hansen, Allen and Luce, told the Deseret Morning News "A lot of the protest letters that have been written bring up points and issues that really don't stand when you look at the whole picture "

PacifiCorp appears confident it will receive the state engineer's approval and already has started drilling two test wells

"We are willing to take the risk on this water application simply because we have no other choice We can't meet the schedule otherwise," said Rand Thurgood, managing director of resource development for PacifiCorp, at a state engineer's office hearing on the matter earlier this month "We cannot put $350 million into the ground without water to run the plant "

In addition to its water-change application, PacifiCorp also must obtain an air quality permit and receive approval from the Utah Public Service Commission before construction of the power plant commences

The first phase of the 525-megawatt plant is expected to deliver 280 megawatts of electricity no later than June 1, 2005 By not meeting that deadline, blackouts along the Wasatch Front could result, according to the company

PacifiCorp was required to purchase roughly twice the water rights it needed - about 815 acre-feet of water tied to Currant Creek and Utah Lake - in order to convert the water to a consumptive use for its plant

Hansen said PacifiCorp's application proposes to use less water than the required water rights "There is no impact on the projected water resources of the valley," Hansen said "It's just changing its use "

Dave Eskelsen, spokesman for PacifiCorp, said the company is willing to monitor surrounding wells if water owners are worried over the impact

"We're reasonably confidant that we have put forward a water change application that's within the law and that our engineering study will certainly stand up to scrutiny," Eskelsen said

Maps of old mines to be indexed, put on computers
By Mike Gorrell
The Salt Lake Tribune
Dec 24, 2003

Two near-disasters last year -- a highly publicized incident at the Quecreek Mine in Pennsylvania, and a less well-known case at Utah's Dugout Canyon Mine -- made one thing abundantly clear The mining community needs a better system for keeping track of precisely where underground mining has occurred, especially in bygone days

To address the problem, the federal Mine Safety and Health Administration is dispensing $3 9 million in grants to 13 states to establish an electronic system of digitizing maps of abandoned coal mines The sum includes $52 000 to create digital records of Utah mining operations, particularly those that have nibbled away for a century on the seams within the Wasatch Plateau, Book Cliffs and Emery coal fields

"Missing or inaccurate mine maps, along with undetectable mine voids, present a significant threat to the safety of working miners in America today " said MSHA director Dave Lauriski, a Utah native

That became clear in July 2002 when miners at the Quecreek Mine near Somerset, Pa , broke into an abandoned mine tunnel thought to be far away based on an inaccurate old map that had filled with water over the years The underground flood that was unleashed trapped nine miners for three days before they were rescued

A month later miners in Canyon Fuel Co 's Dugout Canyon Mine encountered water seeping through the walls of a tunnel they were excavating deep beneath Carbon County

COPY OF TRANSCRIPT

IN THE THIRD JUDICIAL DISTRICT COURT

SALT LAKE COUNTY, STATE OF UTAH

USA POWER, LLC; USA POWER PARTNERS, LLC; and SPRING CANYON ENERGY, LLC,	)	Deposition of.
	)	<u>Lois Banasiewicz</u>
	)	Volume I
Plaintiffs,	)	
vs	)	Civil No. 050903412
PACIFICORP, JODY L. WILLIAMS and HOLME ROBERTS & OWEN, LLP,	)	Hon. Tyrone E. Medley
Defendants.	)	

CONTAINS CONFIDENTIAL INFORMATION PURSUANT TO CONFIDENTIALITY AGREEMENT

August 1, 2006 * 9:19 a.m.

Location: Anderson & Karrenberg
50 West Broadway, Suite 700
Salt Lake City, Utah

Reporter: Susette M. Snider, CSR, RPR, CRR
Notary Public in and for the State of Utah

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Q. (By Mr. Badger) What did you overhear?
A. I overheard a time and arrangement for that meeting to take place. I don't believe that there were any details discussed regarding our project that -- only that PacifiCorp had an interest to have a meeting with us. That's my general recollection.
Q. When did the first meeting occur?
A. That was in August 22nd.
Q. Of 2002?
A. Of 2002.
Q. Were you present?
A. I was present.
Q. Where did it take place?
A. It took place at the PacifiCorp headquarters on Multnomah, M-u-l-t --
MR. BADGER: n-o-m-a-h.
THE WITNESS: -- Multnomah, yeah, Avenue, in their offices there.
Q. (By Mr. Badger) Besides you, who was present?
A. From USA Power, Ted Banasiewicz and Dave Graeber, and from PacifiCorp, Rand Thurgood, Ian Andrews, Jim Schroeder, Stacey Kusters. And there were three other individuals that I can't recall

7166

their names.

Q. PacifiCorp people?

A. Yes.

Q. You're sure Ian Andrews was there?

A. Um-hum. Excuse me. I wanted to say yes. I was taking a drink then.

Q. Can you tell me what was discussed during that meeting?

A. We gave an overview of our Spring Canyon Energy project and gave an overview as far as what our intention was with our project at this point, and that was to find a partner that would want to participate in a 50-percent participation, investment equity, to further our development efforts.

Also, we -- we discussed our -- we discussed our -- that -- our desire to enter into a power purchase agreement to purchase up to 50 percent of the facility.

We also discussed the fact that we wanted to have a CA in place, confidentiality agreement in place, so that we could further our discussions in detail.

Q. Did you take the confidentiality agreement with you?

A. Yes, we did.

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Q. Did PacifiCorp sign it?
A. Not at this meeting, no.
Q. Was it handed to someone?
A. It was handed to Rand Thurgood.
Q. How do you know that?
A. I saw it.
Q. Who handed it to him?
A. I believe Ted Banasiewicz handed it to him. I -- Ted or Dave handed it to him, but I saw Rand take it.
Q. Did you give anyone at PacifiCorp any materials?
A. No, we did not.
Q. Did you have materials?
A. We did.
Q. What did you have?
A. We had Volume 1 of the Preliminary Offering Memorandum, the one that we showed Jody in our last meeting with her.
Q. And then when was the next meeting? Was that on September 11th?
A. Yes, the next meeting was on September the 11th.
Q. Who was present?
A. From USA Power, myself, Ted Banasiewicz

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and Dave Graeber. From PacifiCorp, Rand Thurgood, Ian Andrews and Stacey Kusters via telephone.

Q. Where did the meeting take place?

A. It took place here in Salt Lake City at the PacifiCorp offices.

Q. How long did the meeting last?

A. I think the meeting lasted approximately two hours and then followed up with a lunch meeting with Rand Thurgood immediately afterwards for another hour.

Q. Where?

A. At the New Yorker.

Q. Did Mr. Thurgood sign the confidentiality agreement that day?

A. That was the first item on the agenda, yes.

Q. Did you witness him signing it?

A. I did witness him signing it, and I also witnessed Mr. Graeber signing it.

Q. Did anyone from your group give PacifiCorp any materials?

A. Yes.

Q. What did -- what was given to them?

A. Volume 1 and Volume 2 of our Preliminary Offering Memorandum. And Ted Banasiewicz handed those to Rand Thurgood and verbally told Rand to keep this confidential, and he agreed to do that, verbally and in writing.

Q. Were they in three-ring binders?

A. They were.

Q. How thick were the binders?

A. They were pretty thick. I think the first one was probably about that thick.

Q. What would you say, two, two and a half inches?

A. Maybe a little bit bigger than that. And the second one was a little bit smaller.

Q. So they weren't the same size?

A. No, I don't believe they were.

Q. What color were they?

A. I believe they were white.

Q. Who put the --

A. Just to make something clear, we did -- we did provide blue binders as well. We did have blue binders. But as a rule, we provided white binders.

Q. You've lost me. In this meeting --

A. It was two binders, white, as far as I know at this time.

Q. Was there -- did Ted give Rand one copy of Volume 1 and one copy of Volume 2?

A. Yes.
Q. Who put those binders together? Was it you?
A. Yes, I did.
Q. Were the binders, to the best of your knowledge, ever supplemented?
A. Volume 1 and Volume 2 stood on their own. Any supplement was provided in Volume 3.
Q. Let me hand you what's previously been marked as Exhibit 10. We have that big, thick, volume of exhibits in front of you Mr. Call has been kind enough to -- thumb through that to Exhibit 10. Identify Exhibit 10. That's Volume I, isn't it?
A. This is Volume 1 of the Preliminary Offering Memorandum.
Q. And then go to Exhibit 11, if you would.
A. Um-hum.
Q. And this is Volume 2?
A. Yes, this is Volume 2 dated September '02.
Q. And it's your testimony that both of these what we've marked now as Exhibit 10 and 11 were given to Mr. Thurgood on September 11, 2002, true?
A. True.
Q. Pardon me for just a minute.
A. Sure.

connecting with -- with the Mona Substation, as I understood it.

Q. When was the next meeting at which you were in attendance with PacifiCorp?

A. That was in October 2003.

Q. Where did the meeting take place?

A. That took place also in Portland, Oregon.

Q. Who was present?

A. From USA Power, Ted Banasiewicz, Dave Graeber, myself. From Quixx Corporation, Mel Murphy, Scott Gross, Dave Olive. We had a gentleman from EIF, Energy Investors Fund, and I don't recall his name because it was the first I had met that gentleman. From PacifiCorp, Mark Tolman, Jim Schroeder, I believe her name is Diane Keloff -- I don't know the spelling of that -- and Howard Freeman via phone conference. And there was one other gentleman. I don't recall his name, but he was -- I believe he was involved with the economic pro formas.

Q. What was said during that meeting?

A. Oh, also one other individual from counsel who represented Quixx Corporation. His name was Joel Howard.

Q. What was said during that meeting?

A. What was discussed was our bid that

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PacifiCorp had shortlisted. Jim Schroeder called that meeting to have us come to PacifiCorp in Portland to further discuss and negotiate our -- our bid for the Spring Canyon Energy project.

Q. Can you tell me what was said?

A. We discussed the performance of the bid of Spring Canyon Energy. We discussed the O&M costs for running a facility with unlimited starts and stops and what that did to the economics. We discussed the time line of an EPC contractor. We talked about the time line as far as the engineering and the scope of work. PacifiCorp understood the need to release an engineer, an EPC contractor, on this job in order to meet the '05 deadline, summer of'05 deadline.

Q. How do you know what PacifiCorp understood?

A. PacifiCorp said -- Jim Schroeder stated that because of the lag of time of PacifiCorp, that in order for a facility to be online by 2005, engineering, preengineering and engineering -- we call it preliminary engineering work, needed to be accomplished in order to meet that deadline.

Jim Schroeder also stated that PacifiCorp was willing to enter into a binding MOU with a breakup fee, and that was so that a group such as ours could release our EPC contractor to start on the preliminary engineering of the Spring Canyon Energy project.

Jim Schroeder also requested from Spring Canyon Energy a time line, a scope of work that would take to accomplish the EPC, preliminary engineering, assign that for us to obtain and provide to PacifiCorp, as well as assigned the task of taking the first draft on the memorandum of understanding.

And the breakup fee was to compensate for any expenses incurred for the preliminary engineering and also to secure equipment on the market.

In addition to that, there was a discussion regarding the EIF, who they were, their credibility, what their business was. The gentleman from EIF provided in conversation the net worth of EIF and listed projects that they had accomplished and -- by providing equity.

Also it was discussed Quixx' experiences with owning and operating a gas-fired facility and maintaining it, and Quixx also provided PacifiCorp with their resumé of projects that they have online and are successfully operating and own.

We discussed the terms of a PPA. We again asked our option of extending the PPA for two

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additional five-year periods after the 20-year period was concluded. That was denied.

Scott Gross from Quixx offered to sell PacifiCorp the Spring Canyon Energy project for $1 after that 20-year term was completed.

We discussed liquidated damages. The gentleman whom -- I cannot remember his name, asked if we considered running in a simple cycle. We said no because the economics did not make sense.

And the meeting concluded by us agreeing to take on the tasks of the first draft of the memorandum of understanding -- Joel Howard was going to do that -- and the task of us releasing UE and TIC and providing us with a scope of work and time line of milestones that were needed to accomplish this.

The meeting concluded with PacifiCorp asking for that information at a certain time, and I don't remember the deadline. And we agreed that we would provide that. No further negotiations took place after that.

Q. Have you told me now everything that was discussed in that meeting?

A. As I remember it right now, yes.

Q. Following that meeting in October of 2003, what was the next meeting where you were present with

7176

PacifiCorp?

A. And that's the meeting where I am not sure if it was April or May of '04. I believe it was May of '04, and I can confirm that through our records.

Q. Who was present?

A. Present at that meeting was -- from USA Power, Dave Graeber, Ted Banasiewicz, myself. From Quixx Corporation, Scott Gross and David Olive and -- that's all I can remember at this time from Quixx.

Q. Where did the -- excuse me.

A. And then from PacifiCorp -- I'm trying to -- I'm trying to recall the PacifiCorp gentlemen, names. I'll come back to that when I recall it. They -- one gentleman was from Portland, Oregon, and he worked for Stacey Kusters. The other gentleman was in-house counsel for PacifiCorp. Mike probably knows who he is.

Q. Is it Dean Brockbank?

A. Yes, Dean Brockbank. Thank you.

Q. Where did that take place?

A. That took place in Portland, Oregon.

Q. What was the topic?

A. Topic was a power purchase agreement with Spring Canyon Energy for approximately a hundred megawatts of power, as Spring Canyon would operate as

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a cogeneration facility.

Q. Now I'd like you to walk me through your understanding of the negotiations between PacifiCorp and your group. My understanding is that those began with Mr. Thurgood's letter of February 27, 2003. Would you concur?

A. Okay. We're talking about that negotiation going back -- I just finished talking about another PPA negotiation.

Q. You did, and --

A. Okay. Let me go back to our negotiations.

Q. Should we put that letter in front of you to start your thinking?

A. Absolutely. That would be great. Thank you.

Q. Why don't we do that.

A. Thank you.

Are we finished with this phone record?

Q. I think so.

A. Okay.

Q. Let me hand you what's been marked as Exhibit 17.

A. Oh, it's heavy. Thank you.

Q. This was Mr. Thurgood's letter to Mr. Banasiewicz dated February 27, 2003, was it not?

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COPY OF TRANSCRIPT

IN THE THIRD JUDICIAL DISTRICT COURT

SALT LAKE COUNTY, STATE OF UTAH

USA POWER, LLC; USA POWER PARTNERS, LLC; and SPRING CANYON ENERGY, LLC, Plaintiffs, vs. PACIFICORP; JODY L. WILLIAMS and HOLME, ROBERTS & OWEN, LLP, Defendants.	Deposition of: DAVID J. BARLOW No. 050903412 Judge Medley

September 6, 2006 * 9:05 a.m.

Location: Fabian & Clendenin
215 South State Street, 12th Floor
Salt Lake City, Utah 84111

Reporter: Lisa D'Elia, CSR, RPR
Notary Public in and for the State of Utah

1206

PacifiCorp in terms of gauging their interest for participation, equity participation.

Q. At the time that a decision was made by Panda to sell its project assets to PacifiCorp, would it be accurate to say that Panda had been, you specifically, had been working on developing a project in Mona for Panda for somewhere around three years?

A. I started work on this early -- about, yeah, that's about right.

Q. And would it be fair to say that at the time the project assets were actually sold to PacifiCorp in February of 2003, that Panda did not have a signed agreement either to purchase or for an option to purchase water to supply the power plant down in Mona, Utah?

A. That's correct.

Q. And at the time the project was sold to PacifiCorp in February of 2003, would it be fair to say that Panda did not have an interconnect agreement with PacifiCorp relative to the Mona substation?

A. No. We just had the interconnection study done and we did not have an interconnection agreement in place.

Q. And let me ask you this. Based on your experience relative to developing power plants, are you familiar with the term the queue spot, or in the queue, in a transmission facility?

A. Yes.

Q. Is it your understanding that the first party with whom a transmission company contracts for a power plant is considered first in the queue?

A. Yes.

Q. And what is your understanding in terms of the cost of someone who comes in second in the queue, whether it would be the same or whether it would be a higher or lower cost, generally speaking?

MR. BADGER: Objection. Lacks foundation.

THE WITNESS: I don't know.

Q. (By Mr. Tomsic) You have no information on that?

A. Well, you know, I could guess at it, but I don't know definitively, you know, what that would be.

Q. In your experience, had you learned or become aware that if you were not first in the queue that the cost of interconnection could increase significantly?

MR. BADGER: Objection. Lacks foundation.

THE WITNESS: I guess that could be the

case. I'm just guessing.

Q. (By Ms. Tomsic) But you don't know; is that what you are saying?

A. I'm not an expert on that aspect of it. You know, if -- you know, when we -- with regard to this, we would have -- I would have deferred to the expertise of Pat Burnett and other people that worked on the transmission group. With regard to what Panda would typically do to develop a project is we would try to time all of the activities like an interconnection agreement, the water agreement, and the options on the land, if there was a substantial amount of money for land, which it generally wasn't, particularly in this one, to coincide with when we were going to get project financing.

Q. You knew, didn't you, that by not signing an interconnect agreement with PacifiCorp relative to the Mona substation, that another developer could come in ahead of Panda and sign an interconnection agreement and become first in queue?

A. Yes. We knew that. And with regard to anybody else at Mona, USA Power in particular, I viewed their -- the threats from them doing that as minimal in the respect that we had the MET data. I thought that was more important to us than where we were in the queue.

Q. Had you had anyone do any financial analysis of what it would cost Panda to be second in the queue?

A. No.

Q. Do you know whether or not under Utah law the type of MET data that Panda had, whether it would have been required for a 250 megawatt facility in Mona?

A. No. We focused on our plant, not other configurations. We didn't build 250 megawatt plants and so all of our studies were related to a thousand megawatt.

Q. And do you know whether or not under Utah law a developer applying, filing an NOI, could, in fact, purchase air credits to obtain a permit for a larger megawatt plant without MET data?

A. I presume that that is possible.

Q. Do you know that?

A. Not by -- not by Utah law, I don't. I may have known that at one time, but, you know, it's been a number of years since my doing this.

Q. Now, at the time Panda sold its assets to PacifiCorp in February of 2003, did you have an understanding as to whether Panda would have been required to obtain some type of a variance or a zoning change to build a power plant on its property?

A. Yes.

Q. And what was your understanding in that regard?

A. We had worked with the county as far as the zoning went and we were assured by them that that was not going to be a problem, that they were very supportive of everything that we needed to do with regard to zoning.

Q. And had Panda filed anything with the governmental agency requesting a change in the zoning at the time it sold the assets?

A. Not at that point, no.

Q. Now, at the time that PacifiCorp purchased the assets of Panda in February of 2003, had Panda filed an NOI?

A. An NOI?

Q. Notice of intent.

A. For?

Q. Its air permit.

A. For the air permit, not as yet, no. We gave -- we gathered the data. We were primed to do that.

Q. In terms of any type of an agreement with

Utah!
Where ideas connect
Department of Environmental Quality
Division of Air Quality

Michael O Leavitt
Governor
Dianne R Nielson, Ph D
Executive Director
Richard W Sprott
Director

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P O Box 144820
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www deq utah gov

FILE COPY

DAQE-AN2627001-02

November 27, 2002

Ms. Lois Banasiewicz
Principal
Spring Canyon Energy, LLC.
P. O. Box 774000-359
Steamboat Springs, Colorado 80477

Dear Ms. Banasiewicz:

Re: Approval Order: Power Generating Facility With One Natural Gas Fired Combined Cycle Turbine Generator Set With Duct Burner, Juab County – CDS SM; ATT; NSPS, HAPs
Project Code: N2627001-02

The attached document is the Approval Order for the above-referenced project.

Future correspondence on this Approval Order should include the engineer's name as well as the DAQE number as shown on the upper right-hand corner of this letter. Please direct any technical questions you may have on this project to Ms. Milka M Radulovic. She may be reached at (801) 536-4232.

Sincerely,

Richard W Sprott, Executive Secretary
Utah Air Quality Board

RWS.RR MR re

cc: Central Utah Public Health Department
Mike Owens, EPA Region VIII

EXHIBIT
168
T. Banasiewicz

UDAQ0001 1345

STATE OF UTAH

Department of Environmental Quality

Division of Air Quality

APPROVAL ORDER: POWER GENERATING FACILITY WITH ONE NATURAL GAS FIRED COMBINED CYCLE TURBINE GENERATOR SET WITH DUCT BURNER

Prepared By: **Milka M. Radulovic, Engineer**
(801) 536-4232
Email:milkar@utah.gov

APPROVAL ORDER NUMBER

DAQE-AN2627001-02

Date: November 27, 2002

Spring Canyon Energy, LLC.

Source Contact
Lois Banasiewicz
(970) 871-6223

Richard W. Sprott
Executive Secretary
Utah Air Quality Board

Abstract

Spring Canyon Energy, LLC (SCE) is proposing to construct, own, and operate a new power generating facility in the Juab Valley, Juab County, just west of the Mona Reservoir. The facility will consist of one natural gas turbine generator set in a combined cycle configuration [with one heat recovery steam generator (HRSG) and one steam turbine-generator]. In addition, there will be one diesel fired emergency generator, one diesel-fired emergency fire pump, small diesel fuel storage tanks, an air- cooled condenser (to condense spent steam back into water for recycling to the HRSG), and aqueous ammonia storage and handling equipment. The HRSG duct burners will be fired with natural gas to augment waste heat from the gas turbine exhaust. The power facility will operate with a combined net maximum generating capacity of about 280 MW at 0^0F. It is anticipated that the gas turbine will be purchased from General Electric with Dry Lo-NO_x combustion system. NO_x emissions from the gas turbine will be controlled to 2 ppmvd at 15% O_2 reference (by selective catalytic reduction system), CO to 4 ppmvd at 15% O_2 reference (9 ppmvd with duct firing), and ammonia slippage to 10 ppm. The turbine will not be designed to operate in a simple-cycle mode (i.e., bypassing the HRSG unit). Raw materials used at the Spring Canyon plant in addition to natural gas and air, are water (to generate the steam) and ammonia for the selective catalytic (NO_x) reduction process. Use of the dry type air-cooled condenser greatly reduces the plant's water usage.

Juab County is an attainment area of the National Ambient Air Quality Standards (NAAQS) for all pollutants.

New Source Performance Standards (NSPS) 40 CFR 60, Subpart GG (Standards of Performance for Stationary Gas Turbines) applies to the proposed turbine. NSPS 40 CFR 60, Subpart Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978) applies to the duct burners.

Estimated annual emissions from the entire facility, in tons per year, will be as follows: 66,4 of NO_x, 97.5 of CO, 5.3 of SO_2, 70.9 of PM_{10}, 67.12 of VOC, and 5.7 tons of hazardous air pollutants (mainly formaldehyde).

Since the emissions have increased above modeling threshold levels for the NO_x, CO, PM_{10}, and formaldehyde, an air quality modeling assessment consistent with UAC R307-410-2 was performed. The US EPA and the State accepted Industrial Source Complex Short Term - Version 3 (ISCST3) model was used by the Applicant to predict air pollutant concentrations under a simple/complex terrain/wake effect situation. The modeling analysis indicated, and the State verified, that there would be no violations of NAAQS and Prevention of Significant Deterioration increments consumption for the proposed project.

The project has been evaluated and found to be consistent with the requirements of the Utah Administrative Code Rule 307 (UAC R307). A public comment period was held in accordance with UAC R307-401-4 and comments were received. The comments were evaluated and no comment was found to be adverse to the proposed AO. This air quality Approval Order (AO) authorizes the project with the following conditions, and failure to comply with any of the conditions may constitute a violation of this order.

al Conditions:

1. This Approval Order (AO) applies to the following company:

   Corporate Office Location
   USA Power Partners, LLC
   Spring Canyon Energy, LLC
   PO Box 774000-359
   Steamboat Springs, Colorado 80477
   Phone Number (970) 871-6223
   Fax Number (970) 871-6234

   The equipment listed in this AO shall be operated at the following location:

   From Salt Lake City take I-15 south approximately 77 miles to Hwy 54. Take exit and proceed west through Mona. Go ½ mile north on Goshen Canyon Road; Plant site is ½ mile to the west.
   Juab County

   Universal Transverse Mercator (UTM) Coordinate System: UTM Datum NAD27
   4,410.042 kilometers Northing, 422.81 kilometers Easting, Zone 12

2. All definitions, terms, abbreviations, and references used in this AO conform to those used in the Utah Administrative Code (UAC) Rule 307 (R307) and Title 40 of the Code of Federal Regulations (40 CFR). Unless noted otherwise, references cited in these AO conditions refer to those rules.

3. The limits set forth in this AO shall not be exceeded without prior approval in accordance with R307-401.

4. Modifications to the equipment or processes approved by this AO that could affect the emissions covered by this AO must be reviewed and approved in accordance with R307-401-1.

5. All records referenced in this AO or in applicable NSPS standards, which are required to be kept by the owner/operator, shall be made available to the Executive Secretary or Executive Secretary's representative upon request, and the records shall include the two-year period prior to the date of the request. Records shall be kept for the following minimum periods:

A.	Emission inventories	Five years from the due date of each emission statement or until the next inventory is due, whichever is longer.
B	All other records	Two years

6. Spring Canyon Energy, LLC shall install and operate one natural gas fueled combined cycle turbine generator set with duct burner and ambient air inlet chiller with maximum combined rating of approximately 280 MW, one diesel fired emergency generator rated at 700 bhp, one diesel fired fire pump rated at 250 bhp, and miscellaneous small diesel

fuel storage tanks (each with storage capacity of less that 10,000 gallons) at the Spring Canyon Energy power generating facility in accordance with the terms and conditions of this AO, which was written pursuant to Spring Canyon Energy, LLC's Notice of Intent submitted to the Division of Air Quality (DAQ) on August 13, 2002 and additional information submitted to the DAQ on August 15, 2002, August 29, 2002, September 18, 2002, September 26, 2002, and October 10, 2002.

7. The approved installations shall consist of the following equipment or equivalent*:

A. One (1) General Electric Frame 7-FA (PG7241FA)* gas turbine, with one (1) HRSG, and one (1) steam turbine generator set.

The gas turbine is provided with ambient inlet air chiller coils. The Heat Recovery Steam Generator (HRSG) is equipped with a Selective Catalytic Reduction System for abatement of NO_x emissions from the Duct Burner and the Gas Turbine. Continuous Emission Monitoring System (CEMS) for the HRSG stack is provided for monitoring emissions from the gas turbine and duct burners The power generating facility has the following characteristics:

Maximum plant site rated output at 100% Load, 0^0F, 12.19 psia and 25% relative humidity:	280 MW
Heat input at the baseload, ISO (59^0F, site elevation):	1,472.9 x Btu/hr (HHV)***
Maximum gas turbine firing rate:	1,621.5 x 10^6 Btu/scf (HHV)

B. One (1) Coen Power Plus* duct burner state of the art, low emission technology Coen Power Plus* (subject to 40 CFR 60, Subpart Da)
Maximum firing rate: 520 x 10^6 Btu/hr (HHV)

C. One (1) Diesel Fired Emergency Generator rated at 700 bhp

D. One (1) Diesel Fired Emergency Fire Pump rated at 250 bhp

E. Miscellaneous diesel fuel storage tanks, each individual tank storage capacity is less than 10,000 gallons

F. One (1) Dry type air-cooled condenser.**

* Equivalency shall be determined by the Executive Secretary.

** This equipment is listed for informational purposes only. There are no emissions from this equipment.

***Fuel Higher Heating Value

8. Spring Canyon Energy, LLC shall notify the Executive Secretary in writing when the installation of the equipment listed in Condition #7 has been completed and is operational, as an initial compliance inspection is required. To insure proper credit when notifying the Executive Secretary, send your correspondence to the Executive Secretary, attn: Compliance Section.

If construction and/or installation have not been completed within eighteen months from the date of this AO, the Executive Secretary shall be notified in writing on the status of the construction and/or installation. At that time, the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation and may revoke the AO in accordance with R307-401-11.

Limitations

9. Visible emissions from the following emission points shall not exceed the following values:

A. Natural gas combustion exhaust stacks - 10% opacity
B. All other points - 20% opacity

Opacity observations of emissions from stationary sources shall be conducted according to 40 CFR 60, Appendix A, Method 9.

10. The following limits shall apply:

A. Gas Turbine, Stack Height - no less than 295.27 feet (90 meters) as measured from the ground
B. Gas Turbine, Stack Exit Diameter - not greater than 17 feet

11. Combined source wide CO emissions shall be no greater than 97.5 tons per rolling 12-month period.

Compliance to the above emission limitation shall be determined as follows:

CO from the gas turbine and the duct burner shall be obtained from CEMS recorded data (conversion from ppmvd into pounds shall be done using the procedure in the EPA reference Method 19 or other procedure approved by the Executive Secretary).
CO from the emergency generators shall be obtained by multiplying the engine rating, recorded hours of operation and emission factors from the Vendor data if available or EPA' s Compilation of Air Pollutant Emission Factors, AP-42

To determine compliance with a rolling 12-month total the owner/operator shall calculate a new 12-month total by the twentieth day of each month using data from the previous 12 months. Records of hours of operation and emissions rates shall be kept for all periods when the plant is in operation. For emergency generator and the emergency fire pump hours of operation shall be determined by supervisor monitoring and maintaining of an operations log. The records of consumption/production shall be kept on a daily basis.

12. Combined emission rate of PM_{10}+ NO_x + SO_2 shall not be greater than of 780.72 lb per any rolling 24-hour average at the stack exhaust (turbine and the duct burner)
Compliance to the above emission limitation shall be determined as follows:

NO_x from the gas turbine and the duct burner shall be obtained from CEMS recorded data (conversion from ppmvd into pounds shall be done using the procedure in EPA reference Method 19 or other procedure approved by the Executive Secretary).

PM_{10} from the gas turbine and the duct burner shall be from the latest emission test recorded data.
SO_2 from the gas turbine and the duct burner shall be from the latest emission test or if testing is not required by the other alternative method as approved by the Executive Secretary or Administrator.

To determine compliance with rolling 24-hour total the owner/operator shall calculate average hourly rate and sum them over 24-hour period. New 24-hour total shall be calculated by the noon of the next day. Records of hours of operation and emissions rates shall be kept for all periods when the plant is in operation.

13. Emergency generators shall be used for electricity producing operation only during the periods when electric power from the public utilities is interrupted, or for regular maintenance of the generators. Records documenting generator usage and fire pump usage shall be kept in a log and they shall show the date the generator was used, the duration in hours of the generator usage, and the reason for each generator usage.

Fuels

14. The owner/operator shall use only natural gas, as fuel in the gas turbine and duct burner; fuel oil #2 or better in the emergency generator and the fire pump.

15. The sulfur content of any fuel oil or diesel burned shall not exceed:

0.5 percent by weight for diesel fuels

The sulfur content shall be determined by ASTM Method D-4294-89 or approved equivalent. Certification of other fuels shall be either by USA Power, LLC's own testing or test reports from the fuel marketer

Federal Limitations and Requirements

16. In addition to the requirements of this AO, all applicable provisions of 40 CFR 60, New Source Performance Standards (NSPS) Subpart A, 40 CFR 60.1 to 60.18, Subpart GG, 40 CFR 60.330 to 60.334 (Standards of Performance for Stationary Gas Turbines) and Subpart Da, 40 CFR 60.40a to 60.49a (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978) apply to this installation.

17. In addition to the requirements of this AO, all applicable provisions of 40 CFR Part 72, 73, 75, 76, 77, and 78 Federal regulations for the Acid Rain Program under Clean Air Act Title IV apply to this installation.

Limitations and Tests Procedures

18. Emissions to the atmosphere from the indicated emission points shall not exceed the following rates and concentrations:

Source: Turbine GE Frame 7-FA (PG7241FA)) and Duct Burner Exhaust Stack

Pollutant	ppmvd* (15% O_2 dry) (30-day rolling average)	ppmvd** (15% O_2 dry) (30-day rolling average)	ppmvd (15% O_2 dry)
NO_x	2	2	***
CO	4	9	NA

*Total emissions concentration from the gas turbine under steady state operation not including startups and shutdowns
**Combined emissions concentration from the gas turbine and the duct burner under steady state operation not including startups and shutdowns
*** Emissions from the gas turbine (in accordance with 40 CFR 60 Subpart GG requirements)

19. Emissions testing, and compliance monitoring to the atmosphere from the duct burner shall be performed in accordance with all applicable provisions of 40 CFR 60, New Source Performance Standards (NSPS) Subpart A and Subpart Da, 40 CFR 60.40a to 60.49a (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978) apply to this installation.

20. Stack testing to show compliance with the emission limitations stated in the above condition shall be performed as specified below

A.

Emissions Point	Pollutant	Testing Status	Test Frequency
Gas turbine only	NO_x	*, **	CEMs
	CO	*	CEMs
Gas turbine & duct burner	NO_x	*	CEMs
	CO	*	CEMs
Gas turbine	PM_{10}	***	NA
Gas turbine & duct burner	PM_{10}	****	NA
Duct Burner	*****		

*Initial compliance shall be demonstrated with Relative Accuracy Testing Audit.
**Initial compliance testing for NO_x for the gas turbine shall be performed in accordance with the 40 CFR 60 Subpart GG.
***, ****Initial test to establish emission rate value for the calculations in the Condition #12
***** Initial compliance testing for the Duct Burner shall be performed in accordance with the 40 CFR 60 Subpart Da.

Initial compliance testing shall be performed within 60 days after achieving the maximum production rate at which the affected facility will be operated and in no case later than 180 days after the start up of a new emission source.

B. Notification

The Executive Secretary shall be notified at least 30 days prior to conducting any required emission testing. A source test protocol shall be submitted to DAQ when the testing notification is submitted to the Executive Secretary.

The source test protocol shall be approved by the Executive Secretary prior to performing the test(s). The source test protocol shall outline the proposed test methodologies, stack to be tested, procedures to be used. A pretest conference shall be held, if directed by the Executive Secretary.

C. Sample Location

The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other methods as approved by the Executive Secretary. An Occupational Safety and Health Administration (OSHA) or Mine Safety and Health Administration (MSHA) approved access shall be provided to the test location.

D. Volumetric Flow Rate

40 CFR 60, Appendix A, Method 2 or other testing methods approved by the Executive Secretary.

E. PM_{10}

For stacks in which no liquid drops are present, the following methods shall be used: 40 CFR 51, Appendix M, Methods 201, 201a, 202 or other testing methods approved by the Executive Secretary. The back half condensibles shall also be tested using the method specified by the Executive Secretary. All particulate captured shall be considered PM_{10}.

For stacks in which liquid drops are present, methods to eliminate the liquid drops should be explored. If no reasonable method to eliminate the drops exists, then the following methods shall be used: 40 CFR 60, Appendix A, Method 5, 5a, 5d, or 5e as appropriate, or other testing methods approved by the Executive Secretary. The back half condensibles shall also be tested using the method specified by the Executive Secretary. The portion of the front half of the catch considered PM_{10} shall be based on information in Appendix B of the fifth edition of the EPA document, AP-42, or other data acceptable to the Executive Secretary.

The back half condensibles shall not be used for compliance demonstration but shall be used for inventory purposes.

F. Calculations

To determine mass emission rates (lb/hr, etc) the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors determined by the Executive Secretary, to give the results in the specified units of the emission limitation.

G. New Source Operation

For a new source/emission point, the production rate during all compliance testing shall be no less than 90% of the production rate listed in this AO. If the maximum AO allowable production rate has not been achieved at the time of the test, the following procedure shall be followed:

1. Testing shall be at no less than 90% of the production rate achieved to date.

2. If the test is passed, the new maximum allowable production rate shall be 110% of the tested achieved rate, but not more than the maximum allowable production rate. This new allowable maximum production rate shall remain in effect until successfully tested at a higher rate.

3. The owner/operator shall request a higher production rate when necessary. Testing at no less than 90% of the higher rate shall be conducted. A new maximum production rate (110% of the new rate) will then be allowed if the test is successful. This process may be repeated until the maximum AO production rate is achieved.

H. Existing Source Operation

For an existing source/emission point, the production rate during all compliance testing shall be no less than 90% of the maximum production achieved in the previous three (3) years.

Monitoring - Continuous Emissions Monitoring

21. The owner/operator shall install, calibrate, maintain, and operate a continuous monitoring system for measuring nitrogen oxides, oxygen and carbon monoxide emissions discharged to the atmosphere from each turbine stack and record the output of the system. The monitoring system shall be used for measuring and determining compliance. The continuous monitoring system shall comply with applicable provisions of UAC, R307-170 and applicable Federal regulations for the Acid Rain Program under Clean Air Act Title IV.

22. Spring Canyon Energy, LLC shall submit for review and Executive Secretary approval CEMs monitoring plan 45 days before the turbine become operational. The plan shall address the number of monitors to be used, the method of measuring the rate in tons per hour, and the method of calculating emissions during the CEMs breakdowns.

Records & Miscellaneous

23. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any equipment approved under this Approval Order including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Executive Secretary which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. All maintenance performed on equipment authorized by this AO shall be recorded.

24. The owner/operator shall comply with R307-150 Series. Inventories, Testing and Monitoring.

25. The owner/operator shall comply with R307-107. General Requirements: Unavoidable Breakdowns.

The Executive Secretary shall be notified in writing if the company is sold or changes its name.

Under R307-150-1, the Executive Secretary may require a source to submit an emission inventory for any full or partial year on reasonable notice.

This AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including R307.

A copy of the rules, regulations and/or attachments addressed in this AO may be obtained by contacting the Division of Air Quality. The Utah Administrative Code R307 rules used by DAQ, the Notice of Intent (NOI) guide, and other air quality documents and forms may also be obtained on the Internet at the following web site: http://www.deq.state.ut.us/eqair/aq_home.htm

The annual emission estimations below include point source and do not include fugitive emissions, fugitive dust, road dust, tail pipe emissions, etc. These emissions are for the purpose of determining the applicability of Prevention of Significant Deterioration, non-attainment area, maintenance area, and Title V source requirements of the R307. They are not to be used for determining compliance.

The Potential To Emit (PTE) emissions for this source (the entire plant, or specify what portion) are currently calculated at the following values:

	Pollutant	Tons/yr
A.	PM_{10}	70.9
B.	SO_2	5.3
C.	NO_x	66.4
D.	CO	97.5
E.	VOC	67.12

HAPs

Acetaldehyde	0.015
Acrolein	0.015
1,3 Butadiene	0.017
Benzene	0.17
Ethylbenzene	1.35
Formaldehyde	1.51
Naphthalene	0.01
PAH	0.002
Propylene Oxide	1.20
Toluene	1.12
Xylenes	0.26
Totals	5.7

Approved By:

RW Sprott

Richard W. Sprott, Executive Secretary
Utah Air Quality Board

FILED DISTRICT COURT
Third Judicial District

FEB 22 2008

SALT LAKE COUNTY

By ______ Deputy Clerk

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IN THE THIRD JUDICIAL DISTRICT COURT OF SALT LAKE COUNTY

STATE OF UTAH

205

USA POWER, LLC, USA POWER PARTNERS, LLC, and SPRING CANYON ENERGY, LLC, Plaintiffs and Appellants, vs. PACIFICORP, JODY L. WILLIAMS and HOLME, ROBERTS & OWEN, LLP, Defendants and Appellees.	**JOINT NOTICE OF APPEAL** Civil No. 050903412 Judge Tyrone E. Medley

9167

Notice is hereby given that Plaintiffs USA Power, LLC, USA Power Partners, LLC, and Spring Canyon Energy, LLC jointly appeal to the Utah Supreme Court the final orders entered in the Third Judicial District Court, Judge Tyrone E Medley The appeal is from the entire judgment, which became final for purposes of appeal no sooner than January 25, 2008, together with all intermediate orders and events, including, but not limited to, the following the district court's ruling, entered October 15, 2007, the district court's Order, entered October 24, 2007, and the district court's Order, entered October 25, 2007

DATED February 22, 2008

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8148

Tab 3

0500-0M7-2

IN THE THIRD JUDICIAL DISTRICT COURT

IN AND FOR SALT LAKE COUNTY, STATE OF UTAH

USA POWER, LLC,	:	Case No. 050903412 MP
	:	
Plaintiff,	:	Appellate Case No. 20080176-SC
	:	
v	:	Volume I of II
	:	
JODY L. WILLIAMS, et al.,	:	
	:	
Defendant.	:	With Keyword Index

MOTION HEARING ON SEPTEMBER 24 & OCTOBER 2, 2007

BEFORE

THE HONORABLE TYRONE E. MEDLEY

FILED DISTRICT COURT
Third Judicial District

APR 24 2008

SALT LAKE COUNTY

By [signature]
Deputy Clerk

CARLOLYN ERICKSON, CSR
CERTIFIED COURT TRANSCRIBER
1775 East Ellen Way
Sandy, Utah 84092
801-523-1186

ORIGINAL

8167

THE COURT: I don't, not at this point.

Ms. Tomsic?

MS. TOMSIC: Your Honor, while my media is warming up, I want to start out - and I think it is very important, Your Honor, to keep something in mind here with all due respect to Mr. Karrenberg, this is a Motion for Summary Judgment and the real issue before this Court is whether the plaintiffs have presented evidence from which a jury could find that, in fact, Ms. Williams had confidential information she gained through her representation and from which a jury could find that Mr. Williams either used or disclosed confidential information without USA Power's consent. That's the issue before the Court.

And Your Honor, I want to start with the issue of whether she had confidential information and the reason I want to do that, while Mr. Karrenberg didn't specifically address that in his motion, is I think the fact that Holme Roberts and Ms. Williams have moved for summary judgment on that ground that Ms. Williams, who, there is evidence in this record from which a jury could find that she represented USA Power for over two and a half years and did so with regard to their power plant development in Northern Utah, Spring Canyon, did not, during that two and a half years and $100,000 acquire any confidential information. I think it's important because it shows you the tone and the characterization of this record of having no evidence. And again, they're claiming no evidence, Your Honor, and it is not our burden as plaintiffs to come in and disprove every defense that Holme Roberts and Ms. Williams present. The question is - and I don't want to minimize the record we've put in because the record is substantial as Your Honor is aware of, unfortunately from having to read it, whether there is a fact, a piece of testimony or a document or an inference from a document from which a jury could find one, that Ms. Williams - and if you don't mind Your Honor, just to shortcut this I'm going to refer to Ms. Williams and Holme Roberts as Ms. Williams.

THE COURT: That's fine.

MS. TOMSIC: Whether they had confidential information and whether there is evidence presented from which a jury could find that Ms. Williams either used it herself in representing Pacific Corp or disclosed that information, Mr. Karrenberg's entire argument is predicated on his position that to demonstrate a breach of confidentiality claim, the only basis for doing it is to show the actual imparting of confidential information and that's not the law.

The question is, did Ms. Williams use information she had during the course of - that she acquired during the course of representation without my client's consent or, or/and did she disclose it to Pacific Corp? It's a two-part question, Your Honor, and second, when I get to the issue of what is the law in Utah with regard to proving disclosure? Mr. Karrenberg again, with all due respect, misstates the Kilpatrick case and I know that unfortunately because I was there trying it for three months and I want to address that when I get there.

But the first thing I want to do, Your Honor, is as you know, their two grounds as I said are there's no evidence that she obtained information or that she communicated or used it. I mean in their motion at least they acknowledge it's a two-part test. Well, Your Honor, there's no question that as a fiduciary, attorneys have a legal duty to preserve the client's confidences and to disclose any material matters bearing upon the representation of the client. What is important before you even begin to look at the evidence presented both by the plaintiffs and the defendants on this motion is what the heck is confidential information and in their moving papers and their memorandum, you will notice that Ms. Williams' lawyers have narrowed the scope of confidential information to what was actually said to Ms. Williams. Well, even under that standard we could demonstrate an issue of fact but the point is, that is not what confidential information is for purposes of the attorney/client relationship and breach of the fiduciary duty.

Confidential information extends not only to matters communicated in confidence by the client but also to all information relating to the representation, whatever its source. That's what we're talking about here. And, Your Honor, confidential information just relying on the sources, legal sources that define what constitutes confidential information saying it includes all information whether in oral, documentary, electronic or other forms; information gathered from any source including sources not protected by the attorney/client privilege; work product that the lawyer develops in representing the client whether or not the information is immune from discovery; information a lawyer learns personally or through an agent. Judge, that's what we're talking about here.

Now let's look in terms of that definition, have the plaintiffs presented evidence from which a jury could find that Ms. Williams had confidential information? Your Honor, there is a dispute but there is evidence as to the scope of Ms. Williams' representation, and it's important here because there is a clear record in this case that Ms. Williams represented USA Power with regard to its development of a power plant in Mona, Utah, the Spring Canyon plant. It was a broad, enduring representation that started before Mona was selected and went all the way through - and you've seen the bills - it went through until September 2003 and according to her own information sheet, her representation was with regard to a power plant and the Retainer Agreement itself demonstrates the breadth of her representation. She agreed to represent them on advising about business strategies, advising about transaction structures, negotiating and preparing agreements, drafting filings and pleadings, researching legal issues and relevant facts, preparing for and participating in hearings and conferences and a variety of other matters. There is no limitation in that Retainer Agreement with regard to the services she would provide. And that's important because not only did she agree she was their lawyer on the power plant but the record of what she actually did demonstrates the scope of that representation as was noted by our ethics expert, John Morris, and all you have to do is just pull out some of her bills. This is one that demonstrates that she actually created Spring Canyon, the entity that was to ultimately sell most of the assets and would have been the entity that would have been awarded the RFP.

Just looking at a few of her other bills. She was involved - let me go back there because I think it's important. You can see the breadth of it, Endangered Species Act, Conference on Nephi Project, meeting with Nephi and USA Power Team, zoning application, marketing book, marketing letter, air credits. I mean, her representation was not limited. She obtained information regarding annexation of property in Mona, Utah because obviously she worked on it. She obtained information regarding the option to purchase real property, organizing and forming Spring Canyon, obtaining Conditional Use Permit Juab, County; water rights issues, business strategy, structures, selecting Mona as the development site, Endangered Species Act issues, real estate purchases, air permits, transmission issues, actions taken by USA Power's competitor, Panda, and public relations.

Your Honor, it was broad representation and as Mr. Banashevits testified in his deposition, the members of that development team, that was the USA Power Team, always included the three members of USA Power which would be Mrs. Banashevits, Mr. Graber and Mr. Banashevits, membership always included Ms. Williams. Those are factual records, Your Honor. Mr. Karrenberg may disagree and want to convince the jury to the contrary, but we have evidence of that.

Mr. Banashevits also testified when he was asked, "And how often would you have these development meetings?

"They varied throughout the development but generally multiple times per month and if they were not conducted by an in-person meeting, they would be conducted by a telephone conference."

His clear testimony, they met regularly, she as on the team and what did they discuss? They had these meeting and Mr. Banashevits testified to discuss all the issues associated with the project that were then current and to determine how we would move on to the next step with each issue. As he said, Your Honor, I think this sums it up, "We did not make a move in Utah without asking Ms. Williams for her opinion on any issue and Ms. Williams gave her opinion on those issues."

Now the question on summary judgment Judge, just looking at the issue of did she have confidential information is have we presented one inference, one document or sworn testimony suggesting Williams, HRO received information relating to the representation of USA Power whatever its source. There is no question we have met that burden.

Now, Mr. Karrenberg argues that it's undisputed that the information that plaintiffs now claim is confidential, clearly was not. Plaintiffs have not shown that the unspecified information Williams supposedly obtained was not generally known to the public. There's a problem with that, Your Honor. That's their defense, it's not us putting on the confidential information and that's clear from Utah cases that we do not have to disprove their factual defenses but more importantly, they get it wrong in terms of what is generally known information and whether or not we have presented evidence to go to a jury, even if we had disputed it as to whether it was generally known and the question is whether - first of all it depends on all the circumstance relevant in obtaining the information. You've got to look at everything to determine whether or not it was disclosed.

But more important, the definition of whether or not it is generally available or public information - and this is right out of the Restatement of Law Governing Lawyers which is one of the foremost authorities in this area, Your Honor, "Information is not generally known when a person interested in knowing the information could obtain it only by means of special knowledge or substantial difficulty or expense." That's the standard, Your Honor. And the record in this case would permit a jury to find that in fact it took substantial expense for Ms. Williams to acquire this information. All we have to do is look at some of her bills. Look at what she was charging USA Power to obtain this information and it totals up to almost $100,000, Your Honor.

And in addition our expert in reviewing this and in reviewing all the time of actual development, testified or had the opinion that it took substantial time and an estimated $3 million to develop the Spring Canyon project. Indeed Mr. Banashevits testified that Mr. Thurgood, the Pacific Corp employee with whom he had all of his dealings, admitted that it took substantial time and money to get there and this is Mr. Banashevits' deposition. He testified, "Thurgood felt that we have attained a competitive advantage that would take him two to three years to duplicate and several million dollars." Those are his words in that meeting.

So, not only have we demonstrated that there was a significant amount of time and money but according to Pacific Corp's own witness, they admit that it's not generally available information. But not only that - so the point I'm at, Your Honor, is that they haven't even established that it's undisputed, uncontroverted; that it's generally available information. Even if we had to meet that burden they haven't demonstrated that the information that Ms. Williams had would meet that definition.

Second, when USA - or excuse me, when Williams and Holme Roberts asserted it's undisputed - and again remember they're saying it's undisputed that USA Power's air permit application and water application made everything Williams learned public knowledge. Again, that's their defense and they haven't established it. It's literally impossible.

The air permit was filed on August 16 and at the very latest in 2002. According to Ms. Williams, the water change application was filed in September of 2002. Well, let's look at the dates of these bills and I'm just picking a couple. This is after we supposedly revealed everything in our air permit. This is after we supposedly revealed everything. All you have to do is just go through these bills and you will see that it's literally impossible that those permits disclosed everything that she knew that was confidential information. And what isn't included within those that is confidential that Ms. Williams had is the negotiating history with potential water rights sellers in Juab County including the level of interest, price levels and psychological barriers. The public relation history with local officials in Juab County necessary to garner public support for the project, the negotiating of procedural history to have real property in Juab County rezoned. And it goes on and on and on and on, Your Honor. I'm just going to skip over these. There's plenty of evidence in this record.

The fact that we shared our confidential information with Pacific Corp subject to a strict Confidentiality Agreement doesn't embrace the confidential nature of the information Ms. Williams had and let me tell you why. First of all, when you have a situation where you have a lawyer representing you and she has got confidential information and you take some of that information and disclose it to a party pursuant to a Confidentiality Agreement that requires them to maintain the confidentiality, it does not mean that your lawyer can then go out and disclose and use the information. That would be absurd and there's not a single case that Mr. Karrenberg has cited for that proposition.

But more importantly, the record demonstrates that before USA Power met with Pacific Corp and gave them confidential information, they met with Ms. Williams and talked to her about the fact they were going to disclose this confidential information, some of their confidential information to Pacific Corp and as Ms. Banashevits testified, she, being Ms. Williams, made sure that we were going to have Pacific Corp sign a Confidentiality Agreement before we provided that information. So Ms. Williams herself knew that the existence of the Confidentiality Agreement was critical and that nothing was going to be disclosed to Pacific Corp without - and she knew that agreement and that disclosure did nothing to impact whether her information was confidential. These are the notes of her meeting showing that they discussed the Confidentiality Agreement.

The law, Your Honor, moreover, is that a lawyer may not use even publically known information to the detriment of a current client, whether to further a personal interest of the lawyer or to further the interests of another client.

Now I want to turn to the element that Mr. Karrenberg spent most of his time in oral argument on and that is that there is no evidence in this record from which a jury could find that Ms. Williams used or disclosed confidential information of USA Power without its consent. And the first point that they hang their hat on is that Ms. Williams has affirmatively testified that she did not disclose any confidential information to any plaintiff to Pacific Corp. Well, Your Honor, if you look at her testimony, not her affidavit drafted by her lawyers, but her testimony when I asked her at her deposition whether she had discussed anything about USA Power - and this is just at the first meeting with Pacific Corp - and this is her response, "In trying to recall the events of 3-4-03," and that's the date where there was the first in-person meeting with Rand Thurgood that we're aware of, "I do not recall discussing the quantity of water for Power Partners plant." She refers to them as Power Partners but it's USA Power. "And I can't tell you if for sure it wasn't discussed." So when she is under oath and in a deposition, she can't even testify whether she talked about USA Power."

THE COURT: Excuse me. If you don't have this on your presentation, that's fine, that is an answer, correct?

MS. TOMSIC: Yes, it is.

THE COURT: Do you have the question up there?

MS. TOMSIC: I don't have it but I've got the deposition.

THE COURT: That's fine. I know it exists. I just wanted to know if you had it.

MS. TOMSIC: I don't have it on here.

THE COURT: Okay, go forward.

MS. TOMSIC: Now the other thing that's important, Your Honor, is not only does Ms. Williams' own testimony dispute that she never discussed any confidential information with Pacific Corp but Pacific Corp's documents demonstrate to the contrary and I want to start out with the notes of Ian Andrews –

MR. KARRENBERG: Objection, Your Honor. I need to object at this point. This is a supplemental affidavit and there's no foundation for these documents. In fact, these are not notes of Ian Andrews so counsel has just made a misstatement of fact but there's a motion on this.

THE COURT: That was going to be my question. When was that - give me the title of the motion.

MR. KARRENBERG: They filed a Motion to File a Supplemental Affidavit of Peggy Tomsic which was - and these exhibits were attached to it. Both parties have opposed it.

THE COURT: And it's been submitted to me for a decision?

MR. KARRENBERG: Yes, I think in a motion.

THE COURT: I've not considered that motion at this point.

MR. KARRENBERG: Right.

THE COURT: I'm going to allow her to make her argument and allow this argument subject to the Court ruling on that motion.

MR. KARRENBERG: Thank you, Your Honor.

THE COURT: Go ahead.

MS. TOMSIC: Thank you. And, Your Honor, just in addressing that, I want to demonstrate here, regardless of how Your Honor rules on our supplemental affidavit, we've already put evidence in the record to demonstrate basically the same points but this just clarifies and I think tees this up very well and that is these are handwritten notes, at least they come out of a notebook that was identified by Pacific Corp as Ian Andrews notes. It says, "Jody Williams, possibilities. Don Jones, north of Nephi, $4000 plus, Utah Lake" I can't read that word, "pipeline to project, Nephi Irrigation Company for their water, $4000." So according to the Pacific Corp's own notes Jody Williams is discussing possibilities with Pacific Corp in February of 2003 while she's representing USA Power about possible sources of water for Current Creek. She identifies Don Jones, she identifies the amount and she identifies Nephi Irrigation Company and $4000. And why is that significant, Judge? Because the agreement that she negotiated with the people from whom USA Power bought, in this case, Mr. Garrett, Mr. Keats and Mr. Garrett was for $4000. Now the record in this case is that that amount, the amount you pay for water was confidential information. It was not public information. You can't go down to the public recorder's office and say, "Oh gee, how much did they pay?" In fact, Mr. Banashevits testified in his deposition that in fact the price of water was something that they agreed with the sellers they would not disclose and if you look, just comparing those, the amount that she's telling Pacific Corp in February is the amount that she had negotiated. That is a disclosure of confidential information. But that's not the only evidence Your Honor. This is not in my supplemental affidavit. This is in the record before Your Honor, when Rand Thurgood sought to obtain Pacific Corp's authorization to purchase water in April of 2003 he drafted a memorandum asking Pacific Corp and explaining why the investment committee should approve it and he sent a draft of this document to Ms. Williams and I showed this to her in her deposition and she said, "Yes, this is the document Rand was drafting and I was giving some help on." Well, why is that important Your Honor? It's important because when Mr. Thurgood is discussing and Ms. Williams is helping him prepare a memo discussing why Pacific Corp should go out and buy water, it says, "However, of more importance is the current market price for water in this area. This water is agricultural and it runs between $4000 and $4500 per square foot." Well, Your Honor, Mr. Karrenberg says, "Geez, we've got this other evidence that says that Ms. Williams knew water was running from $2000 to $8000 an acre-foot and we expected her to know generally what the price was."

Well, Your Honor, Mr. Karrenberg can argue that to a jury but it does not demonstrate the exact price that was paid for the water we purchased that Ms. Williams knew and was confidential and it doesn't demonstrate the knowledge and information she obtained in negotiating with potential purchasers on our nickel, as our lawyer, in terms of what the market would actually bear. That was our information, Your Honor, and there is nothing in this record that demonstrates that that information came from any other source. But even if there was, this evidence presents an issue of fact for the jury because a reasonable inference from this is Ms. Williams is the source of this information.

In addition, Your Honor, Mr. Banashevits in his deposition testified that one of the people from whom USA Power purchased water, Michael Keats, called him on the phone irrate and this is what Mr. Banashevits said, "Michael was upset that Pacific Corp had offered to buy some water rights from another water right owner in Juab County for the precise amount of money that we had negotiated with him. If you recall, that amount was to be kept secret and there were a limited number of parties who were aware of that price."

And Your Honor, not only is there evidence from which a jury can find that Ms. Williams disclosed confidential information in terms of the price, but there's clear information that Ms. Williams back in at least February - we're looking at these same notes again - and disclosed the people with whom she had negotiated on behalf of USA Power. This isn't a question of just going down to the public office and getting who owns water rights. She is identifying people after she had spent a year and a half going through those records and negotiating with people of people—

THE COURT: This is the same note that's subject of the Motion to Strike?

MS. TOMSIC: It is, Your Honor, absolutely.

THE COURT: Just so I'm clear on this point because I haven't considered that motion —

MS. TOMSIC: Fair enough.

THE COURT: — you're maintaining that this document is someone else's notes, correct?

MS. TOMSIC: What I'm maintaining is this, is one of the documents that Pacific Corp produced in this case —

THE COURT: No, this document that you're displaying now is someone else's, not Ms. Williams' notes, correct?

MS. TOMSIC: No. These are Pacific Corp's documents and notes from a Pacific Corp employee.

THE COURT: Okay, go ahead.

MS. TOMSIC: And it's not only the price that this demonstrates disclosure of, it demonstrates that she disclosed the people that she had narrowed down as possible sellers during the year and a half she had spent dealing with all the possible people down in that area who might sell water. So this is basically the knowledge she acquired in going through that process and in the negotiation she had on behalf of USA Power and this document is not in my supplement affidavit, it's part of the record, this is a bill of Ms. Williams with regard to her work for USA Power. You can see she spent extensive time dealing with Mr. Jones on behalf of USA Power for USA Power and again, this slide just demonstrates, this is clearly one of the individuals she spent a considerable period of time negotiating with on our behalf.

In addition, she identifies Nephi Irrigation Company and again, Your Honor, this is someone that she negotiated with on behalf of USA Power.

Finally, Your Honor, there's also - these are Ms. Willilams' notes –

THE COURT: Just one second. Go ahead.

MS. TOMSIC: In addition Your Honor, these are Ms. Williams notes that she took of conversations or meetings she had with Mr. Thurgood and I asked her that and this is Exhibit 100 as you see. "Is Exhibit 100 your handwritten note?

"Yes.

"And was that conversation relative to your representation of Pacific Corp on a model water matter?

Yes."

And you'll see, she identifies the very person from whom we find out, or USA Power purchased water. It says, (inaudible). So Your Honor, if you look at the evidence in this record, there is clearly evidence from which a jury could find that Ms. Williams disclosed confidential information, that is information she learned during the time she represented USA Power with regard to price, with regard to real potential sellers and what their level of interest might be and what they might be willing sell the water for.

But it's not just those three individuals, Your Honor. These are Ms. Williams notes of a meeting that she attended with Kennecott on behalf of Pacific Corp and then if you look, these are her notes of a meeting that she attended on behalf of USA Power negotiating with Kennecott. She bills us for her meetings and she bills Pacific Corp for her meetings. Again Your Honor, a jury can infer from this evidence that Ms. Williams was using information she obtained during the course of her representation without my client's consent.

THE COURT: How does that last note demonstrate that?

MS. TOMSIC: What that demonstrates, Your Honor, is that Ms. Williams spent quite a bit of time meeting and negotiating with Kennecott on behalf of USA Power and then when she was retained by Pacific Corp she went out and negotiated with them as well and I think that what a jury can reasonably conclude is that the information she gathered during that process of negotiations which was all confidential information and really could not be disclosed without my client's consent was information that she utilized in trying to develop water rights for Pacific Corp.

THE COURT: I was going to ask you how you can do that but I guess your position is that that's sufficient to support a reasonable inference?

MS. TOMSIC: It is, and it's not our only - it's not our only piece of evidence. I think what it does is it shows the litany of the few people she met with and discussed with, were on the catalogue that she narrowed for us.

THE COURT: So, and I understand your linking all these items together but you're suggesting that you can draw the reasonable inference because she met with the same prospective seller, let's say, on the nickel of two different clients, that that's sufficient to support a reasonable inference that she used or disclosed confidential information?

MS. TOMSIC: It's more than that, Your Honor. I think when you get to Kennecott, that would be an accurate description. But when you look at the three people she narrows it down to in those notes from Pacific Corp in February –

THE COURT: Again, I know you're linking them altogether –

MS. TOMSIC: Right.

THE COURT: – but my question - and eventually I will get there, but my question is to this particular item of evidence. Did I hear you correctly, you're suggesting that because she had this meeting with Kennecott that she must have disclosed confidential - used or disclosed confidential information?

MS. TOMSIC: Yes, Your Honor, and I think it's more the used category than that confidential.

THE COURT: I want you to know and when I come to making this decision, I'm going to look at it all collectively but I really struggle with how that can support such a reasonable inference –

MS. TOMSIC: In the –

THE COURT: - particularly this note. It seems like, and I'm sorry I'm cutting you off but –

MS. TOMSIC: No, that's okay. I don't mean to –

THE COURT: – I want to make sure –

MS. TOMSIC: – cut you off.

THE COURT: I'm not offended by it at all. I hope you aren't either.

MS. TOMSIC: No, certainly not.

THE COURT: But I'm struggling with this concept. It seems like a leap to me and not sufficient to support a reasonable inference, at least when you isolate this particular note.

MS. TOMSIC: And, Your Honor, I think in all candor if this was the only thing we had, I would agree with you but I think what it does is it just is one more piece of evidence—

THE COURT: Carried to the end, I mean I guess a lawyer can only represent one client. I mean it would certainly narrow the field of clients a lawyer would be able to represent.

MS. TOMSIC: Well, and I think it's fair to say, Judge, if our entire case was predicated on the Kennecott representation, we'd be on a very thin reed.

THE COURT: I know it's not and I don't want to get into an argument with you but you just stood before me and said that this would support a reasonable inference sufficient to create a genuine issue of material fact. I mean, I don't think I'm miss hearing.

MS. TOMSIC: Not in and of itself - as linked to the other items of evidence.

THE COURT: Okay.

MS. TOMSIC: I don't disagree with you if this were the only thing, Judge, I would not be standing here before you arguing that we have presented evidence of disclosure and use of confidential information.

THE COURT: And again, I don't want to get in an argument with you either but if you link together - and I'm not saying you are, but the reason why I started this dialogue with you obviously is because if you link together 10 facts like that, there is a risk that you're still in the same position, you've not presented sufficient evidence that would support a reasonable inference to create a genuine issue of material fact for a jury.

MS. TOMSIC: And I hear you and I guess what I'm willing to say, Judge, is I'm willing to throw out Kennecott stuff an stand on the other.

THE COURT: I don't want you now to throw out –

MS. TOMSIC: No, all I'm saying is –

THE COURT: – you stood on it just a moment ago before I had –

MS. TOMSIC: No, what I'm saying is I'm willing to throw it out and make the same argument because –

THE COURT: All right. Okay.

MS. TOMSIC: Our position does not stand and fall on Kennecott.

THE COURT: All right.

MS. TOMSIC: Now, the other thing is - and I will get to the question of inference, but the evidence in this case is sufficient for a jury to infer use and disclosure in addition to the evidence of actual disclosure and the reason I say that Your Honor is if you look at Mr. Banashevits deposition - let me go back and get the question.

"Did she also develop confidential information on your behalf?

"Yes.

"Did she use that information to benefit Pacific Corp?

"Yes.

"What is your basis for saying so?

"She duplicated efforts for Pacific Corp in 20 percent of the time that it took her to perform those efforts for us."

And, Your Honor, the facts bear that out. If you look at when Ms. Williams first started looking for water rights for Pacific Corp, it was March of 2003. In August of 2003 she had an agreement. The reason that's important in terms of confidentiality is it's one thing if you have to start at the beginning and go through everybody who may have water rights, figure out what the temperature down there is and get the water rights. It's another thing to take all the information you learned in those negotiations, in that process and immediately go to the people who you know on that work, may have a real interest in what their level of interest is, and if you look at how long it took her to do our information, she's starting in April of 2001 and wasn't able to even do an agreement until August of 2002.

But it's not just the water rights that's we're talking about. If you look at the record before Your Honor of Ms. Williams notes of the meeting she had with Mr. Thurgood on the development of Current Creek, Ms. Williams was really becoming part of the development team for Pacific Corp as she had for USA Power. I want to just show you a couple of her notes of those meetings. With her there they were discussing the air permits. They were talking about the integrated resource plan. They were talking about Utah County being a non-attainment area and the need every five years beginning in 2005 for 500 megawatts. They're talking about the RFP being out. They're talking about Pacific Corp's plant being the cost based alternative. They're talking about emission credits and dry cooling and air credits, and our expert has testified that Pacific Corp did not perform any analysis of the costs and technical feasibility of the use of dry cooling until May of 2003. Shaw, Stone and Webster - and these are the EPC contractors - submitted its cost estimates and design for the plant on or about June 9, 2003. And you remember from reviewing the record Your Honor that Pacific Corp submitted its bid on I believe it was the 17th of July 2003. So shortly after a month.

And what our expert concludes - and this is in the record - it is work that could not have been directed or completed within that 4-month period without knowledge and use of plaintiffs confidential information.

And my point is again, there is evidence in this record from which a jury could find that not only could Ms. Williams not have obtained the water for Pacific Corp in that period of time necessary to submit the bid but there is evidence from which a jury could find that her participation as a member of that development team on the exact project and the exact competition for the project that she had for USA Power, they can infer that she used or disclosed confidential information, whether it was intentionally or inadvertent.

And Your Honor, Mr. Karrenberg says that under Utah law there is no question that for a plaintiff to bring a breach of confidentiality case, in this case, USA Power must show that that lawyer actually went over and handed the confidential information to the second client. Well, Your Honor, the Utah Supreme Court in Kilpatrick, the Utah Court of Appeals in Shaw, the Utah Supreme Court in the Gildia case did not address the issue. It has not been ruled upon by a court in this state whether under circumstances of adverse representation from the circumstances where a lawyer does the same thing for client A, does the same thing for client B, those two clients at the same time are competing for one contract, an inference cannot be drawn of use or disclosure.

And I want to just look at a couple of cases from other jurisdictions and then come back to the Kilpatrick case, the Shaw case and the Gildia case. Cases from other jurisdictions when faced with the issue, when they had the precise issue before them, said an attorney is presumed to be using confidential information of a prior client - this is a prior client, not even a current client - if the matter in which he represented the former client is substantially related to the present action. And this is a situation where the Court said, Look, we're not going to hold an irrebuttable presumption but we believe where you have a breach of fiduciary duty case and you have a lawyer representing two clients which create a conflict, a jury can presume that there was use and disclosure and the defendant then can come forward and put forth his defense and it's up to the jury to make that decision.

But it's not only the cases on presumption, Judge. There are cases in other jurisdictions that have squarely addressed the question of inference and in this particular case, the Chrysler case which is probably the cornerstone case, the court held, "The evidence of a relationship or lack thereof between the cases are facts that the jury may consider in determining whether it should draw an inference that confidential information was used. Neither party is entitled to summary judgement."

Another case that said an inference was proper, it says, "In a claim of legal malpractice a showing of a substantial relationship between the matter for which the attorney represented the former client and the subsequent materially adverse representation may allow a reasonable juror to draw the inference that the client's confidences have been used against him in contravention of the attorney's continuing duties of confidentiality and loyalty." And Your Honor, I want to say that we have put in sufficient evidence of actual disclosure and what I'm saying is, there is additional evidence in this case from which a jury can either presume or infer use and disclosure which I've gone through.

And I want to talk about the cases that Mr. Karrenberg talks about and I want to talk about the Shaw Resource case first and I think the most critical thing, Your Honor, if you read Shaw - and I know that Mr. Karrenberg represented the defendants in that case –

MR. KARRENBERG: Only one.

MS. TOMSIC: – but I think what's important from that case is, Your Honor, before the court ever, ever addressed the issue of confidentiality, the Court of Appeals expressly held there was not adverse conflicting representation. In this case there is absolutely a foundation - and we'll deal with it in the breach of loyalty claim - of adverse conflicting representation.

The second thing that's important about Shaw is in Shaw, the plaintiff consented to the fact that the lawyers were going to represent the other defendants. Not the case here, uncontroverted.

And the other thing that's important, is unlike Shaw, we do have evidence that Ms. Williams used or disclosed plaintiff's confidential information. So the Shaw Resource case, Your Honor, has nothing to do with whether the court should infer or presume, excuse me, whether a jury should be allowed to infer or presume use or disclosure of confidential information because the court held it was an adverse, conflicting representation.

I want to talk to you about the Kilpatrick case. There's two cases. There's Kilpatrick 1 which is the Court of Appeals case and the court in Kilpatrick 1 never addressed the issue of confidentiality. The only issue was a question, whether there was a question of fact regarding causation and the court held there was and reversed the district court's ground on the judgment.

Kilpatrick 2, there's no question there's language in Kilpatrick 2 that the defendants have grasped onto and frankly, if I were in their position I'd do the same thing but if you read Kilpatrick 2, the supreme court did not have before it the issue of whether there could be an inference or a presumption. The only issue before the Utah Supreme Court was whether the trial ourt had erred in finding that as a matter of law there was an attorney/client relationship at the time of these events. The supreme court said you can't do that, it's an issue of fact for the jury, you've got to send it back and reverse and remand it and in the course of doing that, the Court said, Well, gee, this is pretty complicated, let me look at a couple of things and maybe we can help the trial court but there is not a ruling in that case, not a holding, as to what the rule is on inference or presumption.

More importantly, if you actually look at the discussion which with all respect for them is dicta, if you look at their discussion on confidential information it's important to understand what the facts of that case were and Mr. Karrenberg is wrong in terms of what the adverse representation was and I know it because I represented Wiley, (inaudible) and Fielding and I handled the trial on the appeal. The issue in that case - and you can look at the opinion - was whether or not my clients disclosed financial information to North Star, another client, in the course of negotiations between the two parties to obtain financing to buy the license for Channel 13. North Star and the plaintiffs were not competing for the same license. It's a situation where you've got negotiations. The only claim the client had in terms of confidential information was that Wiley, (inaudible) Fielding gave confidential information to North Star that North Star used to leverage them in the negotiations and the court said when it was discussing guidance, it said, Look, the only evidence that there is right now is the confidential information that you the plaintiffs gave to them. You've got to have more than that. But the court never addressed the issue of whether, where you have simultaneous advise representation of a client doing everything for both parties, an inference would be proper or a presumption would be proper. That is not ruled upon at court and it was not presented to the court and even though the supreme court said, Gee, the only evidence it seems you have is evidence you gave to North Star, it said, send it back to the trial court. It didn't rule as a matter of law that there was no breach of the duty of confidentiality.

And again, unlike Kilpatrick, we have identified information Ms. Williams used or disclosed that was not given to Pacific Corp. And in addition, unlike in the Kilpatrick case, the information that we did share was subject to a strict Confidentiality Agreement which was not the case with

North Star.

The Gildea case really has nothing to do with this, Your Honor. In Gildea, the Utah Supreme Court simply ruled that there was no attorney/client relationship between the plaintiff and the defendant. Accordingly, the defendant did not owe the plaintiff any fiduciary duty whatsoever. There as no analysis addressing whether a jury could infer use or disclosure of confidential information based on an attorney's simultaneous adverse representation. So in truth, in Gildea again, the Court did not address this issue.

And finally, Your Honor, Mr. Karrenberg alleges –

THE COURT: I'll limit you to five more minutes. Can you do that?

MS. TOMSIC: This is it.

THE COURT: All right, go ahead.

MS. TOMSIC: In terms of the Pacific Corp information disclosure, first of all what was disclosed to Pacific Corp didn't include everything. Potential sellers (inaudible) spent almost two years waiting with the negotiating with, the negotiating tactics in the negotiations, all of the analysis, research and efforts in selecting the numerous power plant ingredients while she was a member of their team; and second, we have evidence she still used or disclosed it and the fact that Ms. Williams and Pacific Corp can point fingers at each other is legally irrelevant and does not remove liability from either.

Let me give you an analogy. If we had two surgeons in an operating room, suppose to take off Mr. 'X' right leg. He comes out, his left leg is missing. Both surgeons said, I didn't do it. Does that mean they're both relieved of liability, Your Honor? That's not the situation. Where you have two people with duties and you can demonstrate harm, they're both liable or one is liable and it's up to the jury to make that decision, not a court as a matter of law.

So in sum, Your Honor, based on the evidence - again this is a Motion for Summary Judgment. We've presented evidence from which a jury could find that Ms. Williams had confidential information and we have presented evidence from which a jury could find that she used or disclosed it without my client's permission.

THE COURT: Thank you, counsel.

Mr. Karrenberg?

MR. KARRENBERG: Thank you, Your Honor. Am I obligated to use the same amount of time? I'm just kidding.

THE COURT: I know you are.

MS. TOMSIC: Your Honor, let me introduce you. This is Chad Peterson my co-counsel.

MR. PETERSON: Your Honor, Chad Peterson may it please the Court.

THE COURT: Thank you, counsel.

The first point is in demonstrating adverse representation, Your Honor, is when Pacific Corp retained Ms. Williams they made it clear to her what they wanted her to do. It wasn't just go find us water for some abstract power plant - and this is her testimony. I'm asking her what Mr. Thurgood said to her in the conversation where he's calling her and asking her to represent Pacific Corp on Current Creek. "I don't recall the exact conversation but the substance was that Pacific Corp was considering building a power plant in the Mona area."

There is no question when she was approached by Pacific Corp that she knew she was being asked to assist them in getting water for a plant in Mona, Utah, no question about it.

And Mr. Karrenberg called my clients liars because he said more than one plant could be built down in Mona. Well, Judge, there's certainly in this evidence to the contrary and you know, using (inaudible) doesn't mean it's entitled to summary judgment and it certainly doesn't reflect the state of (inaudible) or the character of my clients.

If you look at Ms. Williams' notes of the meeting, Exhibit 61, Pacific Corp tells her there's no plans to even do the 7500 megawatt plant, air won't allow an additional plant.

Then if you look at Ms. Williams testimony when I showed her those notes, she said, "In the meetings that I attended with Pacific Corp my recollection was that they weren't planning to do a second 500 megawatt power plant at the site." Her own testimony based on what her stated knowledge was and what Pacific Corp intentions were, demonstrate there was not an intent and there wasn't an intent because of the air permit issues.

Then if you look at Ms. Williams' memorandum to Mr. Thurgood in September of 2003 she states, "Pacific Corp or someone else will build a plant near Mona and well need water." This comes from the in-house counsel of Pacific Corp, Mr. Jenkins in his deposition and I asked him, "And during 2003 did you also understand that once Pacific Corp made the decision to build Current Creek that it was not going to accept any other proposals submitted by USA Power relative to the Spring Canyon Project?"

Let's go to what Mr. Jenkins says, "My understanding was that once the Current Creek Project was selected that no other responses to that RFP would be selected."

Now the other thing that Mr. Karrenberg says is, Gee, you know, Ms. Williams went out and got water, but if you get water, water's not a big deal, it doesn't make it adverse. Well, it does, Your Honor. Not only is there evidence that only one plant could be built, but there's was going to compete in the RFP and Ms. Williams never told them she was representing Pacific Corp in their competing power plant and never said, Well heh, I don't represent you any more. Evidence from (inaudible) simultaneous, she was simultaneously representing both USA Power and Pacific Corp on competing power plant developments when she knew only one power project was feasible and only one project would be selected and she acquired water rights for Pacific Corp when she knew there as a distinct possibility for water rights. Pacific Corp was applying (inaudible) USA Power's water rights and representing Pacific Corp even though she was simultaneously representing USA Power in its negotiations with USA Power.

Causation. Judge, you know, it's always a good thing to look at the law to see what the risk standard is and in Kilpatrick, the court set forth what the causation standard is in a legal malpractice action predicated on breach of fiduciary duty and this is what they said, "But for defendants breach of fiduciary duty a reasonable likelihood existed that the plaintiffs would have benefitted." That's the legal scenario for causation, Judge.

The Kilpatrick Court went on to say, "Generally causation cannot be resolved as a matter of law. Proximate cause is an issue of fact; thus, only if there is no evidence upon which a reasonable jury could infer causation is summary judgement appropriate. Because proximate cause is an issue of fact, we refuse to take it from the jury if there is any evidence upon which a reasonable juror could infer causation" and it's not a question of just one little piece of evidence demonstrating causation. Let's look at what Mr. Karrenberg says - never mind.

First of all look at the key material facts regarding causation that we put forth in this record and then I want to deal with what Mr. Karrenberg says is undisputed. USA Power was identified by Pacific Corp as owning the only viable project site - and these are all facts from which a jury can find causation. Pacific Corp wanted to purchase USA Power's development for $3 million plus a joint development agreement. Williams switch sides and simultaneously represented Pacific Corp on a competing power plant development without USA Power's knowledge or consent. Pacific Corp's plant couldn't be built without water. Pacific Corp couldn't win the RFP without water. Williams assured Pacific Corp she could secure water in accordance with Pacific Corp's artificially short time frame. Pacific Corp terminated negotiations with USA Power when they secured the water necessary for Pacific Corp's competing plant and helped Pacific Corp in the RFP and CC&N process. Pacific Corp awarded itself the sole RFP process. USA Power's RFP bid was second. Those are all facts in this record that they may dispute but they're there, that demonstrate causation, Your Honor.

And let's look at what Mr. Karrenberg says is undisputed. It's undisputed that Holme Roberts assisting Pacific Corp to find water for Current Creek could not have caused the circuit court to reject Spring Canyon's assets. Not true.

Let's look at the record. USA Power at the time Ms. Williams was retained by Pacific Corp, according to Pacific Corp was the only viable power project that could meet the 2005 peaking demand contract. And I'm quoting from their memos. The only viable project site that was capable of meeting a 2005 online deadline. Pacific Corp was "unaware of other entities capable of meeting that April 2005 date, the only project that has any possibility of meeting the peaking for 2005 or even in 2006 commercial date.

USA Powers. USA Power had obtained - and this is what Mr. Thurgood told Mr. Banashevits - "USA Power has obtained a competitive advantage that would take Pacific Corp two to three years to duplicate and several million dollars" and that was in August of 2002, Your Honor. USA Power had done so much work on the project that nobody stood a chance to beat it, that's what Mr. Thurgood told him when he said, we're not going to buy your assets, we're going to issue this RFP but you guys are the ones. Evidence is that USA Power and Pacific Corp had an agreement in principle.

Ted Banashevits. "We came to a conclusion we would sell the assets to Pacific Corp for $3 million and there would be a long-term consulting agreement. We scheduled a meeting in Portland to complete the transaction." They go to Portland and Pacific Corp ends the negotiations. She starts working for them the beginning of March, he terminates March 17.

Your Honor, that demonstrates causation, that is a piece of evidence or pieces of evidence from which a jury could find that Ms. Williams breached her fiduciary obligation by representing conflicting adverse interests, caused the sale to fail.

Now what else is undisputed that shows no causation? That there was nothing unique or special about the services Holme Roberts performed. She did nothing more than any other water lawyer could have done. Well Judge, that's their theory of the case. That's their theory and what we have is if Ms. Williams had not been available, who would have been the person they would have used? This was the question posed to Mr. Thurgood who actually contacted Ms. Williams and hired her. And they say, Oh, anybody could have done this. Well, we asked him, Well, who would you have used if Ms. Williams couldn't have done it?

"I don't know.

"Have you ever used another attorney on any water issues besides Ms. Williams?

Mr. Thurgood: "No.

"Have you, for example, ever interviewed another attorney?

Mr. Thurgood: "No.

Another lawyer could not have - and these are from the record - told Pacific Corp the exact same price that USA Power had confidentially paid for its water rights, negotiated with the same pool of potential purchasers Williams contacted as USA Power's lawyer and it's not the list you get from the public record, it's the few individuals she had honed down who might really be interested, what their level of interest was and what their price levels were, achieved results from Pacific Corp in a fraction of the time it took Ms. Williams to accomplish the same results for USA Power, relied on the relationships Williams had previously established. And Your Honor, remember, Ms. Williams was working on USA Power's behalf for over two years. She was down dealing with the people in Mona. She'd established relationships.

Now if Pacific Corp knew Ms. Williams had represented USA Power and Pacific Corp discussed Williams conflict with its in-house counsel and created an issue, why didn't they just hire another lawyer if somebody else could have done it? They didn't, Judge, and Mr. Jenkins affidavit we'd move to strike because it's three paragraphs. There's a paragraph that says, Geez, I was prepared to hire somebody else who would have done the same thing.

Well, Judge, that's inadmissible. There are no specific factual foundation for it, it's conclusory and in any event, the person who hired didn't consider anybody else and there's clearly evidence that nobody else could have done it which is why they didn't hire another lawyer. Again, we've already seen these demonstrating how important her participation was.

And again, back to Mr. Karrenberg's point on causation is they say there's no disputed issue of fact because Pacific Corp - and (inaudible) weren't competitors why. Because Pacific Corp's decision to build a plant did not defeat our plan and it's undisputed that plaintiffs should be free to build a plant and sell power to (inaudible). Judge, that's their arguments to the jury. The question is, is there sufficient evidence in this record in which a jury could find that once she switched sides and helped Pacific Corp get the RFP, what did that do? Well, according to the evidence, there wasn't going to be a second power plant. The air permits couldn't be obtained.

Ted was asked whether construction impacted their ability to develop the project. He said absolutely. And he was asked where and he says, there are several critical aspects of a power plant and each of those are limited. There is a finite amount of room in that Mona switching station, there is a finite amount of water in the county, there's finite amount of room in the air shed in order to (inaudible). The answer to your question is absolutely.

That's in the record, Judge, and it's not only is opinion. Our expert witness, Mr. Koltic who is experienced in the development of power projects, testified in the case of - excuse me, let me go back. In the case of Spring Canyon, Pacific Corp's decision to build a 7500 megawatt Current Creek Project near Mona essentially terminated the viability of the Spring Canyon project because of many factors including transmission restrictions, market limitations and water use issues. If Mr. Karrenberg wants to cross examine him and disagree with him before the jury, great, but there's evidence in the record.

Not only is it a matter of the physical ability and restrictions, Mr. Olive who I've introduced to the Court also an expert in this case, in his report testified and it's his opinion, USA Power's responsible business did not actively pursue any other opportunities in the market for the Spring Canyon Project during that year plus time. It did not do so to show its good faith intention to consummate a deal with Pacific Corp. It did not do so because all it's time and economic resources were required to pursue the Pacific Corp opportunity. After Pacific Corp in November 2003 announced it had selected Current Creek as the winner of the 2003 ARP and the Public Service Commission awarded the CC&N to Pacific Corp for Current Creek in approximately April 2004, the window of opportunity for the Spring Canyon project has essentially closed.

And Your Honor, he goes on to testify in his report - and also in his deposition - that they tried to find a buyer but the bottom line was, Pacific Corp wasn't a (inaudible) it was built with the specific idea of meeting a power demand using the Mona switching station. And if you look in Volume 10 or Exhibit 10, Volume 1 of the confidential information, there's a marketing study in there that targets Pacific Corp as the most likely purchaser of power from that plant. So that window of opportunity was not only an economic targeted window of opportunity but it also was not feasible from the constraints, the environmental constraints, public relations standpoint.

Mr. Karrenberg says again it's undisputed that Pacific Corp's bid was (inaudible). You heard him say that not only in his papers but today. And they say they decided to build a second 500 megawatt plant and that's back in September of 2003. Well, Judge, there's no second plant there and according to what they told Ms. Williams, they had no intention of building it and this idea of suddenly attaching an RFP that was put out in June 2007, never disclosed to the parties, only attached to their (inaudible) which we move to strike, doesn't make it any different. We're talking, let's see, five years after the fact they decide to put out a bid. It doesn't mean any plant is going to be built. It doesn't mean that we weren't caused damage in 2003. We're not required to sit around five, six, seven, eight years until Pacific Corp decides it wants to do something else.

THE COURT: Counsel, I'm going to give you five more minutes and then we're going to recess until 1:30.

MS. TOMSIC: Okay. I want to look at the only evidence that they put in for their position. It's an evidence report. This is the only evidence for their position. This is what it says. "The result of these discussions was the final ranking of offers relative to the (inaudible) was captured in the round four ranking summary." So this is this round four ranking summary shows how are they ranked in response to the 2003 RFP. Well, what does it say? Here's their ranking and defendant's own documents, sole documents. Spring Canyon Energy not only placed second, it also placed third on this bid. But look at the documents that they ignore.

Ms. Banashevits testified in her affidavit that when the application was submitted to the Utah Public Service Commission, there was a data room, Pacific Corp's document and one of the documents that were in the data room is this document, Judge. This is one of the documents demonstrating what they did with the bids, Pacific Corp. If you look at the bid number, we're ranked second. So again - and that's in July of 2003. If you look at their own emails, Spring Canyon came in second. They're not being pursued because the peaking (inaudible) is the most economic choice in the peaking category. So they are disputed.

And, Judge, what isn't disputed are very critical. Number one, Williams never disclosed her representation of Pacific Corp to USA Power. She clearly admits it as does the other lawyer who worked on the matters. Williams never obtained USA Power's consent for adverse representation, clearly demonstrated. Three, USA Power contacted Williams as soon as it discovers her adverse representation. Dave Graber's email of 11-6-2003 in which he said, "In reviewing the recent water rights activities going on the Juab County specifically regarding Pacific Corp's competing power plant which they announced yesterday, it appears that you may be in a conflicting position as our attorney. I think that this is a serious matter and I'm surprised and extremely disappointed that you did not contact us regarding this possible conflict before accepting such an engagement. Would you please call me to discuss this matter and answer my concerns?"

Well, what did Ms. Williams do when she got this? She contacted Pacific Corp. Here are notes of Pacific Corp dated 11-7, the day after this email and what did Ms. Williams tell them? Spring Canyon is really mad, worked for competitor.

Well, I'll tell you what she didn't do and it's undisputed, she never responded. She never responded to the email. Look at her answer to our request for admissions. Williams believed that Dave Graber's November 6, 2003 email was simply an attempt by USA Power Partners to avoid paying its account at HRO and therefore she did not communicate with Dave Graber relative to that email. Well, look at the amount of this. $310 that she claims that's why he sent the email after they'd paid $100,000. There's a good reason that she didn't respond to this email, Judge, and it goes back to our theme, she who has two masters to serve must lie to one of them. Thank you. You've been very patient.

THE COURT: We'll recess and reconvene at 1:30.

(Whereupon a noon recess was taken)

THE COURT: Mr. Karrenberg?

MR. KARRENBERG: Your Honor, just two questions. First, you mentioned this morning planning to announce your ruling on October 5. The implication was you were going to announce it in court. Do you want us to reserve some time in your house and we have the evaporative kind, the kind that Spring Canyon said they were going to put on theirs is the air conditioner kind where the air (inaudible) type of cooling that goes on here and cools the air going in. Rather than get rid of the hot exhaust that comes out of the back of this huge engine, they make additional electricity with it and the way that they do that is they heat water into steam. There's a piece of equipment that's a big boiler and it heats water into steam. They call it a heat recovery steam generator or they abbreviate it in the industry as a HRSG and the hot exhaust comes out of the back of this great big jet airplane engine and heats water into steam here and the steam goes through piping, literally. It's piping like this with about eight or nine inches of insulation around it and that goes over to a steam turbine generator that generates even more electricity and the electricity runs from this generator over to the switching station and into our transmission lines.

After the steam has been used here, they recirculate it but they have to get water back into water droplets and there are two different ways that they can do that. One is to route the steam through a big piece of equipment called an air cooled condenser and it's just like a radiator on a car. You know how on your car you look down at the radiator and little leaves will get stuck in there and if you run your thumb across you can snag on the pins on your automobile radiator. This thing has a radiator that looks just like that only it's huge and instead of having a 15 or an 18 inch fan like you'd have on your car, it has 30 of them and they're 34 feet across. They blow a tremendous amount of air up into this radiator and the steam is cooled into water droplets and it's collected in the tank and the water simply goes back through the system.

There are two different ways of cooling the steam. One is to have this air cooled condenser that's just like a radiator in your automobile and the other way to do is having pieces of equipment that they call cooling towers. They have water circulating in it and the steam comes into contact with these chilled coils and it's condensed back into water droplets that way.

Ours has an air cooled condenser. After the water runs through this cycle several times it gets cruddy and so they have to drain it out and it has what I liken to a spit valve on a trumpet or a trombone. They get rid of some of the water that's been running through the cycle in order to get rid of the crud that's accumulated in it. There are a couple different ways to get rid of this cruddy water. One is to discharge it into a lake or a river. The government has something to say about that and you have to get a permit if you want to do it. The other way to do it is to dig a clusters, that was absolutely confidential information and I note that Mr. Racine in his deposition stated he considered his work product to be confidential and he was not at liberty to share it. The transactional details, I think we've had exhaustive testimony that we considered those details negotiated by Ms. Williams to be confidential and as to the financial details, I believe we have testimony that we considered all of that to be proprietary, work product and indeed it was all stated confidential.

THE COURT: How would you describe your client's burden of proof in the context of this Motion for Summary Judgment?

MR. PETERSON: Your Honor, under Rule 56 I don't see us having - I think we have to identify that we have a trade secret and that's what I'm prepared to do today. We have to show there's a contested material fact regarding the existence of that trade secret and I'm prepared to do that today. I think in the case of the Utah Medical Products in Munia cases, you had fact specific inquiries in which you have a doctor that left a medical practice - and there was affirmative evidence that in one case - well, let's take the medical products case. In the medical products case which is decided under Utah law, you had a doctor that left a medical practice and took with him three boxes of information. It's like 17,000 documents but there as inventory taken, there as no representation that this is confidential information but for him taking that, he would not have otherwise known it. The facts were very vague (inaudible) Utah Products and the Court looked at it and said you know what, you have delineated a trade secret per se, you haven't stated a prima facie case. In the Munia you had a doctor who had left a medical practice and basically, using preexisting knowledge and he published academic articles on the medical device, continued to sell and market medical device that he had knowledge of before he had his medical practice. So, in those two situations I think you have unique facts. This, Your Honor, is different in that it's a commercial transaction. You have two commercial players coming together, you have a confidentiality agreement signed and you have information that's transferred that is marked confidential and once I get to my presentation I'll be able to show the time line.

THE COURT: Go ahead.

MR. PETERSON: Anyway Your Honor, that was (inaudible) and let me get started here.

Your Honor, once again, one of the summary judgement standards, as I said, we don't need to disprove the factual defenses of the defendants although we're prepared to address those. We need just to show there is a contested issue of fact supporting our claims.

relying on than the air cooling that you say meets the definition of a trade secret?

MR. PETERSON: Well, Your Honor, once again, I think it also goes back to the financial assumptions because as you'll see –

THE COURT: Well, I know, but I was asking you about the items listed on Lines 10 through 17, not the financial data or that information. I recognize that's a different category. I'm trying to - I'm looking at what I'm assuming to be the, you know, the hard mechanics of the power plant and you're maintaining that this combination is an aspect of your client's trade secrets.

MR. PETERSON: I guess what I'm saying is, Your Honor, the hardware in the ground is not a trade secret. What is –

THE COURT: Well okay. Let's start there –

MR. PETERSON: The hardware in the ground –

THE COURT: The hardware in the ground is not –

MR. PETERSON: – that's not the trade secret.

THE COURT: Nor is the manner in which the hardware in the ground is configured a trade secret?

MR. PETERSON: That can be because as I said –

THE COURT: Not can be, I want to know what your maintaining to be a trade - I hope you're not bothered by my questioning –

MR. PETERSON: Oh no.

THE COURT: — my questioning exemplifies my struggles with this particular issue.

MR. PETERSON: Your Honor, the essence of our trade secret is the evaluation, the testing, the modeling, the work product that we put in to pull together this combination of factors, okay? Like I said, Your Honor, the hardware in the ground, that in and of itself is not unique but the method in which it's pulled together, the way one fit piece fits with the other, that work product that underlies that decision, that evaluation, that is absolutely a trade secret and that is why, by the way —

THE COURT: Again, and I'm not - I'm sorry for splitting hairs here, I'm just trying to enlighten myself.

MR. PETERSON: Yes, sir.

THE COURT: Do I hear you saying then that the physical connection of the items that are listed in Lines 10 through 17 which make the physical components of this power plant, are not one of the trade secrets that you are claiming because these technologies are known in the industry or readily assessable in the industry by Pacific Corp.

MR. PETERSON: Your Honor, I guess I'd analogize it this way, if you go —

THE COURT: Can you answer that question first before you give me the analogy?

MR. PETERSON: Yes, sir. I guess what I'm saying —

THE COURT: Is it a bad question?

MR. PETERSON: No, it's a good question. They're all good questions when it comes to the bench. Your Honor, I think once again, the combination of the details, the combination of the different components —

THE COURT: I'm looking at the components that are listed in 10 through 17.

MR. PETERSON: Right.

THE COURT: I'm not talking about any other factors, I'm looking at the components —

MR. PETERSON: Yes, sir.

THE COURT: — and I'm trying to understand what it is about the organization of those items that constitute a trade secret if you are claiming this to be one of the trade secrets that was misappropriated.

MR. PETERSON: Your Honor, let me answer the question this way. What is the trade secret is the financial viability, the viability of these factors put together. The factors themselves are not extraordinary. Air cooling is unusual but they themselves are nothing that's novel, for example, but it's the work product that was put in to pull these factors together, that is the trade secret. It's the viability. It's the proof of viability. That's the trade secret. I'll get to this in a second, Your Honor, we showed that this type of plant would be successful at that site, at that location and that, Your Honor, that is the information, that is the value that we gave to Pacific Corp.

Now this is our expert report that speaks to this issue and this talks about, once again this is the similarities, dry cooling, zero water discharge, natural gas source, transmission - one thing I want to talk about, the zero waste water discharge and the dry cooling. These two elements were the subject of continual testing by our engineer team for a year to 18 months both due to performance evaluations, gate cycle test, the water tables that were put together and in order to find the correct configuration with the air cooling, 500 megawatts, G7FA, all of these combinations put together, we tested different types of turbines. We tested air cooling versus water cooling. We tested all different types of combinations of these details. We put it together. We did that after literally years of testing by our engineers and this is the combination that we came up with and so, Your Honor, once again, individually the parts may not be a trade secret but the testing to put them together in the assuming combination, that is the trade secret, Your Honor.

Your Honor, this is once again just restating the tests from 3M vs. (inaudible), the courts have found sufficient circumstantial evidence of misappropriation based then May 2003 they formally decide to use dry cooling.

Once again, Your Honor, if I could back to the Learning Curve Toys case, Pacific Corp was caught with a challenge, how do we develop a plant that can be online by 2005? Well, we know Mona is a pretty good location but man, there's no water there and that elevation makes it so difficult to do an air cooled plant, we've never done an air cooled plant. We came forward to them with the solution. We showed them that it could be viable and that's what we did and based upon that after they received that information, suddenly they knew about Panda for years, suddenly they turned on a dime and they (inaudible) site and suddenly they're moving forward at that location without any other options.

And then in June of 2003 Pacific Corp obtains a project cost analysis. Okay. Despite the fact that we don't have any smoking gun documents that we can put forward saying, Gee, isn't great that we stole Spring Canyon's information, the bottom line is put forward a web of evidence, we put forward an issue of material fact as for a trier fact could determine that they misappropriated the confidential information we gave them, particularly regarding the feasibility of a project at Mona, Utah, the site specific feasibility.

THE COURT: And again, the most important factor you're relying on for that site specific evaluation is the feasibility of the dry cooling process at Mona?

MR. PETERSON: Yes, sir.

THE COURT: Is that your strongest point?

MR. PETERSON: Yes.

THE COURT: Is it your only point that you're relying on in identifying it as the trade secret?

MR. PETERSON: No, Your Honor, because as I said, the overall combination of details is the fact we showed that project to be profitable. It's the air cooling —

THE COURT: Profitable as a dry cooling facility.

MR. PETERSON: As a dry cooling facility, yes, Your Honor. I mean, we showed that basically the entire project would be viable but the dry cooling is as I said, that's where you need to have specific testing, precise testing and we were the only ones that did it.

THE COURT: Move on. Thank you.

MR. PETERSON: Now let's talk about the four undisputed facts that Pacific Corp has raised.

THE COURT: How much longer do you think you have?

MR. PETERSON: Can I do it in 20 minutes, Your Honor?

THE COURT: Can you do it in 10?

MR. PETERSON: I'll do it in 10. All right.

(Inaudible) four undisputed facts. These are core plant.

Okay, once again - I think in reference to the work of Shaw Stone, the work of Shaw Stone happened after the fact. The work of Shaw Stone came after the site had been selected and after they had already decided they could go forward with an air cooled plant.

Okay, so you can see this starts in April 2003. Once again, this is after they had already made a decision to go for it exclusively at the Mona site. So this is really after the fact. And just once again to stress the dry cooling (inaudible), you saw that.

(Going rapidly through slides).

Okay, this is once again whether or not our trade secret was really a secret or whether or not this information, the work product involved in our project was actually in the public view. The question is, could you have found out all this information from public sources? Looking at the Notice of Intent, once again, despite the fact they had Notice of Intent in hand by August 15, three weeks later they signed a non-disclosure agreement with us. So, either they were getting very bad advice or else they just said, heh, we want to learn more about these guys project.

And this is information we looked at earlier.

This is an interesting bit of - from the deposition "did you evaluate the (inaudible) of the project? We began a process." This is Rand Thurgood's deposition, talking about his review of Spring Canyon. "We looked at the (inaudible) file and we took it into consideration that they had said at the meetings that if you turn that evaluation, that's as far as it went.

"Did you actually reach a conclusion at that point?

"Answer. No, we didn't have sufficient information."

These are things that were not disclosed in the application, the NOI, the feasibility of using an air cooled plant, feasibility of two on one combined cycle, operate at Spring Canyon, restrictions of the air permit, within the boundaries of the water supply, in other words, the water tables; the fatal flaw analysis showing the transferability of the electric power. These are all items that were not in the NOI. Sales contracts; the contractual terms for the land and water in Juab County; the opinions from Jody Williams regarding water rights that we had under contract; all the economic assumptions; preliminary cost breakdowns; detailed economic analysis, 40 pages of single spaced calculations amortized investments; factory cost of fuel supply; financing for long term power purchase agreement and (inaudible) we showed the overall value of the project based on the price of gas, all the input costs and how it could actually be a viable project.

This is just my client's words, all the items that were not in the Notice of Intent.

Once again, this gets back to an interesting case we found from Coca Cola and the formula for Coca Cola is one of the best known trade secrets in the world even though it's printed on the back of every can, like right there. But the question is, how is it put together? And all of that public information, you could not from that public information reverse engineer the project to see whether or not it would be successful. You could not have a feel for whether or not you had a viable project. That was something you actually had to go and do the research, do the evaluations and evaluate the different configurations and that's what we did and we did that so we could be first in the market with a successful plant at that site. No one else had showed that a plant could be successful at that site. We shared that position with Pacific Corp and like I said, it turned on a dime and they went ahead and built a plant there and they did that without doing the type of preliminary analysis and comprehensive analysis that you would need to do to site the plant at that location and the plant that they did build was identical in all meaningful aspects to what we had shown them when we first met with them in the fall of 2002. Thank you.

THE COURT: Thank you.

MR. PETERSON: Thank you, Your Honor.

UP&L Exhibit____(HLF-3R)

NAVIGANT
CONSULTING

CONFIDENTIAL

NAVIGANT CONSULTING'S FINAL REPORT ON PACIFICORP'S RFP 2003-A

PACIFICORP

February 11, 2004

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NAVIGANT
CONSULTING

Notice of Confidentiality

Navigant Consulting, Inc. ("CI") has prepared this report for PacifiCorp regarding its RFP 2003-A process. Information contained herein is privileged and confidential and is intended for review only within PacifiCorp and by the appropriate regulatory agencies under confidentiality protections.

NAVIGANT CONSULTING

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that they would offer their product under WSPP Schedule C with liquidated damage provisions for all hours of delivery, something that PacifiCorp had requested of them. However, discussions in the context of the RFP ended in part because TECO could not obtain firm delivery for their product for the years proposed. In effect, the firm transmission rights that were needed to support the proposed transaction could not be secured. They could only secure one year (i.e., 2004). Additionally, the pricing for their revised offer for the firmness afforded by their updated product offer made it economically unattractive. As such, discussions with TECO within the RFP were concluded.

Bidder: **Celerity**
Bid Number: 420
Discussion: Celerity's offer was for a unit contingent daily fixed price strike option involving capacity and energy delivery at Four Corners. Total capacity offered was 7 MW with firming reserves provided by Public Service of New Mexico. The proposed product would have been set under WSPP Schedule C with reserves that would have created a firm product for PacifiCorp. The biggest hurdle relating to their offer was the fixed capacity charge, which was priced such that the unit would be out of the money 95% of the time. Even when modeled just looking at July and August, the frequency of dispatch would not have allowed PacifiCorp to adequately cover the fixed capacity payments that would have had to be made. Due to these unattractive economics, discussions with Celerity were concluded.

ii. Peaker Offers

The peaker bid category offers ran the gamut of equipment configurations, heat rates, and delivery points. Out of the 28 offers received, 10 of them were short listed for further clarification based on their ranking according to the RFP screening criteria. Initially, only two offers, the offer from Encore and one from Duke were viewed as being more economic than PacifiCorp's NBA. In spite of this fact, NCI recommended to PacifiCorp that it hold clarifying discussions with three to five potential counterparties assuming the indicative economics of their offers warranted further consideration, i.e., that they were within a reasonable range of the NBA's relative economics. Clarifying discussions were then held with the five bidders behind the top ten offers. At the conclusion of these discussions, PacifiCorp prepared a revised ranking of the offers (Round II Ranking) that reflected PacifiCorp's most current understanding and valuation of the offers (See Table G). Several of the offers were dropped from further consideration for reasons described below, but the more important result was that no offers were found to be more economically attractive than the Company's NBA. At this point, with NCI having validated these results, PacifiCorp could have chosen to cease any further discussion with these counterparties and simply moved forward with its cost-based alternative at Currant Creek. Two intervening

[illegible] Bid Category [illegible] Round II

Bidder Name	Bid Number
Duke Energy North America	401
Wartsila	301
Wartsila	122
Spring Canyon Energy	135
Wartsila	263
Centennial Power/CEM	940
Colorado Energy Management	351
Encore Power Development	495
Duke Energy North America	[illegible]98
Duke Energy North America	877

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factors in this decision, however, were the fact that the super peak bid category offers did not look promising and that the Company had issued a revised load forecast indicating a load and resource imbalance in the Eastern portion of its system in 2005 that was projected to be nearly two times as large as what had been identified in the IRP. Building the peaker bid category NBA would not completely create a balance between projected loads and committed resources. Under the assumption that this revised load forecast was accurate, it was decided that a new NBA was needed for benchmarking purposes (since the Currant Creek peaker NBA was effectively not a future alternative any longer) and that the Company would go back to the top bidders – Duke, Wartsila, and Spring Canyon – to see whether or not another opportunity to revise their offers would result in something more economic relative to the next NBA. The smaller list of counterparties was driven by the interest in having a manageable number of companies with whom the Company potentially could engage in more detailed negotiations.

PacifiCorp then prepared another NBA, which NCI validated, before reviewing revised bids from these three companies. In short, the NBA consisted of forward market purchases for two years and an expansion at the Currant Creek site for the remaining eighteen-year period. This is what the revised Round III offers were benchmarked against (See Table H). Once PacifiCorp received these offers, summarized them and prepared revised economics, additional clarifying discussions were held with the bidders to ensure that the Company accurately modeled what the bidder was presenting. In addition, PacifiCorp provided feedback to the bidders about what terms and options would be most attractive to the Company. The bidders responded to this request by providing slight permutations of their offers including various terms and financing arrangements. The result of these discussions was the final ranking of offers relative to the NBA and was captured in the Round IV ranking summary (See Table I). Upon review of these best and final offers no offer was found to be economically superior to the NBA. Consequently, discussions with all bidders in this bid category were ceased.

The remainder of this section walks through each of the offers and the evolution of discussions with each of the bidders about their respective offers in each round. A brief description of the offer is provided first followed by a discussion of the primary issues that arose during the clarifying discussions with bidders regarding each of their offers..

Table H: Peaker Bid Category Short List – Round III

Bidder Name	Bid Number
Spring Canyon Energy	135
Wartsila	122-2
Wartsila	122-4
Wartsila	122-1
Wartsila	122-3
Duke Energy North America	401

Table I: Peaker Bid Category Short List – Round IV

Bidder Name	Bid Number
Spring Canyon Energy	135-Base
Spring Canyon Energy	135-Base+DF
Wartsila	122-5
Wartsila	122-2
Wartsila	122-4
Wartsila	122-1
Wartsila	122-3
Duke Energy North America	401-Moapa Equity
Duke Energy North America	401-20 yr
Duke Energy North American	401-10 yr
Duke Energy North America	401-5 yr

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SALT LAKE COUNTY

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IN THE THIRD DISTRICT COURT

SALT LAKE COUNTY, STATE OF UTAH

USA POWER, LLC; USA POWER PARTNERS, LLC; and SPRING CANYON ENERGY, LLC, Plaintiffs, vs PACIFICORP; JODY L. WILLIAMS and HOLME, ROBERTS & OWEN, LLP, Defendants.	**MEMORANDUM IN SUPPORT OF PACIFICORP'S MOTION FOR SUMMARY JUDGMENT** Civil No. 050903412 Judge Tyrone E. Medley

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that the Public Service Commission of Utah approved and oversaw the detailed process which resulted in PacifiCorp's decision to build Currant Creek   Never mind that the Public Service Commission of Utah's "Order Granting a Certificate of Convenience and Necessity" that allowed Currant Creek to be built, over USA Power's vigorous objections, was only issued after USA Power participated fully in the Public Service Commission hearings   Never mind   It sounds too absurd

Based on the undisputed facts, each of plaintiffs' claims fail as a matter of law because (1) none of plaintiffs' supposedly "misappropriated" information was secret and (2) PacifiCorp did not use any of plaintiffs' information in any event

<u>UNDISPUTED MATERIAL FACTS</u>

<u>Panda Energy</u>

1   In late 2000 and early 2001 a successful power plant developer from Texas, known as Panda Energy,[1] began its development of a combined cycle power plant site immediately adjacent to PacifiCorp's switching station near the town of Mona, in Juab County, Utah   The Deseret News reported Panda's plans in an article published July 19, 2001   Panda Energy's David Barlow Deposition taken September 6, 2006, at pp 28-35, 40-41, 51, 83-86, 92-102, attached hereto as Exhibit A   *See*, newspaper article about Panda produced by plaintiffs from their files, Bates Nos USA 7341-7342, attached as Exhibit "B", *see also*, Panda Monthly Report, dated October 2001, deposition exhibit 292, attached hereto as Exhibit "C "

[1] For a listing of Panda Energy s successful projects, see http /www pandaenergy com

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2 By the end of April 2001, Panda had secured options to purchase 240 acres of land next to PacifiCorp's Mona switching station The site was ideal for a combined cycle plant because of its immediate proximity to PacifiCorp's transmission system and high pressure natural gas transmission pipelines owned by Questar Pipeline Company ("Questar") and Kern River Gas Transmission Company ("Kern River") *See, id* , Barlow depo at pp 35, 135-138

3. In addition to acquiring land, Panda took the following steps to develop its power plant, among others

a. hired a market consultant (R W Beck) to prepare a report assessing the electric power market within the state of Utah,

b. hired environmental and air quality firms to prepare an Environmental Site Evaluation and Planning Report and erect an on-site meteorological/monitoring station to gather meteorological data to support Panda's application to the Utah Division of Air Quality for an air permit,

c. met with PacifiCorp's transmission group in Portland, Oregon, to arrange for an Interconnection Study at Panda's cost to provide an analysis of the cost of interconnecting Panda's power plant to PacifiCorp's transmission system at the Mona switching station,

d. hired a lobbyist to lobby state and local officials,

e. visited the Mona switching station with its engineers to design a transmission path from the power plant site to the switching station,

f. located the nearby Questar Mainline 104 and Kern River natural gas transmission pipelines using available maps and visible markers,

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g. mapped out two alternate routes to place lateral gas lines to transport natural gas from Questar's and Kern River's gas transmission pipelines, and,

h. hired a water lawyer to pursue the acquisition of water from at least three sources

Barlow depo at pp , 36-39, 42-67, 70-72, 74-77, 81-82, 90-91, 94-99, 118-119, 123-125, and 133-138, *see also*, deposition exhibits 284, 287, 292, 290, 291, 294, 295, 296, attached hereto as Exhibits D, E, C, F, G, H, I, and J, respectively

4 After all of these pieces of its power plant development were in place, Panda contacted PacifiCorp's Managing Director of Resource Development, Rand Thurgood, PhD [2], and set up a meeting in Salt Lake City, Utah Barlow depo at pp 102-116 Panda's hope at the time was that PacifiCorp would be interested in purchasing the power generated from Panda's power plant under a long term power purchase contract *See, Id*

5 The meeting between Panda and Rand Thurgood took place June 19, 2001, at PacifiCorp's offices at One Utah Center Panda, with its maps and engineering design drawings in hand, made a full blown, detailed presentation to Mr Thurgood, explaining the size, location and design of Panda's power plant Barlow depo at pp 69-70, 102-115

6 Panda explained the intended combustion technology of its plant based on Panda's standard plant design using General Electric 7FA gas turbines in a "2 on 1" (also

[2] Rand Thurgood holds a doctorate in chemical engineering from Brigham Young University His dissertation addressed power plant combustion Rand Thurgood deposition, taken January 19 20, 2006 (hereafter Thurgood depo ") attached hereto as Exhibit "K" at page 8 Mr Thurgood was formerly the director of power plant engineering for the whole PacifiCorp system *Id* at page 12 In June, 2004 he was promoted to Vice President of Resource Development and Construction *Id* at page 482

referred to as 2x1) configuration Panda explained how it was gathering a year's worth of meteorological data to support its application for an air permit It explained how the electricity from the power plant would flow over PacifiCorp's transmission system from an interconnect at the Mona switching station It explained how and where the natural gas would be transported to the plant from a new lateral pipeline connected to Questar's and Kern River's transmission pipelines along one of two routes that Panda had mapped out It explained how water could be acquired from Kennecott and piped to the plant And, it touted the positive attitude of local zoning officials to a proposed zoning change and the enthusiastic response that Panda had received from legislative and community leaders Barlow depo at pp 102-115, Rand Thurgood deposition, taken January 19-20, 2006 (hereafter "Thurgood depo "), at pp 115-135, attached hereto as Exhibit "K"

7. Although PacifiCorp did not have an interest in acquiring power from Panda's power plant under a long term contract, PacifiCorp did have an interest in acquiring the Panda project as a potential power plant site for PacifiCorp's electric generation system Barlow depo at pp 142-146, Thurgood depo at pp 137-141

8 PacifiCorp periodically published its Integrated Resource Plans outlining the anticipated needs for electric power generation throughout PacifiCorp's system As Managing Director of Asset Optimization (later as Director of Resource Development in 2001) Rand Thurgood had been given the task beginning in 2000, of assembling as many new resource (i e , power plant) options as he could so that PacifiCorp could select from among the best resources to serve its customers' increasing demand for electricity Thurgood depo at pp 26-28, 51-58, 67-68, 80 81

9 Mr Thurgood considered all available resource options, not just Panda He met with Mirant Corporation ("Mirant") as early as 2001 about a possible equity interest in Mirant's Apex 1 combined cycle power plant in Las Vegas In June 2002, while it was still under construction, Mr Thurgood visited the Apex 1 plant and he and his team of PacifiCorp engineers investigated Apex 1's combined cycle equipment, plant layout and design Thurgood depo at pp 99-103 While nothing further came of Mr Thurgood's discussions with Mirant, his discussions with Panda were in the same vein, i e , to assemble as many options for PacifiCorp as he could for possible new generation resources Thurgood depo at pp 99-109, 397, 465-466

10 Mr Thurgood spoke with Panda several times between June 2001 and July 2002, inquiring each time whether Panda would sell its project to PacifiCorp Panda consistently rebuffed Mr Thurgood's inquiries until finally, on July 31, 2002, Panda communicated to Mr Thurgood that Panda would entertain selling its project to PacifiCorp Barlow depo at pp 78, 142-153, 229-230, Thurgood depo at pp 137-141

11 Negotiations and due diligence followed, and on February 20, 2003, PacifiCorp acquired Panda's project for approximately $1 0 million *Id* , Barlow depo at pp 77-80, 142-147 154-158 PacifiCorp acquired the following Panda assets (a) Option Agreements and Purchase Contracts to purchase 240 acres of land, (b) Environmental Site Evaluation and Planning Report, (c) Ground Water Study Feasibility Screening Study Report, (d) Meteorological and Air Quality Monitoring Quality Assurance Plan and (e) Dispersion Modeling Protocol -approved by Utah Division of Environmental Quality, (f) Air Quality PSD Monitoring

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Protocol, (g) 1-year Audited Meteorological data from plant site property, (h) Meteorological Tower and associated equipment, (i) Market Study from R W Beck, (j) Transmission Study from R W Beck and (k) PacifiCorp Interconnect Study Report Barlow depo at pp 156-157, Thurgood depo at pp 138-140, *See*, deposition exhibits 301 and 302, attached hereto as Exhibits L and M, respectively

<u>Spring Canyon Energy</u>

12 In February 2002, plaintiff Spring Canyon Energy filed a Notice of Intent (NOI) with the Utah Department of Environmental Quality, Division of Air Quality, seeking an air permit for a combined cycle power plant to be located on a 40 acre parcel located ½ mile north of the Panda plant site The NOI immediately became a public document Ted Banasiewicz deposition, taken March 6-9, 2006, at pp 803, 814-816, 821-826, attached hereto as Exhibit N, *see*, Affidavit of Ian Andrews, including the NOI attached thereto, filed concurrently herewith, *see also*, Utah Division of Air Quality file for Spring Canyon Energy marked as deposition exhibit 168, attached hereto as Exhibit O, at Bates No UDAQ0108, UDAQ0110, UDAQ0115-0117, UDAQ0147-0175

13 Spring Canyon's NOI not only identified the location of Spring Canyon's plant site, it laid out many of the details of the proposed plant For instance, it identified the plant's combustion technology based on General Electric 7FA gas turbines, and it confirmed that the Spring Canyon plant would have heat recovery steam generators equipped with selective catalytic reduction systems, supplemental duct firing and a steam turbine generator The NOI explained that the proposed plant would take natural gas from the two high pressure natural gas

transmission sources in the area, meaning the Questar Mainline 104 and Kern River transmission pipelines, and that the proposed plant would interconnect to PacifiCorp's transmission system at the Mona switching station The NOI identified the manufacturer of the proposed plants' pollution control equipment, the heat input rate for the gas turbine and the duct burners, and the expected capacities of the gas turbine generator and the steam turbine generator According to Spring Canyon's public filing, Spring Canyon selected an air cooled condenser to air cool, rather than wet cool, the condensed steam from its plant, because an air cooled condenser uses less water *See*, Ian Andrews Affidavit and the NOI attached thereto, Ted Banasiewicz depo at pp 800-813

14 As part of the air permitting process, a notice of Spring Canyon's application for an air permit was published in the Nephi Times on October 16, 2002 Like the NOI, the published notice laid out many of the details of the project concept *See*, newspaper notice in deposition exhibit 168 (Exhibit O hereto) at Bates No UDAQ0032-0034, Ted Banasiewicz depo at pp 812-814

15 The NOI ultimately culminated in the issuance of an Approval Order (i e , air permit) to Spring Canyon from the Executive Secretary of the Utah Air Quality Board on November 27, 2002 Like the NOI and the newspaper notice, the publicly available Approval Order laid out many of the details of the proposed Spring Canyon plant *See*, Approval Order attached to Ian Andrews Affidavit, *See also*, deposition exhibit 168 (Exhibit O hereto) at Bates No UDAQ001-0018

16 The first meeting between PacifiCorp and USA Power occurred on August 22, 2002 This first meeting occurred (a) more than a year after Panda made its detailed presentation

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to PacifiCorp, (b) two months after Mr. Thurgood had toured the Apex 1 plant in Las Vegas, and (c) three weeks after Panda had told PacifiCorp that Panda would consider selling its Mona project assets. Ted Banasiewicz depo. at pp. 155-156; *See*, Undisputed Facts ¶¶ 5, 9-10, above.

17. A week prior to the August 22, 2002 meeting, PacifiCorp's Ian Andrews requested and immediately received a faxed copy of Spring Canyon's NOI from the Division of Air Quality. He immediately e-mailed Rand Thurgood outlining details of the NOI. Ian Andrews Aff. at ¶¶ 3-4, including e-mail dated August 15, 2002 (Bates No. 31456) attached thereto; Ian Andrews deposition taken February 15, 2006 at pp. 79-82, attached hereto as Exhibit P.

18. USA Power met with PacifiCorp a second time on September 11, 2002. At the beginning of the meeting Mr. Thurgood signed a Confidentiality and Non-Disclosure Agreement with USA Power Partners, LLC. Thurgood depo. at pp. 288-289; Confidentiality and Non-Disclosure Agreement, deposition exhibit 9, attached hereto as Exhibit Q.

19. On August 21, 2002, the day before their first meeting with PacifiCorp, the USA Power principals met with Tom Florence of Utah Associated Municipal Power System (UAMPS) in Salt Lake City, Utah. They handed Mr. Florence a copy of the same volume of information that they later gave to PacifiCorp. Mr. Florence and UAMPS did not sign a confidentiality agreement. *See*, Affidavit of Tom Florence, filed concurrently herewith.

<u>Currant Creek Power Plant</u>

20. PacifiCorp utilized the project assets that Panda had started assembling in late 2000 and early 2001, including land options and purchase contracts, environmental studies, and

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most significantly a year's worth of meteorological data, to apply for and obtain an air permit and construct the Currant Creek power plant on the Panda site Thurgood depo at pp 111-112, 124-125, 163-164, Bob Van Engelenhoven deposition, taken September 29, 2006, at pp 74-75, attached hereto as Exhibit R, Ian Andrews depo at pp 160-161

21 Currant Creek was designed, engineered and constructed for PacifiCorp by Shaw/Stone & Webster, which designed, engineered and constructed the Apex 1 plant for Mirant Corporation in Las Vegas, Nevada Apex 1 was completed in 2003 Affidavit of Mark Green filed concurrently herewith at ¶ 5

22 Like the Apex 1 plant and many other combined cycle plants, Currant Creek is a 2x1 combined cycle design, meaning it has two natural gas turbine generators and a single steam turbine generator Currant Creek and Apex 1 were both designed and engineered based on Shaw/Stone & Webster's standard plant design for a 2x1 combined cycle power plant with air cooling Currant Creek, like Apex 1, is based on a recognized and proven 2x1 combined cycle configuration that is well understood and widely utilized in the electric power plant industry *Id* at ¶ 8

23 Although there are minor differences in output rating between Apex 1 and Currant Creek,[3] the plants are essentially sisters Both plants utilize two General Electric 7FA7241 gas turbines with almost identical nominal ratings, both plants have two similarly sized heat recovery steam generators equipped with selective catalytic reduction systems, both plants have a single similarly sized steam turbine generator, both plants have duct firing with similar capability, both

[3] The minor differences are due primarily to differences in elevation, and higher expected temperatures and the use of steam injection at Apex 1

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plants are 100% dry (air) cooled, and both plants are designed for zero wastewater discharge *Id* at ¶ 7

24 In 2002, a combined cycle plant in a 2x1 configuration was not a secret A combined cycle plant with General Electric 7FA gas turbines was not a secret A combined cycle plant with heat recovery steam generators was not a secret A combined cycle plant with additional duct burner capacity was not a secret, a combined cycle plant with a steam turbine generator was not a secret A combined cycle plant with air cooling was not a secret A combined cycle plant designed for zero wastewater discharge was not a secret All of these features of a combined cycle power plant were openly used in the electric generation industry well before 2002 *Id* at ¶ 8

25 At PacifiCorp's request, Shaw/Stone & Webster assembled a detailed project cost analysis for Currant Creek, which was a second-level design (i e , beyond the conceptual or preliminary design), so that PacifiCorp would have available a cost estimate that was worthy of consideration for budgetary purposes and in a Public Service Commission process Shaw/Stone & Webster's employees began their work on the project cost analysis in late April 2003 and submitted the project cost analysis to PacifiCorp in a large binder on or about June 9, 2003 Completing this work during the period from late April to early June was not unusual for Shaw/Stone & Webster The detailed project cost analysis utilized Shaw/Stone & Webster's in-house databases and reference plant designs, and was a normal part of Shaw/Stone & Webster's regular business designing and engineering combined cycle power plants like Currant Creek, Apex 1, and other combined cycle plants in the United States and around the world *Id* at ¶¶ 9, 11, Thurgood depo at p 182

26 PacifiCorp used Shaw/Stone & Webster's project cost analysis, plus operational and maintenance information that was furnished by General Electric, as well as operational and maintenance studies that PacifiCorp had already performed on its gas fired Gadsby plant, and manpower requirements that PacifiCorp developed from its Hermiston combined cycle plant in Oregon, and put this information together with financial information compiled by its financial analyst, to form its Currant Creek project *See*, Ian Andrews depo at pp 227-231

27 Currant Creek is located adjacent to the Mona switching station, where Currant Creek interconnects to PacifiCorp's transmission system The Mona switching station is connected to three transmission lines that are operated at 345 kV and run north and south along the eastern edge of the Oquirrh Mountains through Juab County Green Aff at ¶ 4, *see also CH2MHill Critical Issues Analysis Mona Site*, deposition exhibit 363 at Bates No PAC004986, attached hereto as Exhibit S

28 The route of the 20" lateral gas line to bring natural gas to Currant Creek from Questar's Mainline 104 gas transmission pipeline was designed by Questar Pipeline Company Questar not only designed the route of the lateral line, it performed the environmental work, obtained the necessary permits and rights of way, did all of the necessary engineering, and hired a contractor to construct the lateral line Questar paid for all of the costs and maintains ownership of the lateral line PacifiCorp has entered into long term contracts to re pay Questar for the lateral line over time Deposition of Lynn Arnold, taken on September 28, 2006 at pp 4-6, 18-21, 24, 26, 31-32, attached hereto as Exhibit T

29 The design, engineering and construction of Currant Creek represents Shaw/Stone & Webster's own efforts Shaw/Stone & Webster did not use any information from, or about,

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USA Power, USA Power Partners, Spnng Canyon Energy, or the Spnng Canyon Energy project,

ın <u>any</u> aspect of the Currant Creek power plant, whatsoever Green Aff at ¶ 14

<u>ARGUMENT</u>

I. SUMMARY JUDGMENT IS APPROPRIATE WHEN THERE ARE NO GENUINE ISSUES OF MATERIAL FACT AND THE MOVANT IS ENTITLED TO JUDGMENT AS A MATTER OF LAW

Summary judgment ıs appropnate upon a showıng "that there ıs no genuıne ıssue as to any matenal fact and that the movıng party ıs entıtled to a judgment as a matter of law " Utah R Cıv P 56(c), *see also, e g*, *Kearns-Trıbune Corp v Salt Lake County Comm'n,* 2001 UT 55, ¶ 7, 28 P 3d 686 The movıng party has the burden of presentıng evıdence to demonstrate that no genuıne ıssue of matenal facts exısts and that judgment as a matter of law ıs proper Utah R Cıv P 56(e) However, once the movıng party challenges an element of the nonmovıng party's case on the basıs that no genuıne ıssue of matenal fact exısts, the burden then shıfts to the nonmovıng party to present evıdence that ıs suffıcıent to establısh a genuıne ıssue of matenal fact Utah R Cıv P 56(e), *Orvıs v Johnson*, 2006 UT App 394, ¶¶ 11,16, fn 7, 146 P 3d 886, *Shaw Resources, Ltd L L C v Pruıtt, Gushee & Bachtell, P C* , 2006 UT App 313, 142 P 3d 560, *Waddoups v Amalgamated Sugar Co* , 2002 UT 69, 54 P 3d 1054 (Utah 2002) The nonmovıng party "may not rest upon the mere allegatıons or denıals of hıs pleadıng, but hıs response, by affidavıts or as otherwıse provıded ın thıs rule, must set forth specıfic facts showıng that there ıs a genuıne ıssue for tnal " Utah R Cıv P 56(e), *see e g*, *Grand County,* 2002 UT 25 at ¶ 21, 44 P 3d 734 The nonmovıng party must submıt more than just conclusory assertıons that an ıssue of materıal fact exısts to establısh a genuıne ıssue *Orvıs v Johnson*, supra at ¶ 11

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But the reason PacifiCorp is entitled to summary judgment is much more simple than this equitable principle. To establish an unjust enrichment cause of action, plaintiffs must meet three elements: First, there must be a benefit conferred on one person by another. Second, the conferee must appreciate or have knowledge of the benefit. Finally, there must be the acceptance or retention by the conferee of the benefit under such circumstances as to make it inequitable for the conferee to retain the benefit without payment of its value. *Bluffdale City v. Smith,* 2007 WL 270422, 2007 UT App ___.

Summary judgment should be granted for PacifiCorp on the unjust enrichment claim because there are not facts in the record- and a reasonable juror could not find - that PacifiCorp made any use of plaintiffs' "Confidential Information." Thus, there could not possibly be any benefit conferred on PacifiCorp in satisfaction of the first element. Accordingly, there is no reason to analyze the additional elements further; plaintiffs cannot sustain a claim for unjust enrichment as a matter of law. PacifiCorp is entitled to summary judgment on this point as well.

CONCLUSION

For the reasons set forth, PacifiCorp's Motion for Summary Judgment should be granted.

Dated this 30th day of April, 2007.

P. Bruce Badger

P. Bruce Badger
FABIAN & CLENDENIN
a professional corporation
Attorneys for Defendant PacifiCorp

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COPY OF TRANSCRIPT

IN THE THIRD JUDICIAL DISTRICT COURT

SALT LAKE COUNTY, STATE OF UTAH

USA POWER, LLC; USA POWER PARTNERS, LLC; and SPRING CANYON ENERGY, LLC,	)	Deposition of:
	)	**DAVID J. BARLOW**
Plaintiffs,	)	
vs.	)	No. 050903412
PACIFICORP; JODY L. WILLIAMS and HOLME, ROBERTS & OWEN, LLP,	)	Judge Medley
Defendants.	)	

September 6, 2006 * 9:05 a.m.

Location: Fabian & Clendenin
215 South State Street, 12th Floor
Salt Lake City, Utah 84111

Reporter: Lisa D'Elia, CSR, RPR
Notary Public in and for the State of Utah

81 of [illegible]

on the community and all of this, and we asked him to keep it very confidential because this is just one of several sites that we were looking at. He was very helpful in telling us who all we might need to talk to. So we at some point told him that, yes, we were looking at building a power project. Of course, I gave him my business card on one of these occasions and it was pretty evident what business we were in.

Q. Do you know when you would have met with him?

A. That would have been in the 2000...

Q. Time frame?

A. Yes.

Q. By that time, did you have a vision of what kind of a plant you wanted to propose for Mona?

A. Definitely.

Q. What kind of a plant did you want to propose?

MS. TOMSIC: Bruce, are you saying him personally or Panda?

Q. (By Mr. Badger) You understand my question, don't you?

A. Yes.

Q. Go ahead.

A. Panda had a standard footprint for a plant like we developed in Texas. One of the reasons that we were so effective in coming up with the engineering for these things is we stuck with a single model and didn't vary from it too much except where it was necessary for the -- for where the facility was located. A lot of that was driven by what water was available. We always preferred water-cooled condensers.

Q. When you say "we," you mean Panda?

A. Panda. And some places we needed well water. Other places, if we had access to other water, then we would do that. And during this same time that I was talking to the city dads, I was making a tour of all of the different resources for water that I saw out here in Utah and I --

Q. Go back to tell me what kind of a plant you envisioned.

A. Oh, yeah. Well, our typical plant was a thousand megawatt or larger facility, 2-on-1. We used the GE7FA technology. We had an order in for a number of turbines with GE on these, and kind of -- as a company, Panda would go and they would negotiate delivery of these turbines and, as you may be aware, there were hundreds of companies all trying to reserve manufacturing time slots, and timing, when

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you were goıng to be able to take delıvery of these, along wıth actually developıng the project was kınd of an art, and Panda was excellent at that Of course, where we had a number of turbınes that we had scheduled, one of the other thıngs that we dıd ıs we talked to other companıes that had projects that they were developıng and ıf they ran ınto problems and they had some of these turbınes reserved, then we would negotıate some sort of purchase of these -- theır slots for thıs GE dıdn't lıke people doıng that They wanted to control all of that process themselves and, of course, take all the profıt that they possıbly could out of that

Q. Well, by the tıme you met wıth Glen Greenhalgh, by that tıme dıd you already have ın mınd a combıned-cycle combustıon turbıne plant?

A. Yes

Q. For Mona?

A. Yes Towards doıng that, you know, I started talkıng to a number of sources for water Strawberry Water Users was one of them, the CUP, the Conservancy Dıstrıct, and --

Q. Were you thınkıng of an aır-cooled or a water-cooled plant at that poınt?

MS. TOMSIC I'm goıng to object to the

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question on the grounds that you are not letting him finish his answers before you ask the next question, and I just think it is important for the record that you make sure he's concluded his answer before you ask your next question.

Q. (By Mr. Badger) Were you thinking of a water-cooled or air-cooled design at that point?

A. It was water-cooled. We did some in-house analyses for air-cooled. We had some people in-house that -- one fellow that had worked for PacifiCorp and developed an air-cooled facility up in someplace, I can't recall, but --

Q. WYODAK?

A. I believe so. A coal-fired facility. And he was very good with this stuff. He actually headed up some of our engineering group at that time. We did some analyses and we determined, you know, that the air-cooled was just going to be too expensive. We ended up -- you know, of course, I was searching for water for this thing and Panda let me know that that was the way that I should probably go, just because to keep the cost of operating this facility within something that the power was a good price and we could make some money on it. So I continued to talk to a number of these different options. There

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was a mine, the Burgin Mine, that wasn't too far from that site. We talked to them about getting water. Their water was filling up this mine and they were mining salt out of that, among other things, and this water was something that they just didn't need. They needed a place to send that. The complication we found with that was that there were some groups that had water rights in Utah Lake that said that this water was actually coming from Utah Lake, and they had a geological analysis to support their side, the Burgin Mine said, no, it was different, the quality of the water was different, yada, yada, yada. And so -- but since that was all tied up, we went actually to the state and tried to get a feel from people at the state that were going to be making a determination on whose water it actually was to see what they were probably going to rule.

We continued to search for other sources of water, including looking at well water. We had some studies done to see what would be possible down there. One of the problems we found with the well water is that it was considered ag water and we would need basically twice as much rights to twice as much water as we actually were going to use for the facility to allow for it to replenish the aquifer in

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IN THE THIRD JUDICIAL DISTRICT COURT

OF SALT LAKE COUNTY, STATE OF UTAH

USA POWER, LLC; USA POWER PARTNERS, LLC; and SPRING CANYON ENERGY, LLC, Plaintiffs, vs. PACIFICORP, JODY L. WILLIAMS and HOLME, ROBERTS & OWEN, LLP, Defendants.	)	30(b)(6) Examination: **RAND THURGOOD** Civil No. 050903412 Judge Tyrone E. Medley

September 28 , 2006 * 9:30 a.m.

Location: TOMSIC & PECK
Attorneys at Law
136 East South Temple, Suite 800
Salt Lake City, Utah 84111

Reporter: LANETTE SHINDURLING, RPR, CRR
Notary Public in and for the State of Utah

believe we were given permission to do so.

Q. Okay. And once you all received that permission, did you actually obtain the water or what happened with that?

A. No. Up and to that point we had been talking to Geneva. If you go back into the Panda records, you'll see that they had talked to Kennecott and Geneva for procurement of water. We had used their initial preliminary design in looking at a wet-cooled plant at that site and had hoped that we could achieve it.

What Panda had basically proposed was to purchase water out of Utah Lake and to pipe it to the site. And at this time we had Hansen, Allen & Luce working on what it would cost to pipe that water to the site. We did not have an answer as to that yet. And we had hoped that we would be able to talk with Geneva, if not Kennecott, to get the water. And that's what this was all about.

Q. Okay. What happened with that effort to pipe the water from Utah Lake?

A. Hansen, Allen & Luce determined that the cost of that pipeline was going to be very expensive. It was, I'm trying to remember, it was some 20-odd miles at a cost of over a million dollars a mile, and

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that it would be very difficult to do because of the area that you had to go through to get right-of-way. And it was at that point we started to wonder whether this was really going to be a viable option for us to have a water-cooled plant.

We also ran into problems with Geneva. In purchasing the water, they were very, very slow, they had bankruptcy proceedings to go through, and we were just basically going nowhere.

Q. The Geneva water, would that also have been piped from a remote location?

A. Yes.

Q. Where?

A. Utah Lake.

Q. Okay. So basically whoever the seller was, it would have been piped in from Utah Lake?

A. Correct. So it was at that point in time that we realized that the expectation of Panda was just not economically realistic.

Q. And when did you come to this realization?

A. I don't recall the exact time frame. I do recall that we determined to go to an air-cooled project in about the middle of May. So we were evaluating these things with Stone & Webster and with Hansen, Allen & Luce and with Jody Williams in terms of how much water we could acquire, and that was all just coming to a head in the May time frame.

Q. Other than what you've testified to, and you've already testified as to the Geneva and the Kennecott situation, was there any other reason that you -- well, strike that. Let me rephrase it.

Did there come a time that you actually switched from wet to dry cooling for the Mona Power Plant?

A. I think, as I've said, it was in May.

Q. And what was the reason for that switch?

A. Just the accumulation of all of the answers that we had been seeking.

Q. When you switched from wet to dry, what did that mean for the future of the project on the site?

A. It meant that we would have to expend a little bit more capital to purchase the water. Excuse me, an air-cooled facility. We would also have the advantage of not having to build the pipeline for large amounts of water. We could procure about 10 percent of the amount of water that would be needed for a water-cooled plant. So there were both positive and negative implications of that decision.

record. Mr. Thurgood, I'm going to hand you what is marked as 371 and ask if you can identify that document?

A. It is an e-mail from Ian Andrews to Steve Rottinghaus of Burns & McDonnell with respect to wet versus dry at Mona dated May 7, 2003.

Q. Okay. And you had talked earlier about some work that had been done by Burns & Mac, I think you called it, on the project?

A. Yes.

Q. Does this refresh your recollection as to what work Burns & Mac did?

A. Well, it refreshes my memory in that we asked them to do something. I had not gotten into the specifics of what they were trying to -- were being asked to do by Ian.

Q. Okay. What was your recollection of what they had been asked to do?

A. To give us an independent evaluation of the project position at that site on wet versus dry and what the differences would be.

Q. And I don't know if we actually have these performance numbers. I notice if you go down it talks about various configurations. Do you see that?

A. Yes.

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Q. And then it talks about the Provo weather data. Do you see that?
A. Yes.
Q. Any reason why you used Provo?
A. It's data that's close to the site and readily available.
Q. Had you all done the net capacity and heat rate runs at this point?
A. In general terms, as I've talked about in prior testimony before, yes.
Q. Had you done it using -- what weather data had you all used?
A. I do not know which data they used.
Q. Did you all pay Burns & Mac to do this?
A. Yes.
Q. Do you see where it says below the Provo weather data, "I have attached Wayne Micheletti's article on wet versus dry cooling"?
A. Yes.
Q. "For your information as well as an estimate of degradation of simple/combined-cycle frame machines"; do you see that?
A. Yes.
Q. Do you understand what Burns & Mac was trying to do was actually to get at the efficiency

loss?

A. To get at the cost differences vis-a-vis the efficiency and losses of wet versus dry, yes.

Q. Going back up to the top where it says, "Here is to confirm what we're looking for," it says "Equations" and then it has in parentheses, "2nd order" with a question mark. Do you know what that referred to?

A. There are a number of general equations that can be used and then there are other equations that hopefully get to more specificity. And I think that's what it's referring to, but I couldn't answer that for a fact.

Q. Do you know when Burns & Mac actually did this performance testing for you?

A. Not specifically. I do know that we concluded our decisions in mid May on whether it would be wet versus dry. So it was a very cursory study done very quickly, so a week or two's time frame.

(EXHIBIT-372 MARKED.)

Q. (BY MR. PETERSEN) All righty. I hand you what is 372 and once again ask if you can identify this document?

A. An e-mail from Ian Andrews to Jim Lacey

COPY OF TRANSCRIPT

IN THE THIRD JUDICIAL DISTRICT COURT

OF SALT LAKE COUNTY, STATE OF UTAH

USA POWER, LLC; USA POWER PARTNERS, LLC; and SPRING CANYON ENERGY, LLC,	Deposition of:
Plaintiffs,	THEODORE BANASIEWICZ
vs.	VOLUME IV
PACIFICORP, JODY L. WILLIAMS and HOLME, ROBERTS & OWEN, LLP,	Civil No. 050903412
Defendants.	Judge Tyrone E. Medley

March 9, 2006 * 9:31 a.m.

Location: SUROVELL, MARKLE, ISAACS & LEVY
Attorneys at Law
4010 University Drive, Suite 200
Fairfax, Virginia 22030

Videographer: David Voitsberger
Reporter: LANETTE SHINDURLING, RPR, CRR
Notary Public in and for the State of Utah

9217

air-cooled condenser?

A. Correct.

Q. And that's referred to sometimes as dry cooling; would you agree?

A. I would.

Q. And an air-cooled condenser is really like a radiator in an automobile; would you agree?

A. I would.

Q. The steam goes through tubing and it's surrounded by fins just like a radiator in a car. And just like a radiator in a car that has a fan blowing the air over the radiator, an air-cooled condenser has that configuration with tubing, fins and fans; would you agree?

A. I would agree.

Q. Spring Canyon -- let me -- strike that. If it's water cooled it has cooling towers; true?

A. True.

Q. And would you agree with me that a water-cooled plant, all other things being equal, the same plant water cooled versus dry cooled, the water cooled takes more water for the plant?

A. I would agree.

Q. In fact, it takes considerably more than an air-cooled plant; would you agree?

9243

A. I would agree.
Q. Spring Canyon determined that it would go with an air-cooled condenser for the Spring Canyon Energy Project because of the scarcity of water in the Mona area; true?
A. I believe that's an oversimplification of the answer.
Q. Well, you testified that Mona is arid?
A. It is. The answer to your question is that the ideal situation would not be to use dry cooling. The ideal situation is to find a site that has access to sufficient water resources so that you could use the much more traditional wet-cooled facility. There are many power plants that are in arid areas that utilize wet cooling.

The analysis that was performed by our consultants and by Ms. Williams identified that there is enough water in the Juab Valley to utilize wet cooling. A small firm such as ours did not have the time nor the financial resources to go out and acquire all of that at risk during the development of a project. A larger corporation would have those financial resources and if it had taken the time to acquire those resources could very well have used a wet-cooled facility.

9744

Q. You testified --
A. So I think that -- is that a complete answer to your question?
Q. Yeah. But I don't think you've completely summarized what you testified about the other day. So let me see if I can help you. You said that in addition to the fact that you couldn't afford all of the water, you were too small and didn't have the money to do it, that the other consideration was that it would dry up Mona and would affect agricultural events?
A. It would.
Q. And that was all part of Spring Canyon Energy's consideration of going with air cooled; would you agree?
A. It's part of the answer, yes.
Q. In your view that was a rational justified business decision, was it not?
A. Yes.
Q. If PacifiCorp decided to go with air cooled because Mona is arid and to take all of the water would have an impact on the farmers in Mona, that would be a rational, legitimate business decision, don't you agree?
A. It would be.

9245

CONDENSED TRANSCRIPT

IN THE THIRD JUDICIAL DISTRICT COURT

SALT LAKE COUNTY, STATE OF UTAH

USA POWER, LLC; USA POWER PARTNERS, LLC; and SPRING CANYON ENERGY, LLC,	Deposition of:
	Lois Banasiewicz
Plaintiffs,	Volume I
vs.	
	Civil No. 050903412
PACIFICORP, JODY L WILLIAMS and HOLME ROBERTS & OWEN, LLP,	Hon. Tyrone E. Medley
Defendants.	

CONTAINS CONFIDENTIAL INFORMATION PURSUANT TO CONFIDENTIALITY AGREEMENT

August 1, 2006 * 9:19 a.m.

Location: Anderson & Karrenberg
50 West Broadway, Suite 700
Salt Lake City, Utah

Reporter: Susette M. Snider, CSR, RPR, CRR
Notary Public in and for the State of Utah

EXHIBIT
C
9763

understand it. Take your time and look this over.
MS. TOMSIC: There's something attached.
THE WITNESS: Oh, there is attached? Is it the file that's attached?
MS. TOMSIC: It's -- it is what it is, but that's what's attached. Just look at the whole document.
(A discussion was held off the record.)
THE WITNESS: Okay. I've read this, Mr. Call.
Q. (By Mr. Call) And this --
A. I just want to identify it. It's the chronology of actions to acquire water sources for the Current Creek project starting March 2003.
Q. Right. And this --
A. And ending February 2004.
Q. This purports to be actions undertaken by PacifiCorp to acquire water, doesn't it?
A. It does.
Q. And there is no mention of the price paid or the price that -- excuse me -- that you folks agreed to pay either Mr Keyte or Mr. Garrett for water in this memo, is there?
MS. TOMSIC: Object to the question on the grounds the document speaks for itself and is the

best evidence.
THE WITNESS: No, but it does speak to the phone call based on the information Michael Keyte talked to Ted Banasiewicz, PacifiCorp offering to buy water and enter in a purchase agreement with two individuals in Juab County.
Q. (By Mr. Call) And is that what leads you to believe that confidential information may have been disclosed?
A. Confidential information was disclosed. Whether it was PacifiCorp or whether it was Jody Williams, it was disclosed. You don't start out with $4,000 an acre-foot, what took us months to reach on that price.
MR. CALL Move to strike as nonresponsive.
Q (By Mr. Call) There's no reference to $4,000 an acre-foot put in this memo, is there?
MS. TOMSIC. Objection on the grounds it's argumentative, been asked and answered, on the grounds the document speaks for itself and is the best evidence of what the document contains
THE WITNESS This is a memo to Rand Thurgood regarding --
MS TOMSIC Lois, you need to listen to

his question and answer it.
THE WITNESS. Okay.
Q. (By Mr Call) There's no reference to $4,000 an acre-foot in this memo, is there?
A. Not on this memo, no, sir.
Q. Do you know where PacifiCorp obtained its water?
A. Just based on this --
MS. TOMSIC: Are you saying for the Current Creek Plant?
MR. CALL: Yes. Thank you.
THE WITNESS Um-hum. This memo is referencing the WW Ranch, LLC.
Q. (By Mr. Call) And do you know what the source of the water rights that WW Ranches was selling to PacifiCorp is? I'm not asking for you to find it in the document.
A. Oh, it's not in the document? Okay.
Q. I'm just asking you whether you know what the geographic source of the water rights that WW Ranches sold to Pacific were?
A. I know it was maybe 20, 30, 40 miles from the actual Current Creek.
Q They didn't originate in Juab County, did they?

A. No, it did not.
Q. And PacifiCorp didn't buy any water for the Current Creek plant from anyone that you folks had contacted with respect to selling -- potentially selling water to you, did they?
A. No, they did not.
Q Well, Mrs. Banasiewicz --
A. Yes.
Q. -- I think at this time I don't have any further questions
A. Okay.
MR BADGER: But I do. Should I get going?
MR. CALL· It's up to you folks
(A discussion was held off the record)
EXAMINATION
BY MR. BADGER:
Q. While we're on the topic of this telephone call from Michael Keyte to your husband --
A. Um-hum.
Q -- tell me who at PacifiCorp made an offer to someone in Juab County to buy their water for $4,000 an acre-foot
A. I don't know who made that particular offer.

CONFIDENTIAL

USA Power Partners LLC

Supplemental Due Diligence Information
To
Preliminary Offering Memorandum

Volume 2

Spring Canyon Energy LLC

450 Mw Natural Gas Fired,
Combined-Cycle Power Facility,
With Duct-Firing Capability for an
Additional 80 MW

Located in Juab County, Utah
With interconnection to the Western US RTO
Via the Mona (PacifiCorp) Substation

September 2002

Supplemental Due Diligence Information
To
Preliminary Offering Memorandum
Volume 2

Table of Contents

REALTOR®

REAL ESTATE PURCHASE CONTRACT

is is a legally binding contract Utah law requires real estate licensees to use this form Buyer and Seller however may agree to alter or delete its ions or to use a different form If you desire legal or tax advice consult your attorney or tax advisor

EARNEST MONEY RECEIPT

Buyer USA Power Partners LLC offers to purchase the Property described below and hereby delivers to the Brokerage, as Earnest Money, the amount of ~~$5,000.00~~ $7500.00 in the form of check which, upon Acceptance of this offer by all parties (as defined in Section 23), shall be deposited in accordance with state law

Received by Jody L Williams on 12-19-01 (Date)
(Signature of ~~agent/broker~~ Attorney acknowledges receipt of Earnest Money)!
Law Firm ~~Brokerage~~ Kruse, Landa & Maycock Phone Number (801) 531-7090

OFFER TO PURCHASE

1 PROPERTY Property description shown in Addendum "A"

also described as ______
City of ______, County of Juab, State of Utah, Zip 84645 (the "Property")

1 1 Included items Unless excluded herein, this sale includes the following items if presently attached to the Property plumbing, heating, air conditioning fixtures and equipment, ceiling fans, water heater, built-in appliances, light fixtures and bulbs, bathroom fixtures, curtains, draperies and rods, window and door screens, storm doors and windows, window blinds, awnings, installed television antenna, satellite dishes and system, permanently affixed carpets, automatic garage door opener and accompanying transmitter(s), fencing, and trees and shrubs The following items shall also be included in this sale and conveyed under separate Bill of Sale with warranties as to title N/A

1 2 Excluded items The following items are excluded from this sale N/A

3 Water Rights The following water rights are included in this sale none

1 4 Survey (Check applicable boxes) A survey [X] WILL [ ] WILL NOT be prepared by a licensed surveyor The Survey Work will be [ ] Property corners staked [ ] Boundary Survey [ ] Boundary & Improvements survey [ ] Other (specify) Alta Responsibility for payment X] Buyer [ ] Seller [ ] Buyer and Seller share equally Buyer's obligation to purchase under this Contract [ ] IS [X] IS NOT conditioned upon Buyer's approval of the Survey Work If yes, the terms of the attached Survey Addendum apply

2 PURCHASE PRICE The Purchase Price for the Property is $ Two Hundred Thousand Dollars ($200,000)

2 1 Method of Payment The Purchase Price will be paid as follows

$ 7,500.00 (a) Earnest Money Deposit Under certain conditions described in this Contract, THIS DEPOSIT MAY BECOME TOTALLY NON REFUNDABLE

$ ______ (b) New Loan Buyer agrees to apply for a new loan as provided in Section 2 3 Buyer will apply for one or more of the following loans [ ] CONVENTIONAL [ ] FHA [ ] VA
[ ] OTHER (specify) ______
If an FHA/VA loan applies, see attached FHA/VA Loan Addendum
If the loan is to include any particular terms, then check below and give details
[ ] SPECIFIC LOAN TERMS ______

$ ______ (c) Loan Assumption (see attached Assumption Addendum if applicable)
$ ______ (d) Seller Financing (see attached Seller Financing Addendum if applicable)
$ ______ (e) Other (specify) ______
192,500.00 (f) Balance of Purchase Price in Cash at Settlement

$ 200,000 00 PURCHASE PRICE Total of lines (a) through (f)

 Seller s Initials TMK Date 1-4-02 Buyer s Initials TB Date 1/4/02 PT75

9850

2 2 Financing Condition. (check applicable box)

(a) [ ] Buyer's obligation to purchase the Property IS conditioned upon Buyer qualifying for the applicable loan(s) referenced in Section 2 1(b) or (c) (the "Loan") This condition is referred to as the "Financing Condition "

(b) [X] Buyer's obligation to purchase the Property IS NOT conditioned upon Buyer qualifying for a loan Section 2 3 does not apply

2 3 Application for Loan

(a) Buyer's duties No later than the Application Deadline referenced in Section 24(a), Buyer shall apply for the Loan "Loan Application" occurs only when Buyer has (i) completed, signed, and delivered to the lender (the "Lender") the initial loan application and documentation required by the Lender, and (ii) paid all loan application fees as required by the Lender Buyer agrees to diligently work to obtain the Loan Buyer will promptly provide the Lender with any additional documentation as required by the Lender

(b) Procedure if Loan Application is denied If Buyer receives written notice from the Lender that the Lender does not approve the Loan (a "Loan Denial"), Buyer shall, no later than three calendar days thereafter, provide a copy to Seller Buyer or Seller may, within three calendar days after Seller's receipt of such notice, cancel this Contract by providing written notice to the other party In the event of a cancellation under this Section 2 3(b) (i) if the Loan Denial was received by Buyer on or before the _______ day of ___________, __________, the Earnest Money Deposit shall be returned to Buyer, (ii) if the Loan Denial was received by Buyer after that date, Buyer agrees to forfeit, and Seller agrees to accept as Seller s exclusive remedy, the Earnest Money as liquidated damages A failure to cancel as provided in this Section 2 3(b) shall have no effect on the Financing Condition set forth in Section 2 2(a) Cancellation pursuant to the provisions of any other section of this Contract shall be governed by such other provisions

2 4 Appraisal of Property Buyer's obligation to purchase the Property [ ] IS [X] IS NOT conditioned upon the Property appraising for not less than the Purchase Price If the appraisal condition applies and the Property appraises for less than the Purchase Price, Buyer may cancel this Contract by providing written notice to Seller no later than three calendar days after Buyer's receipt of notice of the appraised value In the event of such cancellation, the Earnest Money Deposit shall be released to Buyer A failure to cancel as provided in this Section 2 4 shall be deemed a waiver of the appraisal condition by Buyer

SETTLEMENT AND CLOSING Settlement shall take place on the Settlement Deadline referenced in Section 24(d), or ‑ date upon which Buyer and Seller agree in writing "Settlement" shall occur only when all of the following have been pleted (a) Buyer and Seller have signed and delivered to each other or to the escrow/closing office all documents required by this Contract, by the Lender, by written escrow instructions or by applicable law, (b) any monies required to be paid by Buyer under these documents (except for the proceeds of any new loan) have been delivered by Buyer to Seller or to the escrow/closing office in the form of collected or cleared funds, and (c) any monies required to be paid by Seller under these documents have been delivered by Seller to Buyer or to the escrow/closing office in the form of collected or cleared funds Seller and Buyer shall each pay one half (½) of the fee charged by the escrow/closing office for its services in the settlement/closing process Taxes and assessments for the current year, rents, and interest on assumed obligations shall be prorated at Settlement as set forth in this Section Tenant deposits (including, but not limited to, security deposits, cleaning deposits and prepaid rents) shall be paid or credited by Seller to Buyer at Settlement. Prorations set forth in this Section shall be made as of the Settlement Deadline date referenced in Section 24(d), unless otherwise agreed to in writing by the parties Such writing could include the settlement statement The transaction will be considered closed when Settlement has been completed, and when all of the following have been completed (i) the proceeds of any new loan have been delivered by the Lender to Seller or to the escrow/closing office, and (ii) the applicable Closing documents have been recorded in the office of the county recorder The actions described in parts (i) and (ii) of the preceding sentence shall be completed within four calendar days of Settlement.

4 POSSESSION. Seller shall deliver physical possession to Buyer within [ ] ____ hours [ ] ____ days after Closing, [x] Other (specify) on closing

5 CONFIRMATION OF AGENCY DISCLOSURE At the signing of this Contract.

[ ] Seller s Initials [ ] Buyer s Initials

The Listing Agent, ______________________________, represents [ ] Seller [ ] Buyer [ ] both Buyer and Seller as a Limited Agent,

The Selling Agent, ______________________________, represents [ ] Seller [ ] Buyer [ ] both Buyer and Seller as a Limited Agent,

The Listing Broker ______________________________, represents [ ] Seller [ ] Buyer [ ] both Buyer and Seller as a Limited Agent,

Selling Broker ______________________________, represents [ ] Seller [ ] Buyer [ ] both Buyer and Seller as a Limited Agent

The Seller is not represented by a Broker

6 TITLE INSURANCE At Settlement, Seller agrees to pay for a standard coverage owner's policy of title insurance insuring Buyer in the amount of the Purchase Price

ELLER DISCLOSURES No later than the Seller Disclosure Deadline referenced in Section 24(b), Seller shall provide to Buyer the following documents which are collectively referred to as the "Seller Disclosures"

(a) a Seller property condition disclosure for the Property, signed and dated by Seller;
(b) a commitment for the policy of title insurance,
(c) a copy of any leases affecting the Property not expiring prior to Closing,
(d) written notice of any claims and/or conditions known to Seller relating to environmental problems and building or zoning code violations, and
(e) Other (specify) ______________________________

8 BUYER'S RIGHT TO CANCEL BASED ON EVALUATIONS AND INSPECTIONS Buyer's obligation to purchase under this Contract (check applicable boxes)

[X] IS [ ] IS NOT conditioned upon Buyer's approval of the content of all the Seller Disclosures referenced in Section 7,
[ ] IS [X] IS NOT conditioned upon Buyer's approval of a physical condition inspection of the Property,
[X] IS [ ] IS NOT conditioned upon Buyer's approval of the following tests and evaluations of the Property (specify)

See Addendum "A" attached hereto and made a part hereof

If any of the above items are checked in the affirmative, then Sections 8 1, 8 2, 8 3 and 8 4 apply, otherwise, they do not apply The items checked in the affirmative above are collectively referred to as the "Evaluations & Inspections " Unless otherwise provided in this Contract, the Evaluations & Inspections shall be paid for by Buyer and shall be conducted by individuals or entities of Buyer's choice Seller agrees to cooperate with the Evaluations & Inspections and with the walk-through inspection under Section 11

8 1 Evaluations & Inspections Deadline. No later than the Evaluations & Inspections Deadline referenced in Section 24(c) Buyer shall (a) complete all Evaluations & Inspections, and (b) determine if the Evaluations & Inspections are acceptable to Buyer

8 2 Right to Cancel or Object If Buyer determines that the Evaluations & Inspections are unacceptable, Buyer may, later than the Evaluations & Inspections Deadline, either (a) cancel this Contract by providing written notice to Seller, whereupon the Earnest Money Deposit shall be released to Buyer; or (b) provide Seller with written notice of objections

8 3 Failure to Respond If by the expiration of the Evaluations & Inspections Deadline, Buyer does not (a) cancel this Contract as provided in Section 8 2, or (b) deliver a written objection to Seller regarding the Evaluations & Inspections, the Evaluations & Inspections shall be deemed approved by Buyer

8 4 Response by Seller If Buyer provides written objections to Seller, Buyer and Seller shall have seven calendar days after Seller's receipt of Buyer's objections (the 'Response Period') in which to agree in writing upon the manner of resolving Buyer's objections Seller may, but shall not be required to, resolve Buyer's objections If Buyer and Seller have not agreed in writing upon the manner of resolving Buyer's objections, Buyer may cancel this Contract by providing written notice to Seller no later than three calendar days after expiration of the Response Period, whereupon the Earnest Money Deposit shall be released to Buyer If this Contract is not canceled by Buyer under this Section 8 4, Buyer s objections shall be deemed waived by Buyer This waiver shall not affect those items warranted in Section 10

9 ADDITIONAL TERMS There [X] ARE [ ] ARE NOT addenda to this Contract containing additional terms If there are the terms of the following addenda are incorporated into this Contract by this reference [X] Addendum No "A"
[ ] Survey Addendum [ ] Seller Financing Addendum [ ] FHA/VA Loan Addendum [ ] Assumption Addendum
[ ] Lead Based Paint Addendum (in some transactions this addendum is required by law)
[ ] Other (specify) ______________________________

10 SELLER WARRANTIES & REPRESENTATIONS

10 1 Condition of Title Seller represents that Seller has fee title to the Property and will convey good and marketable title to Buyer at Closing by general warranty deed unless the sale is being made pursuant to a real estate contract which provides for title to pass at a later date In that case title will be conveyed in accordance with the provisions of that contract Buyer agrees however to accept title to the Property subject to the following matters of record easements deed restrictions CC&R s (meaning covenants conditions and restrictions) and rights of way and subject to the contents of the Commitment

for Title Insurance as agreed to by Bu, _. under Section 8 Buyer also agrees to tal ıe Property subject to existing leases affecting the Property and not expiring prior to Closing Buyer agrees to be responsible for taxes, assessments, homeowners association dues, utilities, and other services provided to the Property after Closing Except for any loan(s) specifically ssumed by Buyer under Section 2 1(c), Seller will cause to be paid off by Closing all mortgages, trust deeds, judgments, hanic's liens, tax liens and warrants Seller will cause to be paid current by Closing all assessments and homeowners c ociation dues

10 2 Condition of Property Seller warrants that the Property will be in the following condition ON THE DATE SELLER DELIVERS PHYSICAL POSSESSION TO BUYER

(a) the Property shall be broom-clean and free of debris and personal belongings Any Seller or tenant moving-related damage to the Property shall be repaired at Seller's expense,

(b) the heating, cooling, electrical, plumbing and sprinkler systems and fixtures, and the appliances and fireplaces will be in working order and fit for their intended purposes,

(c) the roof and foundation shall be free of leaks known to Seller;

(d) any private well or septic tank serving the Property shall have applicable permits, and shall be in working order and fit for its intended purpose, and

(e) the Property and improvements, including the landscaping, will be in the same general condition as they were on the date of Acceptance

11. WALK-THROUGH INSPECTION. Before Settlement, Buyer may, upon reasonable notice and at a reasonable time, conduct a "walk-through" inspection of the Property to determine only that the Property is "as represented," meaning that the items referenced in Sections 1 1, 8 4 and 10 2 ("the items") are respectively present, repaired/changed as agreed, and in the warranted condition. If the items are not as represented, Seller will, prior to Settlement, replace, correct or repair the items or, with the consent of Buyer (and Lender if applicable), escrow an amount at Settlement to provide for the same The failure to conduct a walk-through inspection, or to claim that an item is not as represented, shall not constitute a waiver by Buyer of the right to receive, on the date of possession, the items as represented

12. CHANGES DURING TRANSACTION Seller agrees that from the date of Acceptance until the date of Closing, none of the following shall occur without the prior written consent of Buyer (a) no changes in any existing leases shall be made, (b) no new leases shall be entered into, (c) no substantial alterations or improvements to the Property shall be made or undertaken, and (d) no further financial encumbrances to the Property shall be made

3. AUTHORITY OF SIGNERS. If Buyer or Seller is a corporation, partnership, trust, estate, limited liability company, or other ty, the person executing this Contract on its behalf warrants his or her authority to do so and to bind Buyer and Seller

14. COMPLETE CONTRACT. This Contract together with its addenda, any attached exhibits, and Seller Disclosures, constitutes the entire Contract between the parties and supersedes and replaces any and all prior negotiations, representations, warranties, understandings or contracts between the parties This Contract cannot be changed except by written agreement of the parties

15. DISPUTE RESOLUTION. The parties agree that any dispute, arising prior to or after Closing, related to this Contract [ ] SHALL [X] MAY (upon mutual agreement of the parties) first be submitted to mediation If the parties agree to mediation, the dispute shall be submitted to mediation through a mediation provider mutually agreed upon by the parties Each party agrees to bear its own costs of mediation If mediation fails, the other procedures and remedies available under this Contract shall apply Nothing in this Section 15 shall prohibit any party from seeking emergency equitable relief pending mediation

16 DEFAULT If Buyer defaults, Seller may elect either to retain the Earnest Money Deposit as liquidated damages, or to return it and sue Buyer to specifically enforce this Contract or pursue other remedies available at law If Seller defaults, in addition to return of the Earnest Money Deposit, Buyer may elect either to accept from Seller a sum equal to the Earnest Money Deposit as liquidated damages, or may sue Seller to specifically enforce this Contract or pursue other remedies available at law If Buyer elects to accept liquidated damages, Seller agrees to pay the liquidated damages to Buyer upon demand It is agreed that denial of a Loan Application made by the Buyer is not a default and is governed by Section 2 3(b)

17 ATTORNEY FEES AND COSTS In the event of litigation or binding arbitration to enforce this Contract, the prevailing party shall be entitled to costs and reasonable attorney fees However attorney fees shall not be awarded for participation in mediation under Section 15

!OTICES. Except as provided in Section 23, all notices required under this Contract must be: (a) in writing; (b) signed b_ e party giving notice; and (c) received by the other party or the other party's agent no later than the applicable date referenced in this Contract.

19. ABROGATION. Except for the provisions of Sections 10.1, 10.2, 15 and 17 and express warranties made in this Contract, the provisions of this Contract shall not apply after Closing.

20. RISK OF LOSS. All risk of loss to the Property, including physical damage or destruction to the Property or its improvements due to any cause except ordinary wear and tear and loss caused by a taking in eminent domain, shall be borne by Seller until the transaction is closed.

21. TIME IS OF THE ESSENCE. Time is of the essence regarding the dates set forth in this Contract. Extensions must be agreed to in writing by all parties. Unless otherwise explicitly stated in this Contract: (a) performance under each Section of this Contract which references a date shall absolutely be required by 5:00 PM Mountain Time on the stated date; and (b) the term "days" shall mean calendar days and shall be counted beginning on the day following the event which triggers the timing requirement (i.e., Acceptance, receipt of the Seller Disclosures, etc.). Performance dates and times referenced herein shall not be binding upon title companies, lenders, appraisers and others not parties to this Contract, except as otherwise agreed to in writing by such non-party.

22. FAX TRANSMISSION AND COUNTERPARTS. Facsimile (fax) transmission of a signed copy of this Contract, any addenda and counteroffers, and the retransmission of any signed fax shall be the same as delivery of an original. This Contract and any addenda and counteroffers may be executed in counterparts.

23. ACCEPTANCE. "Acceptance" occurs when Seller or Buyer, responding to an offer or counteroffer of the other: (a) signs the offer or counteroffer where noted to indicate acceptance; and (b) communicates to the other party or to the other party's agent that the offer or counteroffer has been signed as required.

CONTRACT DEADLINES. Buyer and Seller agree that the following deadlines shall apply to this Contract:

(· ·pplication Deadline	N/A	(Date)
(b) Seller Disclosure Deadline	January 25, 2002	(Date)
(c) Evaluations & Inspections Deadline	See Addendum "A"	(Date)
(d) Settlement Deadline	See Addendum "A"	(Date)

25. OFFER AND TIME FOR ACCEPTANCE. Buyer offers to purchase the Property on the above terms and conditions. If Seller does not accept this offer by: 5:00 [ ] AM [X] PM Mountain Time on Jan..4, 2002 (Date), this offer shall lapse; and the Brokerage shall return the Earnest Money Deposit to Buyer.

Theodore T. Banasiewicz

(Buyer's Signature) (Offer Date) (Buyer's Signature) (Offer Date)

The later of the above Offer Dates shall be referred to as the "Offer Reference Date"

Theodore T. Banasiewicz USA Power Partners LLC, PO 774060-359 Steamboat Springs, CO 80477

(Buyers' Names) (PLEASE PRINT) (Notice Address) (Phone)

970-871-9135

Addendum "A"
To Real Estate Purchase Contract

1 Property Description NW 1/4 of the SE 1/4 of Section 23, T 11S, R 1W, SLB&M, containing 40 acres more or less, together with a 75 foot wide access road easement and easement(s) for a natural gas pipeline, water line and well, and electrical transmission line through Seller's remaining property in the SE 1/4 of Section 23 to the specified 40 acre parcel Exact legal description of 40 acre parcel and easements to be determined by survey A reasonable time after Seller's acceptance of this offer, Buyer will locate said easements by survey If Seller sells his remaining property in the SE 1/4 of Section 23 to others than Buyer, said sale shall be subject to Buyer's easements

2 It is understood by Seller that Buyer has to do a substantial amount of preliminary investigation and study to determine whether the property is suitable for Buyer's proposed use Buyer will have a period of one (1) year from date of Seller's acceptance to perform such studies, tests, feasibility, and analysis as Buyer, in its/his sole discretion, may deem necessary to evaluate the feasibility of utilizing this property for its/his proposed uses (the "Feasibility Period") All such studies and investigations will be done at Buyer's sole expense Buyer's representatives will have reasonable access to the property to perform surveys, topographical studies, environmental, soil, and percolation tests, and any other study which Buyer in its/his sole discretion may deem necessary

3 Buyer and its purchasers or assigns agree to negotiate in good faith with Seller for access easements across the purchased 40 acre parcel in order for Seller to connect to electric, gas and water lines to provide utility service to Seller's remaining 120 acres in Section 23, T 11S, R 1W, SLB&M, provided that said access easements do not interfere with the construction, operation or maintenance of Buyer's project Buyer may determine, in its sole discretion, whether the access easements interfere with said construction, operation or maintenance, however, Buyer shall not unreasonably deny said access easements Any connection costs shall be at Seller's sole expense Seller shall be solely responsible to negotiate for the utility service to be provided by the access easements with the electricity, natural gas and water suppliers

4 The Feasibility Period may be extended up to four (4) times in increments of ninety (90) days each at Buyer's sole discretion by written notice to Seller prior to the end of the then existing Feasibility Period and payment of Five Thousand Dollars ($5,000 00) of Earnest Money (down payment) for each extension

5 All Earnest Money (down payment) paid to Seller by Buyer under this Contract and any extension of the Feasibility Period shall be applied to the balance of the purchase price due at the Closing

6 Buyer may terminate the Contract at any time during the Feasibility Period or any extension thereof by giving Seller written notice In that event, the Seller may retain all Earnest Money (down payment) previously paid, and upon such termination, this Contract will be void, and the parties will have no obligation to each other If Buyer either fails to (a) pay additional Earnest Money (down payment) or (b) approve the contingencies and continue with the purchase of the property prior to the end of each additional Feasibility Period, then the Contract will automatically terminate and all of the Earnest Money (down payment) will be retained by Seller as the complete and full amount of liquidated damages, and the Contract will be void and the parties will have no further obligation to each other

MIK 1-4-02 TR 1/4/05

7. Seller understands that Buyer's proposed use would likely require moderate industrial or heavy industrial zoning. Seller agrees to cooperate with Buyer in applying for said zoning with all costs to be at Buyer's expense. Seller will cooperate with Buyer by signing any requisite forms or applications that may be necessary to process zoning or other permits that are required by Buyer.

8. Buyer may assign this contract at any time prior to closing.

9. Seller has not entered into any mineral leases on the property, and will not do so during the term of this Contract. Seller does not have nor will enter into any agricultural, grazing or other lease that can not be cancelled upon 30 days notice.

10. There are no condemnation proceedings pending or contemplated against the property.

11. Closing of this Contract will be set for 10 days after Buyer submits written approval of all matters and conditions precedent to closing of the purchase, including but not limited to securing any permits that may be required to operate the proposed improvements on the property.

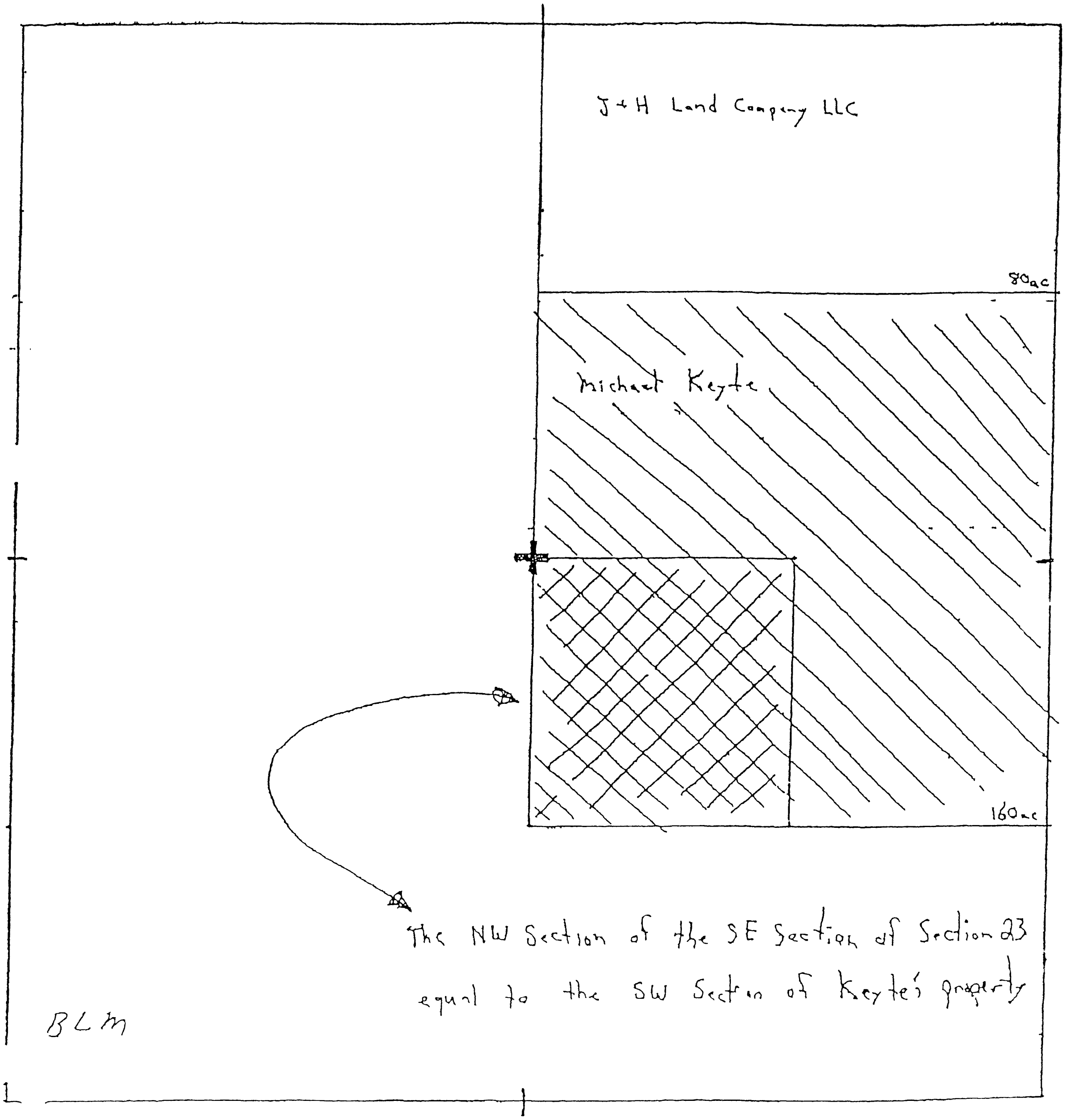
12. The Title Commitment will be delivered to Seller within fifteen (15) days from Contract acceptance. If the Title Commitment shows any easements, Seller will retain a surveyor acceptable to Buyer to locate said easements on a scaled drawing of the property.

Sellers Initials: M.J.K 1-4-02 Buyer's Initials: TB 1/4/02

Date: __________ Date: __________

Addendum "A"
Page 3'

Section 23 T 11 S, R 1 W



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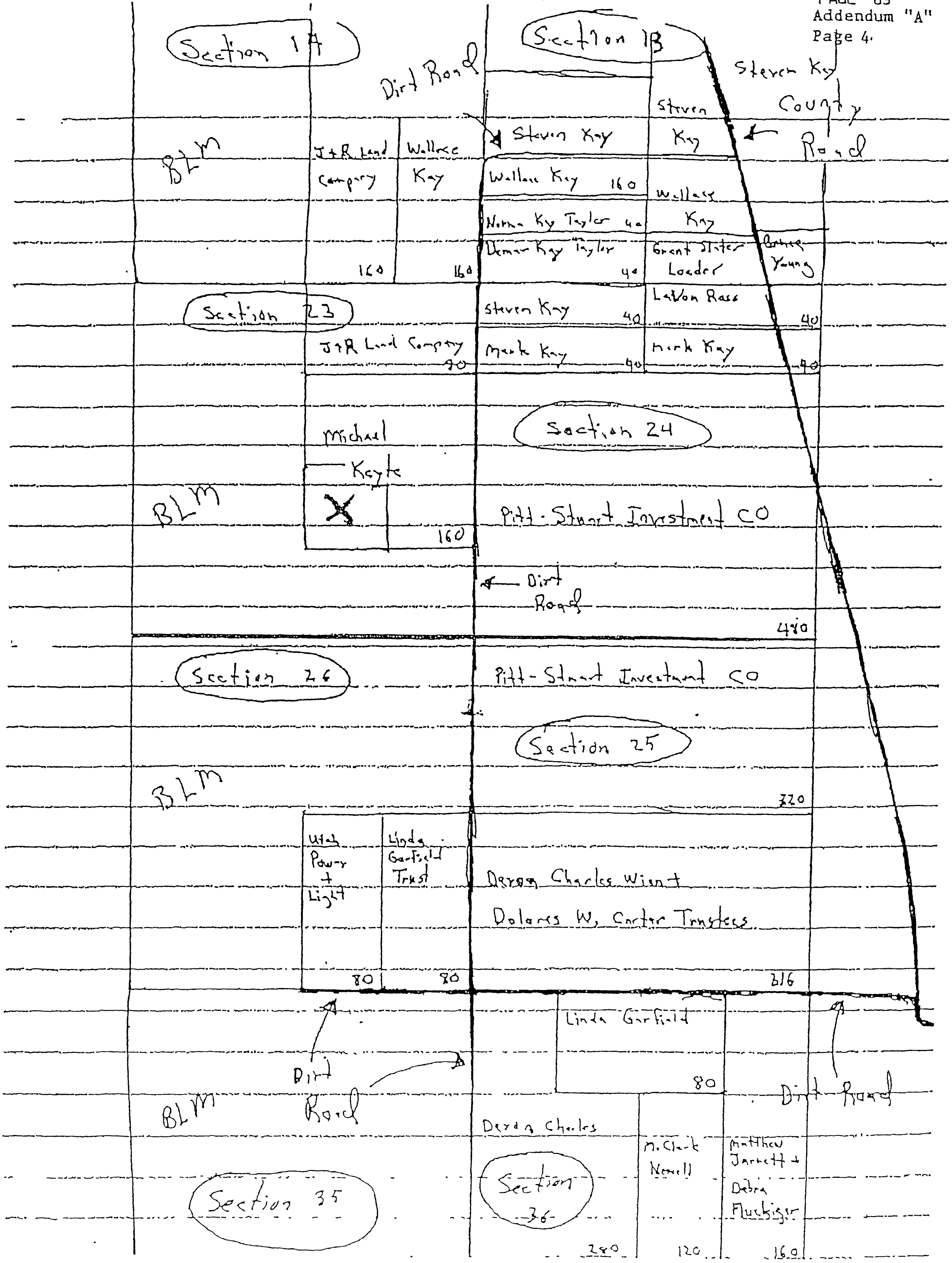
Addendum "A"
Page 4.



M. S. K. 1-4-02

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ACCEPTANCE/COUNTEROFFER/REJECTION

CK ONE:

[✓] ACCEPTANCE OF OFFER TO PURCHASE: Seller Accepts the foregoing offer on the terms and conditions specified above.

[ ] COUNTEROFFER: Seller presents for Buyer's Acceptance the terms of Buyer's offer subject to the exceptions or modifications as specified in the attached ADDENDUM NO. ________.

Michael S Keyte 1-4-02 5:00 P.M.
(Seller's Signature) (Date) (Time) (Seller's Signature) (Date) (Time)

Michael S. Keyte P.O. Box 274 Mona, Utah 84645 435-623-0508
(Sellers' Names) (PLEASE PRINT) (Notice Address) (Phone)

[ ] REJECTION: Seller Rejects the foregoing offer.

(Seller's Signature) (Date) (Time) (Seller's Signature) (Date) (Time)

****

DOCUMENT RECEIPT

State law requires Broker to furnish Buyer and Seller with copies of this Contract bearing all signatures. (Fill in applicable section below.)

I acknowledge receipt of a final copy of the foregoing Contract bearing all signatures:

(Buyer's Signature) (Date) (Buyer's Signature) (Date)

(Seller's Signature) (Date) (Seller's Signature) (Date)

B. I personally caused a final copy of the foregoing Contract bearing all signatures to be [ ] faxed [ ] mailed [ ] hand delivered on ________________ (Date), postage prepaid, to the [ ] Seller [ ] Buyer.

Sent/Delivered by (specify) ______________________________

 Seller's Initials MSK Date 1-4-02 Buyer's Initials TB Date 1/4/02

Addendum "A"
To Real Estate Purchase Contract

This Addendum revokes and replaces Addendum "A" of the Real Estate Purchase Contract dated January 4, 2002 (the "Agreement") between USA Power Partners, L.L.C. ("Buyer") and Michael S. Keyte ("Seller"). With the exception of the terms set forth in this Addendum, all other terms of the Agreement remain unchanged. The following terms are hereby incorporated as part of the Agreement:

1. Property Description: NE 1/4 of the SE 1/4 of Section 23, T 11S, R 1W, SLB&M, containing 40 acres more or less, together with a 75 foot wide access road easement and easement(s) for a natural gas pipeline, water line and well, and electrical transmission line through Seller's remaining property in the SE 1/4 of Section 23 to the specified 40 acre parcel. Exact legal description of 40 acre parcel and easements to be determined by survey. A reasonable time after Seller's acceptance of this offer, Buyer will locate said easements by survey. If Seller sells his remaining property in the SE 1/4 of Section 23 to others than Buyer, said sale shall be subject to Buyer's easements.

2. It is understood by Seller that Buyer has to do a substantial amount of preliminary investigation and study to determine whether the property is suitable for Buyer's proposed use. Buyer will have a period of one (1) year from date of Seller's acceptance to perform such studies, tests, feasibility, and analysis as Buyer, in its/his sole discretion, may deem necessary to evaluate the feasibility of utilizing this property for its/his proposed uses (the "Feasibility Period"). All such studies and investigations will be done at Buyer's sole expense. Buyer's representatives will have reasonable access to the property to perform surveys, topographical studies, environmental, soil, and percolation tests, and any other study which Buyer in its/his sole discretion may deem necessary.

3. Buyer and its purchasers or assigns agree to negotiate in good faith with Seller for access easements across the purchased 40 acre parcel to provide Seller with road access and in order for Seller to connect to electric, gas and water lines to provide utility service to Seller's remaining 120 acres in Section 23, T 11S, R 1W, SLB&M; provided that said access easements do not interfere with the construction, operation or maintenance of Buyer's project. Buyer may determine, in its sole discretion, whether the access easements interfere with said construction, operation or maintenance; however, Buyer shall not unreasonably deny said access easements. Any construction or maintenance costs for access roads or any utility connection costs shall be at Seller's sole expense. Seller shall be solely responsible to negotiate for the utility service to be provided by the access easements with the electricity, natural gas and water suppliers.

4. The Feasibility Period may be extended up to four (4) times in increments of ninety (90) days each at Buyer's sole discretion by written notice to Seller prior to the end of the then existing Feasibility Period and payment of Five Thousand Dollars ($5,000.00) of Earnest Money (down payment) for each extension.

5. All Earnest Money (down payment) paid to Seller by Buyer under this Contract and any extension of the Feasibility Period shall be applied to the balance of the purchase price due at the Closing.

6. Buyer may terminate the Contract at any time during the Feasibility Period or any

Seller's Initials MSK Date 2/7/02 Buyer's Initials JB Date 2/5/02

Addendum "A"
Page 2

extension thereof by giving Seller written notice. In that event, the Seller may retain all Earnest Money (down payment) previously paid, and upon such termination, this Contract will be void, and the parties will have no obligation to each other. If Buyer either fails to (a) pay additional Earnest Money (down payment) or (b) approve the contingencies and continue with the purchase of the property prior to the end of each additional Feasibility Period, then the Contract will automatically terminate and all of the Earnest Money (down payment) will be retained by Seller as the complete and full amount of liquidated damages, and the Contract will be void, and the parties will have no further obligation to each other.

7. Seller understands that Buyer's proposed use would likely require moderate industrial or heavy industrial zoning. Seller agrees to cooperate with Buyer in applying for said zoning with all costs to be at Buyer's expense. Seller will cooperate with Buyer by signing any requisite forms or applications that may be necessary to process zoning or other permits that are required by Buyer.

8. Buyer may assign this contract at any time prior to closing.

9. Seller has not entered into any mineral leases on the property, and will not do so during the term of this Contract. Seller does not have nor will enter into any agricultural, grazing or other lease that can not be cancelled upon 30 days notice.

10. There are no condemnation proceedings pending or contemplated against the property.

11. Closing of this Contract will be set for 10 days after Buyer submits written approval of all matters and conditions precedent to closing of the purchase, including but not limited to securing any permits that may be required to operate the proposed improvements on the property.

12. The Title Commitment will be delivered to Seller within fifteen (15) days from Contract acceptance. If the Title Commitment shows any easements, Seller will retain a surveyor acceptable to Buyer to locate said easements on a scaled drawing of the property.

Executed on the dates set forth below.

SELLER	BUYER
Michael S. Keyte	U.S.A. Power Partners, L.L.C.
	Theodore T. Barnasiewicz, Managing Partner
Date: 2-7-02	Date: 2-5-02

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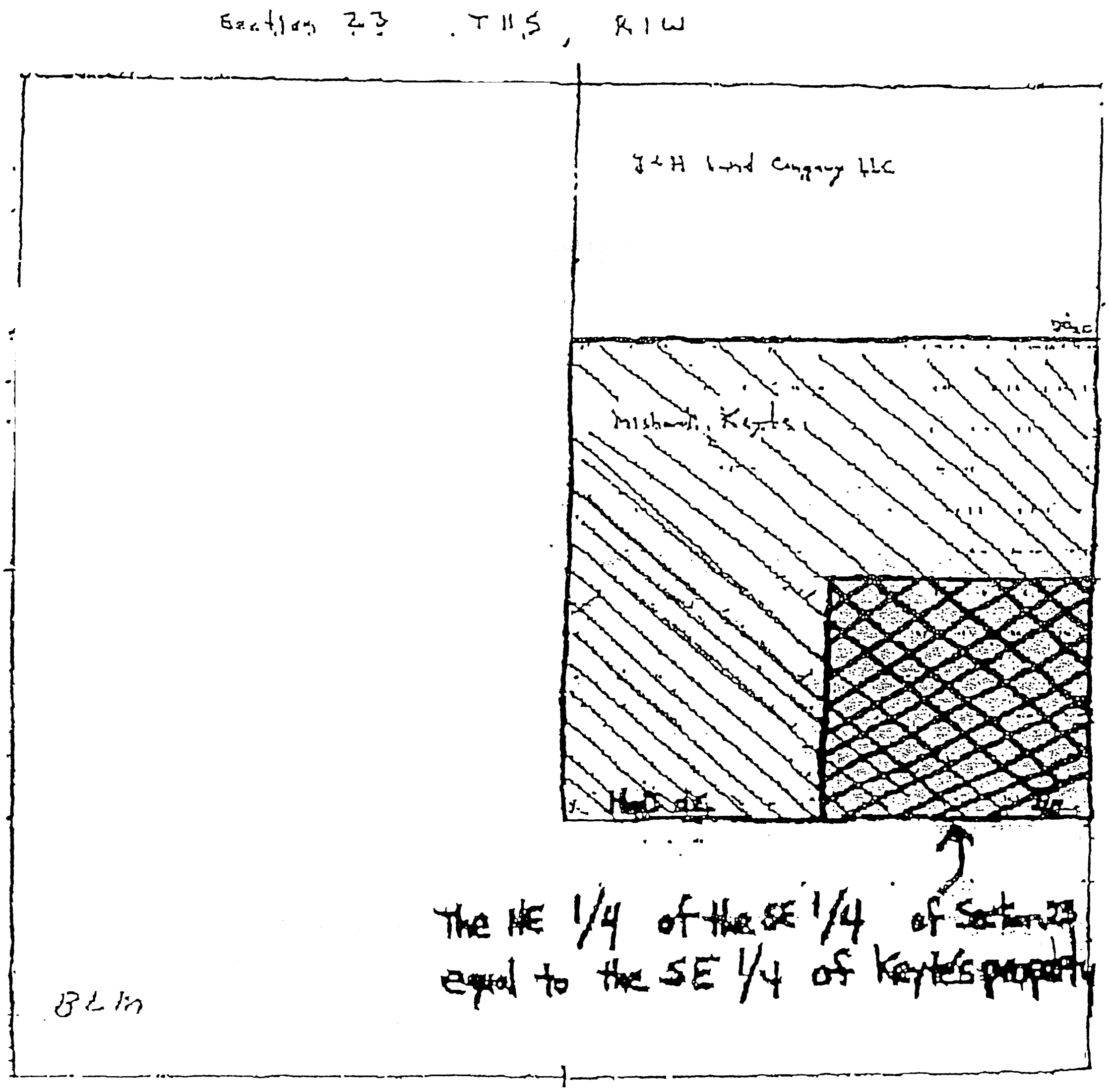

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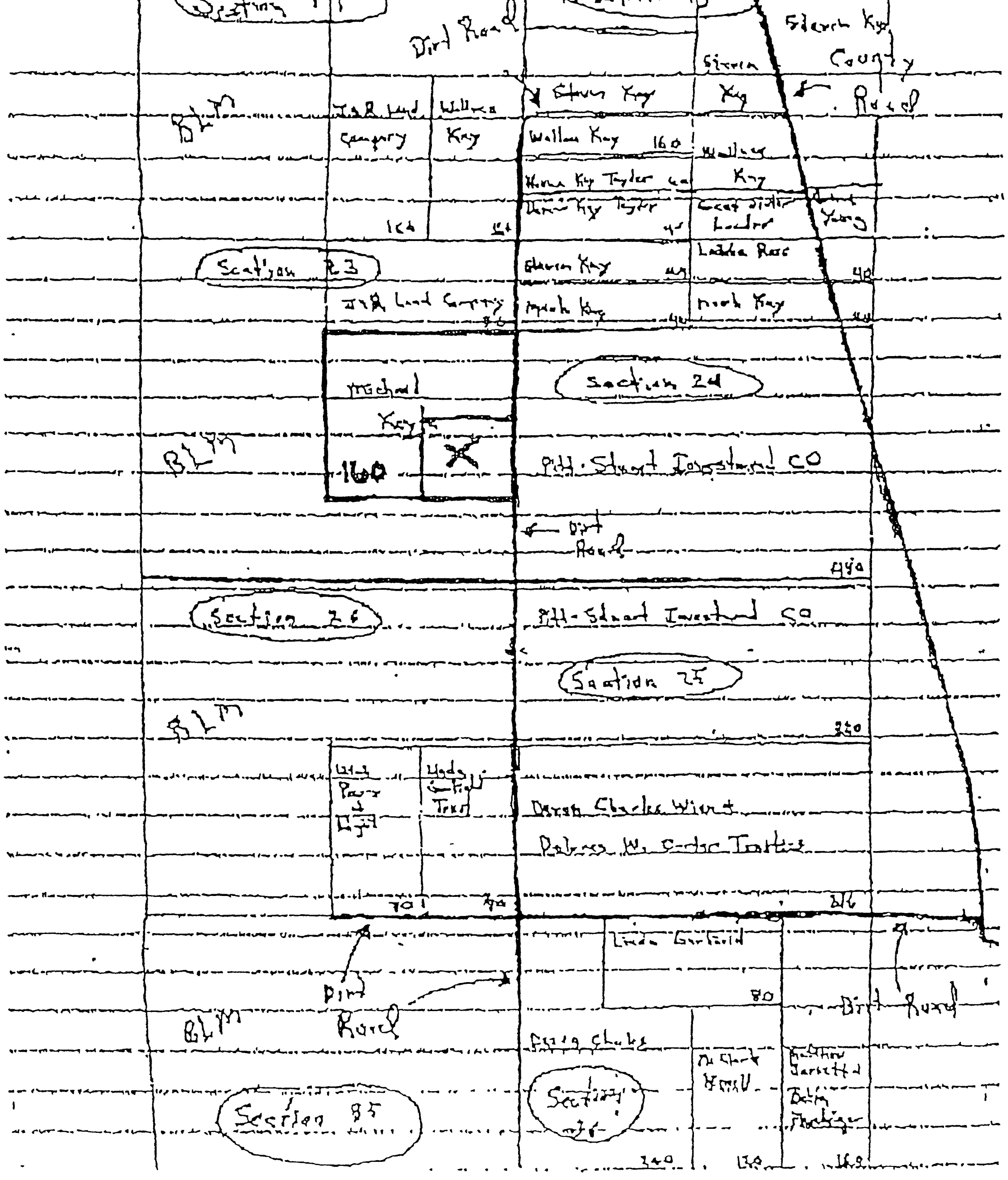
Addendum "A"
Page 4.



M. S. T. 2/7/02

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ORDINANCE NO. 7-01-02

AN ORDINANCE CHANGING THE ZONING FOR CERTAIN PROPERTIES IN SECTION 23, TOWNSHIP 11 SOUTH, RANGE 1 WEST FROM GMRF TO ID.

WHEREFORE, after a duly noticed public hearing and in conformity with the Juab County General Plan, the subject property is found suited for industrial development.

BE IT ORDAINED BY THE BOARD OF JUAB COUNTY COMMISSIONERS AS FOLLOWS:

The zoning of the following described property is hereby changed from GMRF to ID:

> NE ¼ of the SE ¼ of Section 23, Township 11 S Range 1 West, Salt Lake Baseline and Meridian, containing an area of 40 acres more or less.

The Juab County Zoning Map shall be amended accordingly.

EFFECTIVE DATE: This ordinance shall take effect within 30 days or upon publication, whichever is shorter.

Passed and approved this 1st day of July, 2002.

William Boyd Howarth

William Boyd Howarth, Commission Chairman

Attest:

Patricia M. Ingram

Patricia M. Ingram, Juab County Clerk

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A. Water Rights Opinion

Holme Roberts & Owen LLP

September 18, 2002

Mr. David Graeber
Spring Canyon Energy, LLC
10440 North Central Expressway, Suite 1400
Dallas TX 75231

Re: Spring Canyon Energy Project Water Rights

Dear Mr. Graeber:

Jody L. Williams
williajo@hro.com

ttorneys at Law

299 South Main Street
Suite 1800
Salt Lake City, Utah
84111-2263
Tel (801)521-5800
Fax (801)521-9639
www.hro.com

Salt Lake City
Denver
Boulder
Colorado Springs
London
San Francisco

You have retained us to aid you in acquiring water rights for the Spring Canyon Energy Project (the "Project"), located near the town of Mona in Juab County, Utah. After investigation with your local water engineering firm, we identified the following Utah water rights for acquisition by Spring Canyon Energy, LLC (the "Company") for use in the Project:

> Water Right No. 53-1431, Application No. D6919 and approved Change Application No. a21754, quantified by the Utah State Engineer's Office ("State Engineer") as yielding 163.22 acre feet annually, owned by Michael Keyte (the "Keyte Water Right"); and
>
> Water Right No. No. 53-97, Certificate No. 11837 quantified by the State Engineer as yielding 384.0 acre-feet annually, owned by Blake Garrett (the "Garrett Water Right"). (Collectively, the Keyte and Garrett Water Rights are referred to as the "Water Rights.")

Together the Water Rights are approved for an annual yield of 547.22 acre feet of water annually. An acre foot of water is that volume of water which would cover one acre of land one foot deep. One acre foot of water contains 325,900 gallons of water, or 43,560 cubic feet of water.

The Company entered into the Water Right Option and Purchase Agreement (the "Options") for the Garrett Water Right on August 5, 2002 and for the Keyte Water Right on August 14, 2002. The agreed-upon purchase price for the Water Rights is $4,000.00 per acre foot of water. The Options are secured by payment of Initial Option Fees of one percent of the total purchase price, which secure the Company's right to purchase the Water Rights for six months. The Options are renewable for up to thirty-six months in six month increments by the payment of one percent of the total purchase price into an established escrow account for each

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six month increment. The Initial Option Fees may be withdrawn from the escrow accounts by each seller upon completion of the following conditions precedent:

(a) acceptance of the Water Right by the Company after completion of due diligence in a sixty day due diligence period;
(b) filing of a permanent change application ("Change Application") with the State Engineer as provided for under Utah Code Annotated § 73-3-3 seeking authorization for the Water Right to be diverted and used from the Project's proposed underground water wells;
(c) delivery of an executed Water Right deed into the escrow account established for the purchase of the Water Right;
(d) delivery of an executed Memorandum of Water Right Option into the escrow account established for the purchase of the Water Right and recordation of said Memorandum in the Office of the Juab County Recorder;
(e) delivery to the escrow agent of any required approval to the transaction by a holder of any lien or encumbrance against the Water Right.

The remaining Option payments will be held in the interest bearing escrow account and applied against the purchase price for each Water Right at the closing.

The Water Rights previously have been used for irrigation. It is generally accepted among Utah water regulators that irrigation consumes one-half of the water that is diverted and applied to the growing crops. The other one-half of the water diverted ultimately returns to the groundwater aquifer or to surface flows to be used by other water rights owners. We have advised the Company that only the portions of the Water Rights that historically have been consumed by crops may be consumed by the Project. Further, we have advised the Company that it is necessary to acquire each Water Right in its entirety and consume only that volume of water previously consumed in order to avoid unlawful interference to other water rights in the aquifer.

The Company and the Sellers must secure permission from the State Engineer to make the following changes to the Water Rights so that they may be used by the Project by receiving approval of the Change Applications.

(i) change the use of the Water Rights from irrigation to industrial and other incidental uses, including domestic;
(ii) change the points of diversion from the existing Keyte and Garrett wells to new wells to service the Project;
(iii) change the place of use of the Water Rights from the Keyte and Garrett agricultural fields to the Project site; and
(iv) change the season of use from the irrigation season to year round.

After filing, the Change Applications are advertised once a week for two consecutive weeks in a local newspaper, after which those objecting have twenty days in which to file a protest. Following the protest period, the State Engineer will either schedule a hearing, upon twenty days notice, or will issue a memorandum decision approving or denying the Change Applications. The Change Application applicants or protestants may file a request for reconsideration within twenty days from the State Engineer's memorandum decision or file an appeal with Utah District Court within thirty days from the State Engineer's memorandum decision. Many Change Applications are protested in Utah, but only a minute percentage of protests result in appeals to the Utah District Court.

Both Keyte and Garrett signed the Change Applications we prepared for their Water Rights. The Keyte Change Application, a27051, was filed on September 3, 2002. The Garrett Change Application, a27090, was filed September 17, 2002. Prior to receipt of protests, applicants or their attorneys may consult with or seek advice regarding Change Applications from the State Engineer. We have met with the State Engineer regarding both Change Applications and incorporated his suggestions into the documents. We requested the State Engineer to expedite processing and approval of the Change Applications. The earliest the Company can expect to receive the State Engineer's memorandum decision is four months from the date of filing.

At this point, we believe that the State Engineer's approval of the Change Applications is likely. The Water Rights are recognized as valid by the State Engineer and our preliminary due diligence found nothing to indicate that the Change Applications will not be approved. We do expect to receive protests to the Change Applications from the United States Bureau of Reclamation and the Central Utah Water Conservancy District. Both parties routinely protest all Change Applications in the Project area. Their protests generally request that accurate records of use be provided to the State Engineer and that consumption of water made available by the Water Rights does not increase over historical consumption. By statute, any interested person may protest and it is possible that others may file a protest to the Change Applications.

Although we have reviewed the files at the State Engineer's office and all documents provided to us by the title companies acting as escrow agents for the Options, and attempted to anticipate likely protestants and the substance of the protests, it is not possible to predict with certainty all issues which may be raised. If the Change Applications are protested, we intend to respond in writing to the protests and meet with the protestants to attempt to resolve the protests without a hearing. Based on our experience, our review to date of the Water Rights, and our meetings with the State Engineer's office, we believe the Change Applications will be promptly approved.

If you have further questions regarding the Water Rights, the Options, or the approval process for use of the Water Rights by the Project, please do not hesitate to contact us.

Sincerely,

Jody L. Williams

Jody L. Williams

JLW/bjw

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B. Due Diligence Memorandums

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Holme Roberts & Owen LLP

Privileged and Confidential
Attorney Work-Product

MEMORANDUM

To: Mr. David Graeber

From: Jody L. Williams and Steven J. Vuyovich

Date: September 30, 2002

Re: Michael S. Keyte Water Right

INTRODUCTION

The following Memorandum addresses the issues pertaining to the due diligence undertaken for Water Right No. 53-1431 (a21754) which is the subject of the Option and Purchase Agreement executed between Spring Canyon Energy, L.L.C. and Michael S. Keyte on August 14, 2002 (the "Water Right"). Based upon the records available in the file for the Water Right at the Utah Division of Water Rights, and a preliminary title report, conveyance documents, and a Utah District Court judgment supplied to us by Juab Title and Abstract Company of Mona, Utah, the Water Right is owned by Michael S. Keyte.

The Water Right is a diligence claim filed by Michael S. Keyte for the use of surface water prior to 1903. The Water Right allows the sole supply annual diversion of 163.22 acre feet of water with a priority date of March 1879 from three underground water wells located N 2300 feet and E 1300 feet; N 2000 feet and E 1300 feet; and N 2010 feet and E 1300 feet all from the SW corner of Section 30, T 11S, R 1E, SLBM. The Water Right is used for the irrigation of 40 acres, the stockwatering of 83 head of cattle or equivalent, and the domestic use of 2 families. The water may be used for irrigation from April 1 to October 31 of each year. Stockwatering and domestic uses are year round uses. The Water Right is discussed in more detail below.

DISCUSSION

The Water Right is designated as Water Right No. 53-1431 in the records of the Utah Division of Water Rights ("Division of Water Rights"). The underlying basis of the Water Right is a diligence claim meaning that the water was put to beneficial use prior to 1903 when Utah began requiring written applications for water right appropriations. Documentation of prior 1903 use of the water is required to acquire a water right number or to file an application to change the use of a water right. That documentation was first filed on September 29, 1992.

The Water Right originally was a part of Water Right No. 53-1297 (Diligence Claim No. D6213), filed in the name of Collective Water User Property Owners, claiming a priority date of March, 1879 for use of water diverted from West Ponds and springs in the Current Creek drainage. More specifically, the claim stated, "[t]he West canal collects water from 6 or more unnamed springs and 2 named ponds" and "[i]n the past, ponds were called West Pond Springs, Willow Creek Meadow Springs, East Fish Spring, & Middle Pond & West Pond." The claim stated that "100% of water has been used without interruption" and that "[e]arly users felt it was not necessary to file because water was used on patented land granted by US Govt." The original claim was for 7 cfs of water for the sole supply irrigation of 100 acres and stockwatering of 350 cattle or equivalent.

Water Right No. 53-1297 (Diligence Claim No. D6213) was amended by a subsequent filing on October 19, 1992. The corrected filing was for 7.9 cfs of water for the irrigation of 122 acres and the stockwatering of 350 cattle or equivalent. The corrected claim included 40 acres in Section 30, T 11S, R 1E, SLBM as a portion of the place of use of the water: 10 acres in the NE of the SW; 20 acres in the NW of the SE; and 10 acres in the SW of the NE. In addition to other listed claimants, the corrected claim was signed by the Erma Keyte Trust and Marilyn Keyte. The claim had been prepared for Michael Keyte's signature, but Michael's name was crossed out and Marilyn signed the claim.

Claims to the relevant irrigated acreage were as follows Erma Keyte (2 acres in the NW of the NE), Marilyn Keyte (10 acres in the NE of the SW and 20 acres in the NW of the SE), and Erma Keyte (10 acres in the SW of the NE). Marilyn Keyte then filed a change application on June 19, 1996 for 30 acres and 35 head of stock that she claimed under the corrected claim The change application was designated as Water Right No.

53-1385 (a20136). Attorney Steven Clyde protested Change Application No. a20136 for Michael Keyte, claiming that Marilyn had "nothing that will show title to this land and the water rights appurtenant to that land as vesting in her.... Marilyn Keyte has no right, title or interest in this proportionate share of Diligence Claim D6213 (53-1297)." Mr. Clyde stated that Michael Keyte had unequivocal title to the "land and the water right appurtenant to it" and that Michael's ownership was "by clear and unbroken chain of title."

A hearing on Change Application a20136 was held on July 29, 1997 in Spanish Fork, Utah. Marilyn Keyte had passed away and her heirs attended the hearing. The Change Application was subsequently rejected by the State Engineer in a Memorandum Decision dated October 21, 1997 on the grounds that the applicant did not own the property that was historically irrigated and "could not and did not establish a water right on the property." A Request for Reconsideration was filed by Larry Ellertson. The Request for Reconsideration was two days late and was denied because it was late and because no title documents could be submitted to show a claim of ownership to the water right. The 30 acres of irrigation and 35 head of stock under Change Application No. a20136 were moved back to underlying Water Right No. 53-1297.

Michael S. Keyte and Tyler P. Keyte filed Change Application No. a21754 (Water Right No. 53-1409 (a portion of Water Right No. 53-1297)) on December 16, 1997 (the "Change Application"). Tyler P. Keyte's name has subsequently been removed from the Change Application by assignment dated May 30, 2002. The Change Application was filed on 163.22 acre feet of water for the irrigation of 40 acres and the stockwatering of 115 head of cattle or equivalent. The Change Application proposed to change the point of diversion, place and nature of use of the water. The point of diversion was changed from the West Ponds and Springs in Section 6, T12S, R1E, SLBM of the Current Creek drainage to three underground water wells in Section 30, T 11S, R1E, SLBM. The place of use was changed to the S1/2 of the NW and the N1/2 of the SW of Section 30 The nature of use was changed to the irrigation of 40 acres, the stockwatering of 83 cattle or equivalent, and the domestic purposes of 2 families.

On December 1, 1998 Michael Keyte filed his own diligence claim for the use of water prior to 1903 The diligence claim was designated as D71856 (Water Right No 53-1431) and claimed a flow of .95 cfs for the irrigation of 45 06 acres and the stockwatering of 150 cattle or equivalent

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On March 5, 1999, Change Application No. a21754 (Water Right No. 53-143 1) was approved for the irrigation of 40 acres, the stockwatering of 83 cattle or equivalent, and the domestic purposes of 2 families. The maximum allowable annual diversion amount is 163.22 acre feet of water. Water Right No. 53-1409 was removed from the records of the State Engineer and Water Right No. 53-1297 was reduced by 40 acres of irrigation and 100 head of livestock.

The following inconsistencies are evident when the above documents are analyzed in detail:

1. The place of use of the water under Water Right No. 53-1297 (D6213), Change Application No. a21754 (heretofore), and Water Right No. 52-1431 (D71856) are inconsistent. See the attached Exhibits "A," "B," and "C." Exhibit "A" shows the place of use of Michael Keyte's water under Water Right No. 53-1297 (D6213); Exhibit "B" shows the heretofore place of use of the Change Application; and Exhibit "C" shows the place of use of Water Right No. 53-1431 (D71856).

2. The amount of water reduced from Water Right No. 53-1297 is 162.8 acre feet. The amount of water approved under the Change Application is 163.22 acre feet. Finally, the amount of water claimed under Water Right No. 53-1431 (D71856) is 188.44 acre feet.

3. The point of diversion of the Water Right does not perfectly match the point of diversion set forth in Water Right No. 53-1297 and the point of diversion set forth in the heretofore of the change application. The Diligence Claim lists a point of diversion of S 350 feet and E 1760 feet from the NW corner of Section 6, T 11S, R 1E, SLBM. Water Right No. 53-1297 and the heretofore of Change Application No. a21754 show a point of diversion of S 200 feet and E 1900 feet from NW corner of Section 6, T 11S, R 1E, SLBM.

Diligence Claim No. 71856 was examined closely by the Division of Water Rights prior to the approval of the Change Application. It is not clear why these discrepancies were not corrected or why Diligence Claim No. 71856 contained more water than was included in the Change Application. Representatives of the Division of

Water Rights could not tell us. It could be that additional acreage was included in the claim when the proof engineer mapped it, but the acreage was not recognized as continuously irrigated since 1903. It is not likely to matter now because the controlling document is the approved Change Application, which claims the lesser amount of water. Although Diligence Claim No. D71856 was filed for more water than what was approved in the Change Application, the change amended the diligence claim and was not appealed by Michael Keyte. Consequently, the 163.22 acre feet of water and the beneficial uses set forth in the Change Application are the annual diversion limitations of the Water Right presently recognized by the State of Utah.

The approved place of use for the Water Right under the Change Application includes the SW and the SE of the NW and the NW and the NE of the SW of Section 30, T 11S, R 1E, SLBM. Michael Keyte's deeded land is located in the SE of the NW and the NE of the SW of Section 30 (see the attached Exhibit "D" where the land is shown in a checkered pattern). Michael does not own any land in the SW of the NW or the NW of the SW of Section 30, so it is not clear why this property was included as part of the hereafter place of use of the water. We asked Michael about this and he did not know. It is likely that an error was made in the preparation of the Change Application.

A preliminary title report and commitment for title insurance issued by Juab Title & Abstract Company on September 4, 2002 (attached to this Memorandum as Exhibit "E") states that Michael S. Keyte and Nila Keyte own fee simple title to the land depicted in Exhibit "D." An examination of the deeds included with the diligence claim filing reveals that Michael Keyte has a record chain of title to the property shown in Exhibit "D" dating from March 11, 1935 where F.A. Keyte conveyed the property to Rachel Keyte, his wife. Juab Title and Abstract Company stated in a letter dated January 15, 1997, that it was unable to locate a recorded deed from Ephraim Ellertson to F.A. Keyte. Ephraim Ellertson was the recipient of the original United States patent incorporating the property now owned by Michael Keyte. The original patent was recorded on June 19, 1907. Pursuant to the Utah Marketable Title Act, "an unbroken chain of title of record to any interest in land for forty years or more" is sufficient to convey record title to the land free of third party claims "existing prior to the effective date of the root of title."

Prior to the approval of the Change Application, only a small portion of the water was used to irrigate Michael Keyte's deeded land. Historically, most of the water under the Water Right has been used to irrigate land that Michael does not and has never owned. Michael Keyte related to us that the land had belonged to F.A. Keyte and was condemned by Utah Lake Land, Water and Power Company, but the Water Right was not Included in the condemnation take. We contacted Juab Title and Abstract Company and were subsequently supplied with a preliminary title report, some deeds and a 1916 recorded court judgment in *Utah Lake Land, Water and Power Company v. Frederick A. Keyte* (the "Judgment"). The deeds and the Judgment establish that Frederick A. Keyte had title to the land in 1916 when the Fifth Judicial District Court of Utah issued an Order of Condemnation for four parcels of land in Sections 30 and 31 of T 11S, R 1E, SLBM for use as a reservoir (Now Mona Reservoir). Three of the condemned parcels are part of the historic place of use of the Water Right (see attached Exhibit "F"). The condemned parcels were flooded regularly when water was impounded. The Judgment stated that the condemnation "shall not carry with it the right to fence the lands herein condemned" or "carry any title to any water rights heretofore owned by defendants and used upon the said lands condemned." We instructed Juab Title and Abstract Company to search for documents purporting to convey water without land. No such documents were located and supplied to us. Michael Keyte informed us that the reason he filed his change application to move the irrigation water covered by his water right to his deeded land is because the flooding still occurs on a regular basis and he wanted to use all of his water on his deeded land.

One remaining issue requiring consideration is whether the Water Right has been lost to forfeiture or abandonment. Since all water in the State of Utah is "the property of the public," a person holding title to a water right actually owns only the right to the use of water which has been approved for use under the water right, and a failure to continually put that water to beneficial use may result in a loss of a water right due to forfeiture or abandonment. Forfeiture is the deprivation or destruction of the right to use water as a result of a failure to put water that was available in priority under the water right to beneficial use. Abandonment is the voluntary relinquishment of a right to use water with the intention of not reclaiming it. Generally, non-use of water under a water right for any five-year period causes the water right to cease and the water to revert to the public, unless an Application for Non-use of Water is filed with the Utah Division of Water Rights and approved by the State Engineer. We have made no independent investigation of the continuous use of the Water Right, although we know of no facts which would lead us to believe the Water Right has been abandoned or forfeited.

As a protection against loss of the Water Right from forfeiture or abandonment, the Water Right Option and Purchase Agreement executed by Spring Canyon Energy, L.L.C. and Michael Keyte contains the following Representation and Warranty by the Seller which is applicable as of the closing date and which specifically survives the closing date:

No Forfeiture or Abandonment. The water right is in good standing in the State Engineer's Office; the use of the Water Right has been consistent with the water right as on record in the State Engineer's Office; the water right has been used beneficially within the last five (5) years; and neither the water right nor any part thereof is subject to forfeiture or abandonment for non use.

Based upon the foregoing, we believe the Water Right is in good standing in the Office of the State Engineer and titled in the name of Michael S. Keyte.

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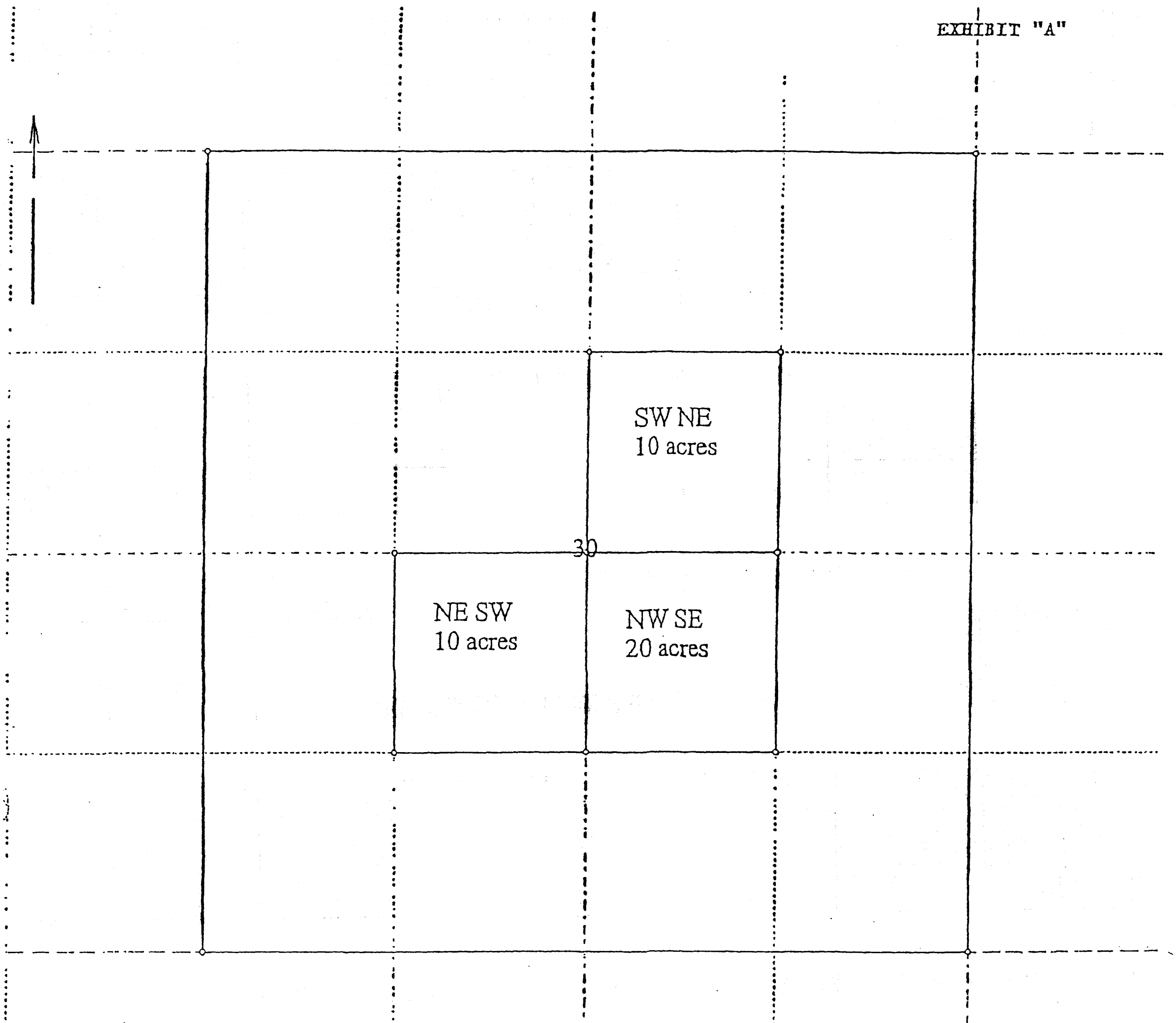
EXHIBIT "A"



Title: Place of Use Water Right No. 53-1297	Date: 09-09-2002
Scale: 1 inch = 1000 feet	File: 53-1297pou.des

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Tract 3: 40.000 Acres: 1742400 Sq Feet: Closure = n00.0000e 0.00 Feet: Precision >1/999999: Perimeter = 5280 Feet
Tract 4: 640.000 Acres: 27878400 Sq Feet: Closure = n00.0000e 0.00 Feet: Precision >1/999999: Perimeter = 21120 Feet

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003=/N90W 2640.00
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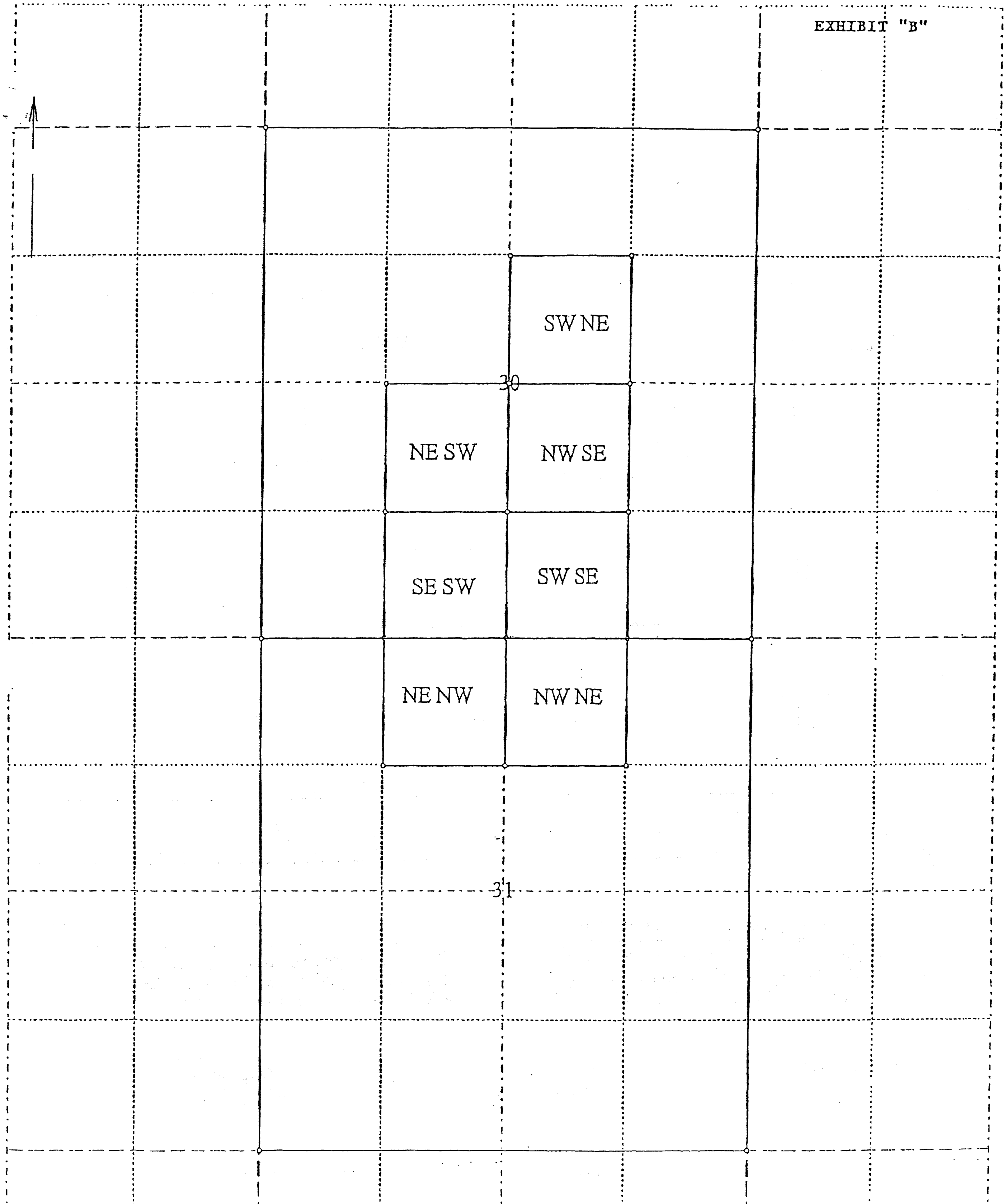
EXHIBIT "B"



Title: Place of Use Heretofore Change a21754	Date: 09-09-2002
Scale: 1 inch = 1333 feet	File:

P205

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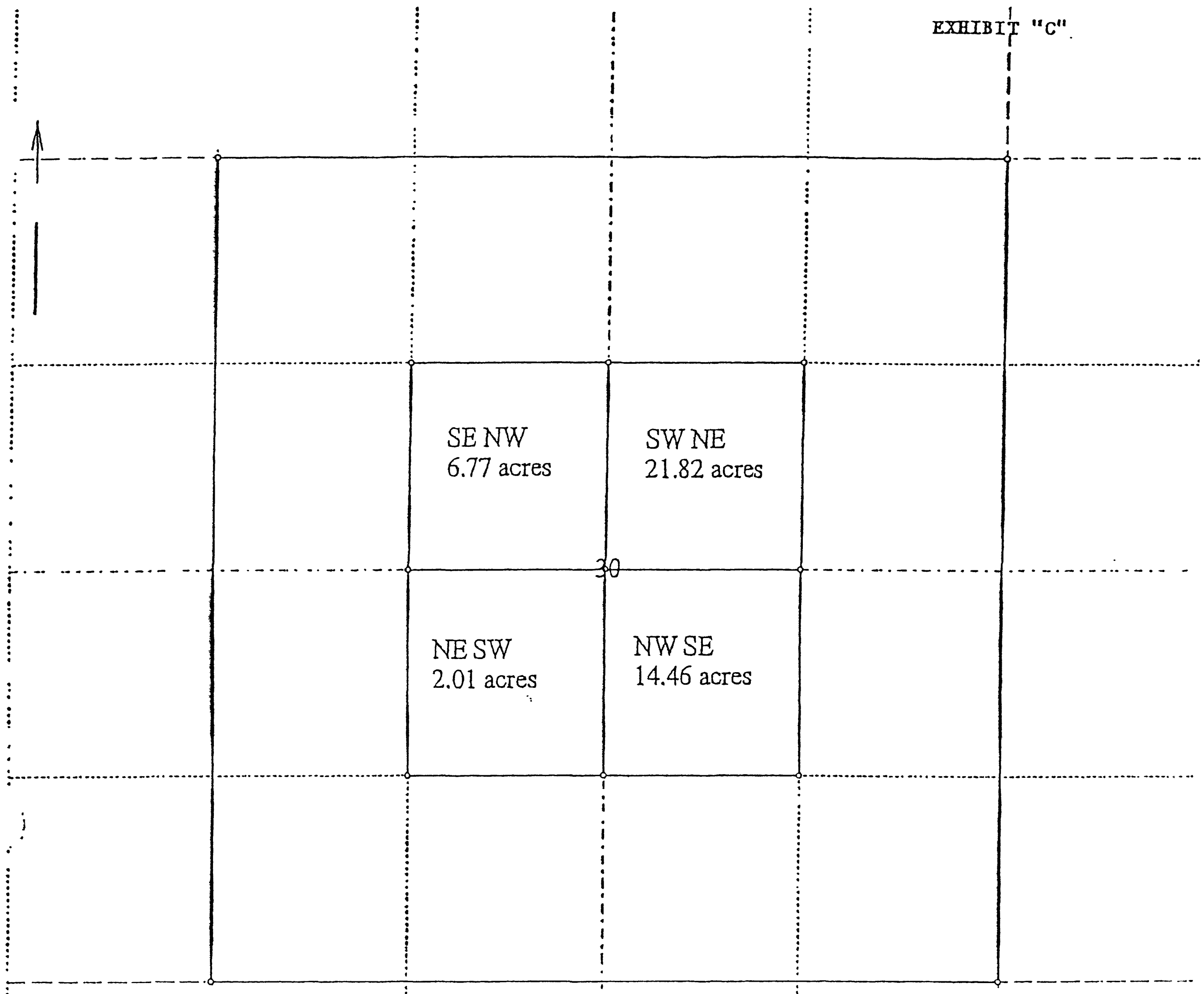
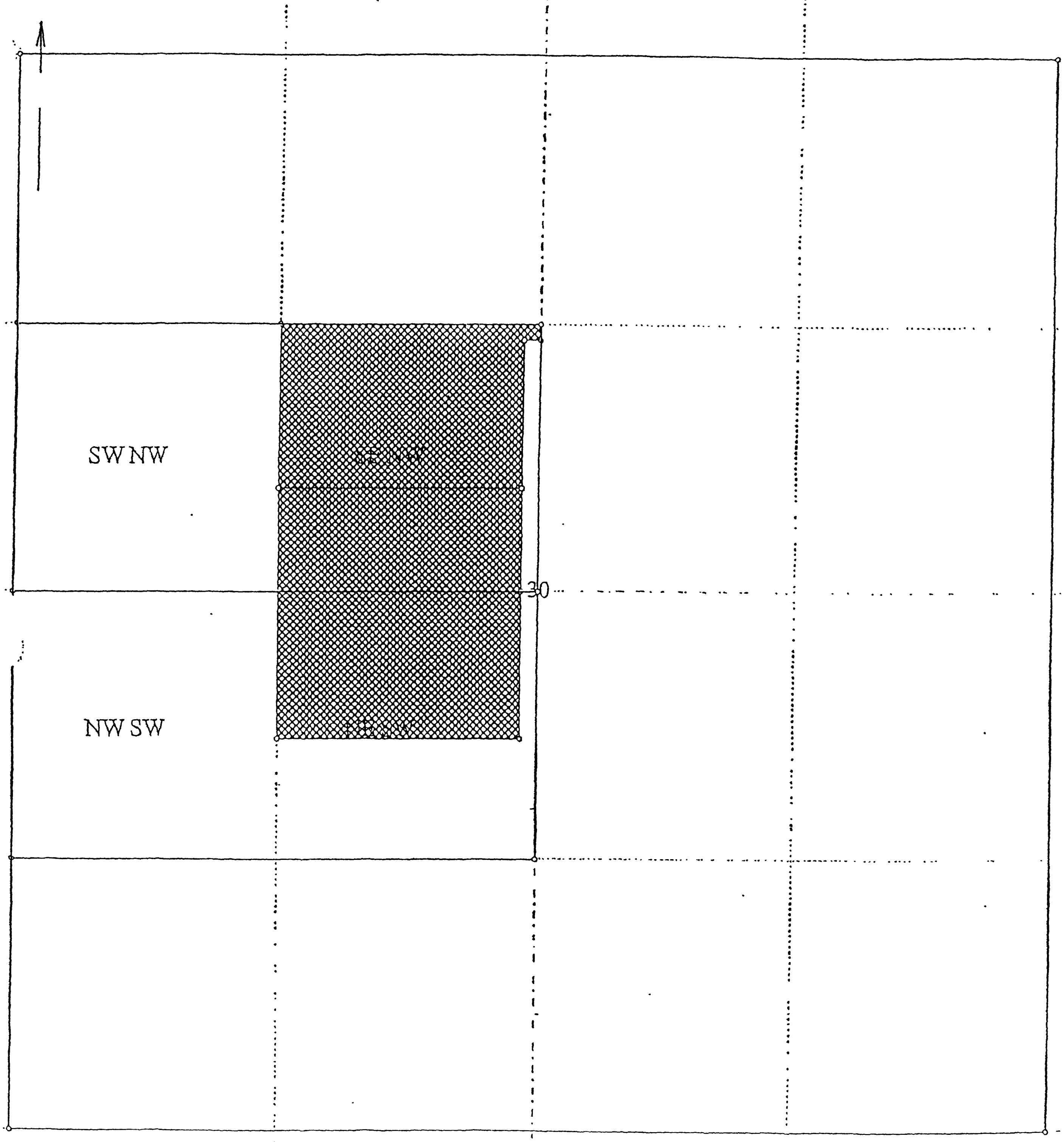
EXHIBIT "C".



Title: Diligence Claim D71856	Date: 09-09-2002
Scale: 1 inch = 1000 feet	File: DiligenceClaimD71856.des

EXHIBIT "D"



Title: Place of Use Change Application No. a21754	Date: 08-27-2002
Scale: 1 inch = 667 feet	File: Changepou.des

P207

9882

Form No. 1343 (Utah) - 90
ALTA Plain Language Commitment

EXHIBIT "E".

COMMITMENT FOR TITLE INSURANCE

ISSUED BY

Order No. 20761

JUAB TITLE & ABSTRACT COMPANY

240 North Main • P.O. Box 246 • Nephi, Utah 84648
(435) 623-0387 • Fax (435) 623-1000

Holme Roberts & Owen LLP
111 East Broadway, Suite 1100
Salt Lake City, Utah 84111-5233

Re: Michael S. Keyte and Nila Keyte

Attention: Steven J. Vuyovich

We agree to issue a policy to you according to the terms of this Commitment. When we show the policy amount and your name as the proposed Insured in Schedule A, this Commitment becomes effective as of the Commitment Date shown in Schedule A.

If the Requirements shown in this Commitment have not been met within six months after the Commitment Date, our obligation under this Commitment will end. Also, our obligation under this Commitment will end when the Policy is issued and then our obligation to you will be under the Policy.

Our obligation under this Commitment is limited by the following:

The Provisions in Schedule A.

The Requirements in Schedule B-1.

The Exceptions in Schedule B-2

The Conditions on the inside cover page.

The Commitment is not valid without SCHEDULE A and Sections 1 and 2 of SCHEDULE B.

FIRST AMERICAN TITLE INSURANCE COMPANY
INCORPORATED
SEPTEMBER 24
1968
CALIFORNIA

First American Title Insurance Company

BY PRESIDENT

ATTEST SECRETARY

BY COUNTERSIGNED

Form No. 1344-A (1982)
ALTA Plain Language Commitment

SCHEDULE A

1. Commitment Date: September 4, 2002 at 8:00 A.M. Commitment No: 20761

2. Policy or Policies to be issued:

			Amount	Premium
(a)		Owner's Policy	$	$
	Proposed Insured:			
(b)		Loan Policy	$	$
	Proposed Insured:			
(c)	✓	Title Report		$200.00

3. Fee simple interest in the land described in this Commitment is owned, at the Commitment Date by:

MICHAEL S. KEYTE and NILA KEYTE,
husband and wife,
as joint tenants with full right of survivorship

4. The land referred to in this commitment is situated in the County of Juab, State of Utah, and is described as follows:

Parcel No. XB-1693-1: Beginning 5 rods West and 31 rods North of the Southeast corner of the Northwest quarter of Section 30, Township 11 South, Range 1 East, Salt Lake Meridian, thence West 75 rods, thence North 49 rods, thence East 80 rods, thence South 80.3 feet, thence West 5 rods, thence South 44 rods 3 links to the place of beginning.

Parcel No. XB-1693-2: Beginning 5 rods West of the center of Section 30, Township 11 South, Range 1 East, Salt Lake Meridian, thence South 44 rods, thence West 75 rods, thence North 75 rods, thence East 75 rods, thence South 31 rods to the place of beginning.

-o-o-o-o-

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9884

Form No. 1344-B1 (1982)
ALTA Plain Language Commitment

No. 20761

SCHEDULE B - Section 1

Requirements

The following requirements must be met:

(a) Pay the agreed amounts for the interest in the land and/or the mortgage to be insured.

(b) Pay us the premiums, fees and charges for the policy.

(c) Documents satisfactory to us creating the interest in the land and/or the mortgage to be insured must be signed, delivered and recorded.

(d) You must tell us in writing the name of anyone not referred to in this Commitment who will get an interest in the land or who will make a loan on the land. We may then make additional requirements or exceptions.

(e) Releases(s) or Reconveyance(s) of item(s) none.

(f) Other

(g) You must give us the following Information:

1. Any off record leases, surveys, etc.

2. Other

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1005

Form No. 1344 B2 (UTAH) - 90
ALTA Plain Language Commitment

No. 20761

SCHEDULE B - Section 2

Exceptions

Any policy we issue will have the following exceptions unless they are taken care of to our satisfaction.

PART I:

1. Taxes or assessments which are not shown as existing liens by the records of any taxing authority that levies taxes or assessments on real property or by the public records.

2. Any facts, rights, interests or claims which are not shown by the public records but which could be ascertained by an inspection of said land or by making inquiry of persons in possession thereof.

3. Easements, claims of easement or encumbrances which are not shown by the public records.

4. Discrepancies, conflicts in boundary lines, shortage in area, encroachments or any other facts which a correct survey would disclose, and which are not shown by the public records.

5. Unpatented mining claims: reservations or exceptions in patents or in acts authorizing the issuance thereof: water rights, claims, or title to water.

6. Any lien, or right to a lien, for services, labor or material theretofore or hereafter furnished, imposed by law and not shown by the public records.

7. Taxes for the year 2002 now a lien not yet due (Serial No. XB-1693-1 and XB-1693-2). Taxes for the year 2001 in the amount of $18.08 paid in full.

8. Reservoir purposes and rights granted to Utah Lake Land, Water and Power Company, a corporation, and to their successors in interest, as shown and described in Judgment recorded on May 15, 1916, as Entry No. 21178, in Book 84, Page 292, and in other instruments, of the records of Juab County, Utah (affects Parcel XB-1693-1).

9. The effect of the 1969 Farmland Assessment Act, wherein there is a five year roll-back provision with regard to assessment and taxation, which becomes effective upon a change in the use of all or part of eligible land, by reason of those certain Applications for Assessment and Taxation of Agricultural Land, recorded on December 8, 1975, as Entry No. 139066, in Book 244, Page 411, of the records of Juab County, Utah, and recorded on December 23, 1992, as Entry No. 198374, in Book 355, Page 262, of the records of Juab County, Utah (affects Parcel XB-1693-2).

10. The effect of the 1969 Farmland Assessment Act, wherein there is a five year roll-back provision with regard to assessment and taxation, which becomes effective upon a change in the use of all or part of eligible land, by reason of that certain Application for Assessment and Taxation of Agricultural Land, recorded on December 13, 1976, in Book 252, Page 415 and 416, of the records of Juab County, Utah, and recorded on August 23, 1993, in Book 358, Page 558, of the records of Juab County, Utah (affects Parcel XB-1693-1).

-0-0-0-0-

(continued)

he following numbered exceptions ________ will be eliminated in an ALTA Extended Coverage Policy

Continuation of SCHEDULE B - Section 2
Exceptions

No. 20761

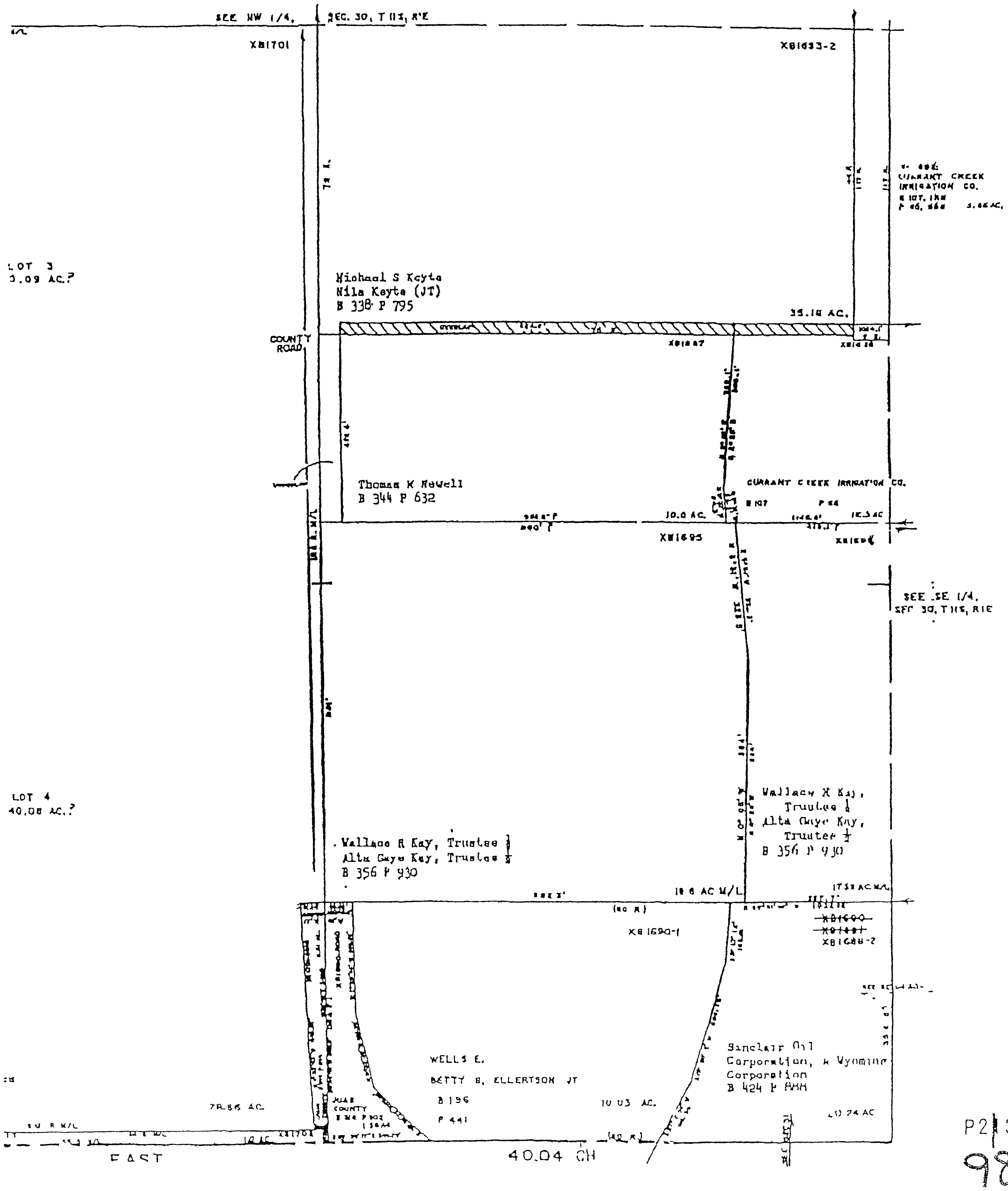
Note: The names of Michael S. Keyte and Nila Keyte have been checked for judgments and those found of record are referenced above.

Note: The policy to be issued as a result of this Commitment contains an Arbitration Clause set forth in the Conditions and Stipulations section. The following is included for the information of the proposed insured:

ANY MATTER IN DISPUTE BETWEEN YOU AND THE COMPANY MAY BE SUBJECT TO ARBITRATION AS AN ALTERNATIVE TO COURT ACTION PURSUANT TO THE RULES OF THE AMERICAN ARBITRATION ASSOCIATION OR OTHER RECOGNIZED ARBITRATOR. A COPY OF WHICH IS AVAILABLE ON REQUEST FROM THE COMPANY. ANY DECISION REACHED BY ARBITRATION SHALL BE BINDING UPON BOTH YOU AND THE COMPANY. THE ARBITRATION AWARD MAY INCLUDE ATTORNEY'S FEES IF ALLOWED BY STATE LAW AND MAY BE ENTERED AS A JUDGMENT IN ANY COURT OF PROPER JURISDICTION.

XB 1693-1-12775

, SECTION 30, T 11 S, R1E, S.L.B.&M.



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ECTION 30, T 11 S, R1E, S.L.B.&M.

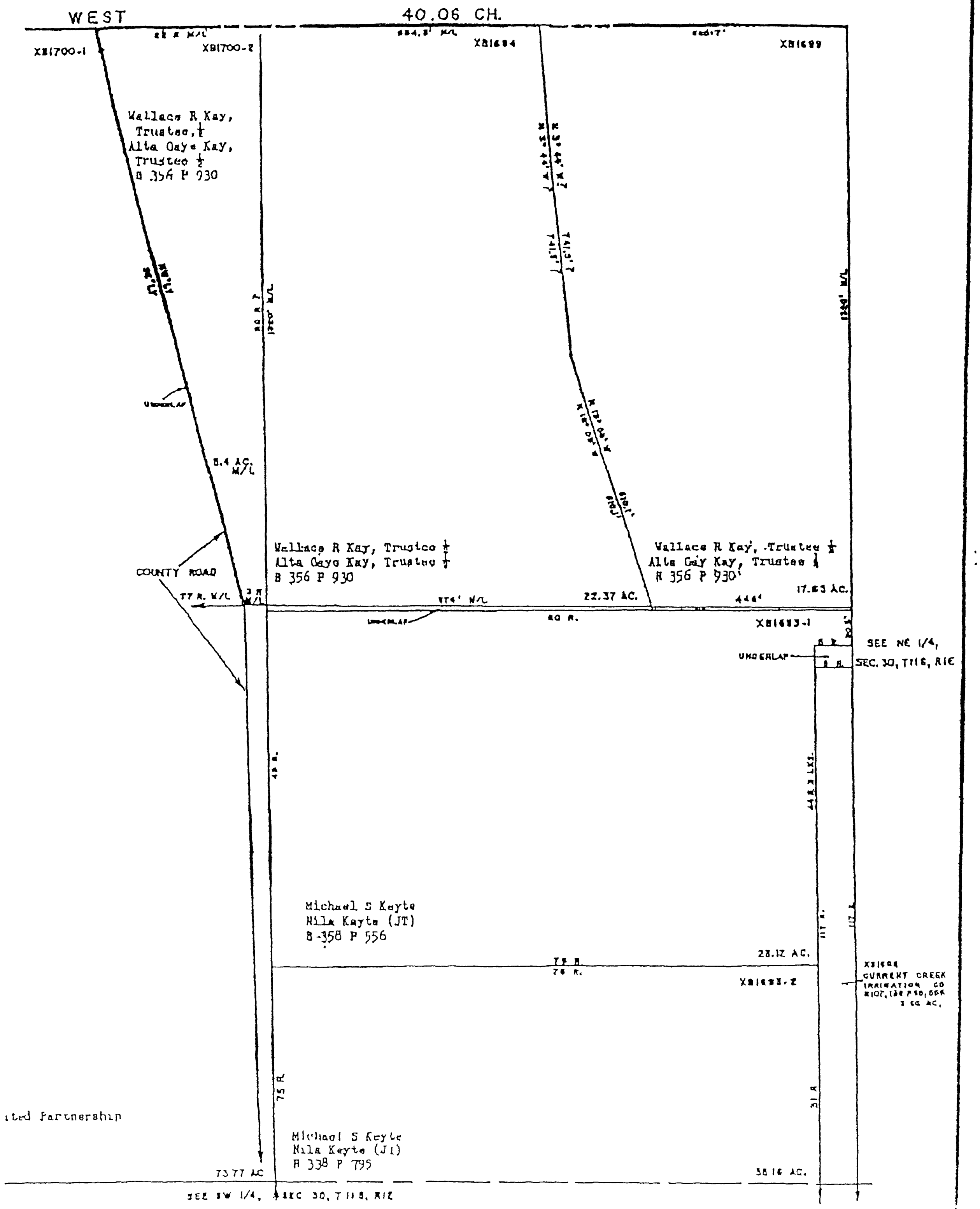
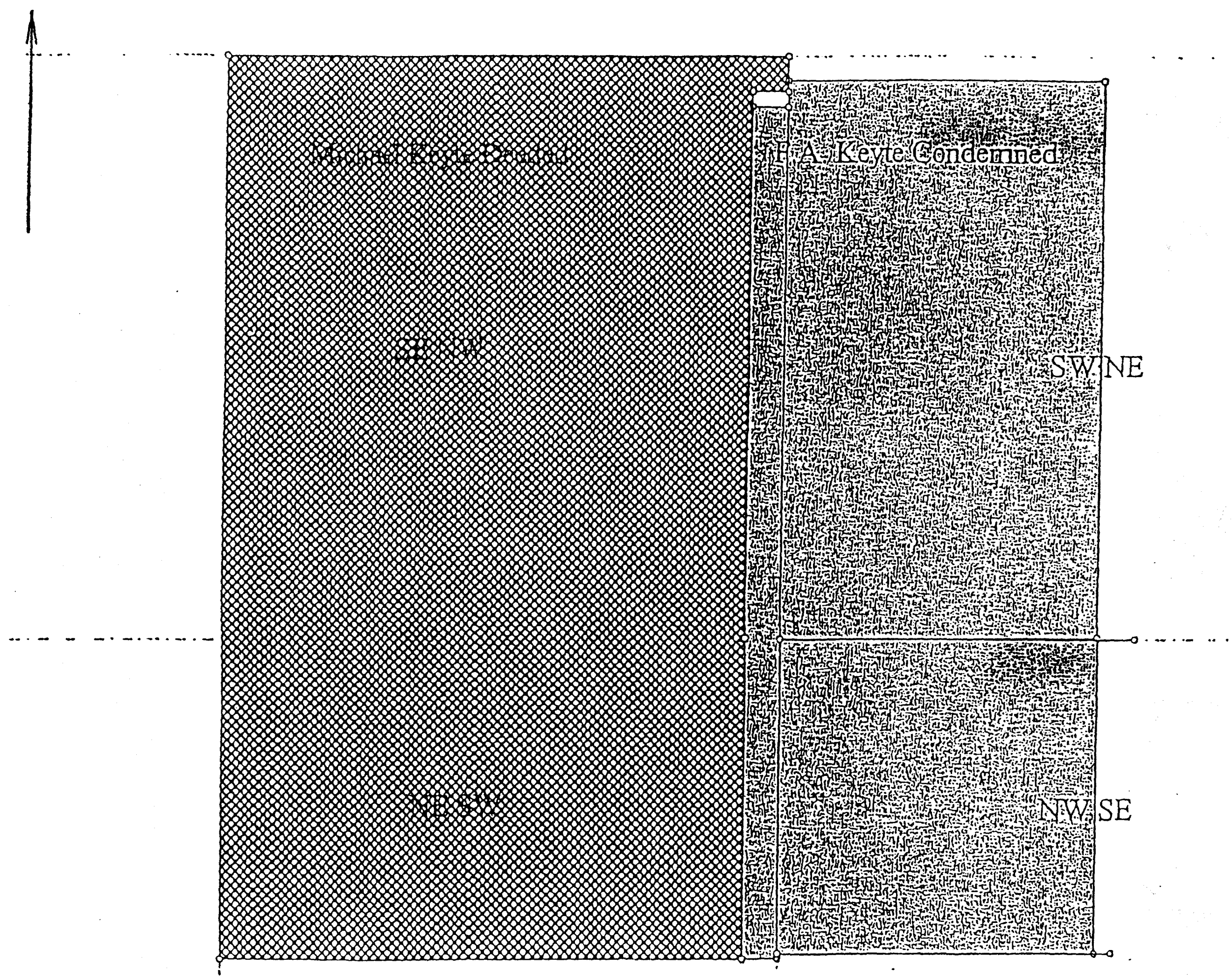


EXHIBIT "F"



Title:	Date: 09-10-2002
Scale: 1 inch = 400 feet	File: MergedUtahLakevKeyteParcels.des

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Tract 3: 22.652 Acres: 986728 Sq Feet: Closure = s90.0000e 89.10 Feet: Precision =1/46: Perimeter = 4093 Feet
Tract 4: 3.656 Acres: 159266 Sq Feet: Closure = n00.0000e 0.00 Feet: Precision >1/999999: Perimeter = 4026 Feet
Tract 5: 58.247 Acres: 2537226 Sq Feet: Closure = s00.0000w 2.20 Feet: Precision =1/3059: Perimeter = 6730 Feet
Tract 6: 12.100 Acres: 527064 Sq Feet: Closure = s88.4506e 0.00 Feet: Precision >1/999999: Perimeter = 2904 Feet

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031=s00.0000w 718.12
032=n90.0000w 736.00
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034=n89.4119e 736.01

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Holme Roberts & Owen LLP

Privileged and Confidential
Attorney Work-Product

MEMORANDUM

To: **Mr. David Graeber**

From: **Jody L. Williams and Steven J. Vuyovich**

Date: **September 30, 2002**

Re: **R. Blake Garrett Water Right**

INTRODUCTION

The following Memorandum addresses the issues pertaining to the due diligence undertaken for Water Right No. 53-97 (A26780) which is the subject of the Option and Purchase Agreement executed between Spring Canyon Energy, L.L.C. and R. Blake Garrett on August 5, 2002 (the "Water Right"). Based upon the records available in the file for the Water Right at the Utah Division of Water Rights, and a preliminary title report and conveyance documents supplied to us for Mr. Garrett by First American Title Company of Fillmore, Utah, the Water Right is owned by R. Blake Garrett.

The Water Right is a perfected Application to Appropriate which is evidenced by Certificate No. 11837 (the "Certificate"). The Certificate was issued in the name of R. Blake Garrett and allows the diversion of 3 cfs of water with a priority date of March 25, 1955 from an underground water well located N 1354 feet and W 48 feet from the S1/4 corner of Section 31, T 12S, R 1E, SLBM. The Water Right is used with 70 shares of Nephi Irrigation Company water to irrigate 107 acres as follows: 17 acres in the NW1/4 of the NW 1/4 and 10 acres in the SW1/4 of the NW 1/4 all in Section 31, T 12S, R 1E, SLBM; and 40 acres in the SE1/4 of the NE 1/4 and 40 acres in the SW1/4 of the NE1/4 all in Section 36, T 12S, R 1W, SLBM (see the attached Exhibit "A"). The sole supply of the Water Right is limited to the irrigation requirements of 96 acres which is quantified as the maximum diversion of 384 acre feet of water annually. The water may be used for irrigation from April 1 to October 31 of each year. The Water Right is discussed in more detail below.

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DISCUSSION

The application was originally filed by Herbert H. Winn on March 25, 1955, for the irrigation of 160 acres located in the NW1/4 of Section 25, T 12S, R 1W, SLBM from April 1 to October 31 of each year and incidental stockwatering from January 1 to December 31 of each year. A flow of 5 cfs of water was to be diverted from a 16 inch underground water well to supply the beneficial uses set forth in the application. The application was approved by the Utah State Engineer ("State Engineer") on May 13, 1960 and proof of beneficial use was first due on October 31, 1961. A Statement of Water User's Claim for the General Determination of Rights in the Utah Lake and Jordan River drainage was filed by Mr. Winn in the Third Judicial District Court of Salt Lake County on November 19, 1971.

Seven Applications for Extension of Time in which to Submit Proof of Beneficial Use ("Extension Requests") were filed by Mr. Winn between May 13, 1960 and May 13, 1974. The State Engineer granted all seven Extension Requests. The last Extension Request was granted to October 31, 1977.

A Segregation Application (Water Right No. 53-596 (A26780)) was filed in the name of Fenton Broadhead on March 23, 1977 and 2 cfs of the 5 cfs of water approved under the Water Right was segregated from the Water Right on June 22, 1977, leaving 3 cfs of water in the original Water Right.

The remaining 3 cfs of the Water Right was assigned to R. Blake Garrett on October 17, 1977, who filed Change Application No. a8787 to change the point of diversion and place of use of the water. An eighth Extension Request filed by Blake Garrett was granted until October 31, 1979.

Blake Garrett filed a Statement of Water User's Claim in his name in the Third Judicial District Court of Salt Lake County for the General Determination of Water Rights in the Utah Lake and Jordan River drainage on October 15, 1979, replacing the Water User's Claim filed by Mr. Winn.

The final corrected Proof of Beneficial Use for the permanent change application filed by Blake Garrett was submitted to the Division of Water Rights on November 8, 1982, and Certificate No. 11837 was issued on November 24, 1982 for the supplemental irrigation of 107 acres. The issuance of a certificate is the final step in completing an appropriation of water under Utah law and is the evidence that a water right has been perfected.

Under Utah law, an *approved* water right application may be conveyed by assignment or by deed. A *perfected* water right application is conveyed by deed as real property. Generally, an appurtenant water right is conveyed with the land unless the water right is specifically reserved by the grantor in the deed.

Based upon a preliminary title report supplied by First American Title Company of Fillmore, Utah which is attached to this Memorandum as Exhibit "B," five parcels of land in Sections 31 and 36 of T 12S, R 1E, SLBM are owned by the following individuals and entities: R. Blake Garrett and Susan K. Garrett, husband and wife, as joint tenants as to Parcel 1; Nephi City, a municipal corporation, as to Parcel 2; Roscoe R. Garrett as to Parcel 3; Nephi City, a municipal corporation, as to Parcel 4; and R. Blake Garrett and Susan K. Garrett, as joint tenants, as to Parcel 5. See the attached Exhibit "C" for a visual representation of the five parcels.

Based upon the Certificate, the Water Right is used to irrigate 17.698 acres in Parcel 3; 9.302 acres in Parcel 4; and 80 acres in Parcel 5. Based upon the deeds supplied to us by First American Title Company of Fillmore, Utah, Roscoe R. Garrett and Aleen L. Garrett received title to Parcels 3, 4 and 5 by general warranty deed on September 22, 1965; R. Blake Garrett and Susan K. Garrett received title to Parcel 5 by general warranty deed from Roscoe R. Garrett on April 7, 1978; and Nephi City, a municipal corporation, received title to Parcel 4 by general warranty deed on October 15, 2001. As set forth above, R. Blake Garrett was assigned the Water Right application on October 17, 1977. There were no reservations of water in the deed conveying Parcel 5 from Roscoe R. Garrett to R. Blake Garrett and Susan K. Garrett; therefore, even if the Water Right was appurtenant to Parcel 5 and Roscoe R. Garrett could prove he owned an interest in the Water Right at the time of the conveyance, the interest to any water used to irrigate Parcel 5 would have been conveyed to R. Blake Garrett and Susan K. Garrett with the land in that deed. Blake Garrett has never owned Parcels 3 and 4. These parcels were owned by Roscoe R. Garrett at the time the proof was filed on the Water Right. Based upon the documents we have reviewed, Roscoe R. Garrett has never owned an interest in any portion of the Water Right; therefore, unity of title between the owners of the land and the Water Right has never existed in connection with Parcels 3 and 4 and Roscoe R. Garrett

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could not legally pass title to any portion of the Water Right.[1] Despite this fact, Roscoe R. Garrett reserved any and all appurtenant water in the deed conveying Parcel 4 to Nephi City and therefore, Nephi City can have no possible claim of ownership to any portion of the Water Right.

On February 24, 1984, a deed of trust was executed by R. Blake Garrett and Susan Kay F. Garrett in favor of the Federal Land Bank of Sacramento covering the right to use 2.4 cfs of water under Water Right for the irrigation of 80 acres in the South 1/2 of the NE1/4 of Section 36, T 12S, R 1E, SLBM (Parcel 5). On March 29, 1989, the Western Farm Credit Bank (formerly the Federal Land Bank of Sacramento) released and reconveyed to R. Blake Garrett and Susan Kay F. Garrett all of the interest formerly acquired by the trust deed. On February 24, 1989, R. Blake Garrett and Susan Kay Garrett aka Susan Kay F. Garrett executed a Trust Deed with Valley Bank and Trust Company as trustee and beneficiary using the entire Water Right as collateral to secure a loan in the amount of $179,012.91. The Water Right was assigned to Bank One, Utah (formerly Valley Bank and Trust) and a security agreement was executed in the name of Bank One, Utah on September 15, 1993.

Don Jones leased all of the water which may be diverted under the Water Right during the 1985 and 1988 irrigation seasons. An Application for Temporary Change ("Temporary Change") was filed and approved on the Water Right for the 1985 irrigation season. The Temporary Change allowed the water to be diverted from a different well to irrigate land in Section 20, T 12S, R 1E, SLBM. The Temporary Change expired on October 30, 1985.

One remaining issue requiring consideration is whether the Water Right has been lost to forfeiture or abandonment. Since all water in the State of Utah is "the property of

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[1] While a perfected water right is appurtenant to its place of use and may be conveyed with the land it is appurtenant to without specific recitation in the conveyance document, for a conveyance of a water right to occur by appurtenance there is one more condition that must be satisfied. That condition is called "Unity of Title." Unity of Title means that the title to the water right and the title to the land are held by the same owner(s)

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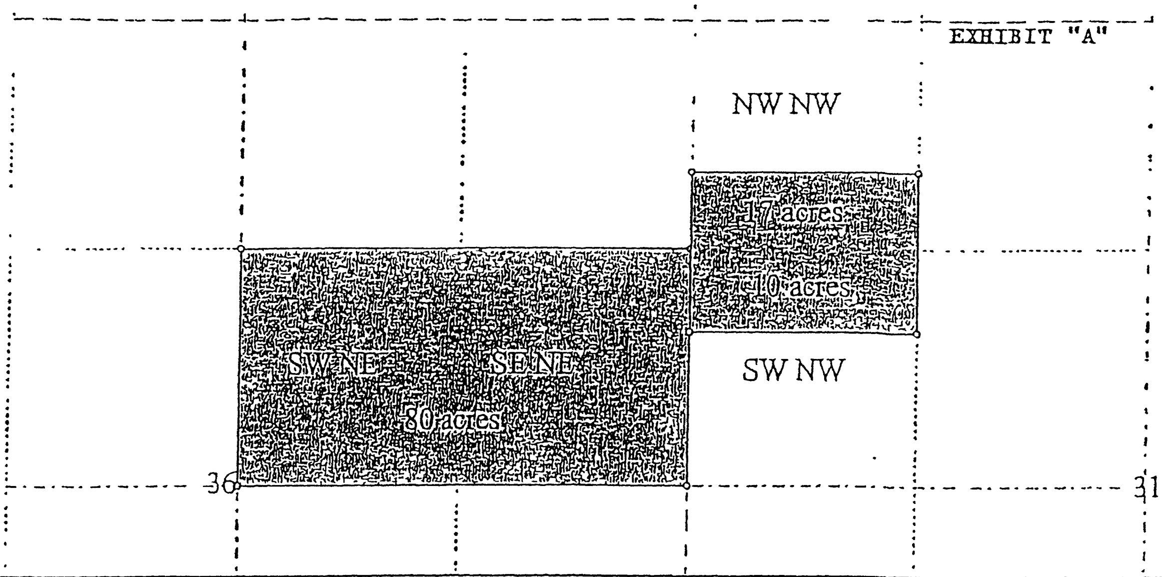
the public," a person holding title to a water right actually owns only the right to the use of water which has been approved for use under the water right, and a failure to continually put that water to beneficial use may result in a loss of a water right to forfeiture or abandonment. Forfeiture is the deprivation or destruction of the right to use water as a result of a failure to put water that was available in priority under the water right to beneficial use. Abandonment is the voluntary relinquishment of a right to use water with the intention of not reclaiming it. Generally, non-use of water under a water right for any five-year period causes the water right to cease and the water to revert to the public, unless an Application for Non-use of Water is filed with the Utah Division of Water Rights and approved by the State Engineer. We have made no independent investigation of the continuous use of the Water Right, although we know of no facts which would lead us to believe the Water Right has been abandoned or forfeited.

As a protection against loss of the Water Right from forfeiture or abandonment, the Water Right Option and Purchase Agreement executed by Spring Canyon Energy, L.L.C. and Blake Garrett contains the following Representation and Warranty by the Seller which is applicable as of the Closing date and which specifically survives the closing date:

> No Forfeiture or Abandonment. The water right is in good standing in the State Engineers Office; the use of the Water Right has been consistent with the water right as on record in the State Engineer's Office; the water right has been used beneficially within the last five (5) years; and neither the water right nor any part, thereof is subject to forfeiture or abandonment for non use.

Based upon the foregoing, we believe the Water Right is in good standing in the Office of the State Engineer and titled in the name of R. Blake Garrett.

EXHIBIT "A"



Title:	Date: 09-10-2002
Scale: 1 inch = 1000 feet	File: Blake GarrettIrrigatedLand.des

Tract 1: 80.000 Acres: 3484800 Sq Feet: Closure = n00.0000e 0.00 Feet: Precision >1/999999: Perimeter = 7920 Feet
Tract 2: 27.000 Acres: 1176120 Sq Feet: Closure = n00.0000e 0.00 Feet: Precision >1/999999: Perimeter = 4422 Feet

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002=/N00E 3960.00	007=N90E 2640.00	012=s0w 54p
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EXHIBIT "B"

Form No. 1344-A (1982)
Plain Language Commitment

SCHEDULE A

ORDER/REFERENCE NO.: 00147327

ESCROW/CLOSING INQUIRIES should be directed to your Escrow officer: Rob Sherman (152), (435) 743-6213. Located at 90 North Main, Fillmore, UT 84631.

1. Effective Date: August 27, 2002 at 7:00 a.m.

2. Policy or Policies to be issued: NONE

3. The estate or interest in the land described or referred to in this commitment and covered herein is fee simple and title thereto is at the effective date hereof vested in:

R. BLAKE GARRETT AND SUSAN KAY F. GARRETT,
Husband and wife, as joint tenants,
As to PARCEL 1,

NEPHI CITY,
A Municipal Corporation Of The State Of Utah,
As to PARCEL 2,

ROSCOE R. GARRETT,
As to PARCEL 3,

NEPHI CITY,
A Municipal Corporation,
As to PARCEL 4,

R. BLAKE GARRETT AND SUSAN KAY F. GARRETT,
Husband and wife, as joint tenants,
As to PARCEL 5

9898.

Form No. 1344-A (1982)
ALTA Plain Language Commitment

Order No. 00147327

4. The land referred to in this commitment is situated in the County of Juab, State of UTAH, and is described as follows:

PARCEL 1: Beginning at the Northwest corner of Section 31, Township 12 South, Range 1 East, Salt Lake Base and Meridian; thence East 80 rods; thence South 54 rods; thence West 80 rods; thence North 54 rods, more or less, to the point of beginning. (XB-2034-1)

LESS THE FOLLOWING: Beginning at a point North 89°49'39" East 885.65 feet along the Section line from the Northwest corner of Section 31, Township 12 South, Range 1 East, Salt Lake Base and Meridian; thence North 89°49'39" East 438.96 feet along the Section line to the Northeast corner of the Northwest quarter of the Northwest quarter of Section 31; thence South 0°01'29" East 894.99 feet along the East line of the Northwest quarter of the Northwest quarter; thence South 90°00'00" West 443.92 feet; thence North 0°17'35" East 893.68 feet, more or less, to the point of beginning.

EXCEPTING THEREFROM all coal, oil, gas and all other minerals.

PARCEL 2: Beginning at a point North 89°49'39" East 885.65 feet along the Section line from the Northwest corner of Section 31, Township 12 South, Range 1 East, Salt Lake Base and Meridian; thence North 89°49'39" East 438.96 feet along the Section line to the Northeast corner of the Northwest quarter of the Northwest quarter of Section 31; thence South 0°01'29" East 894.99 feet along the East line of the Northwest quarter of the Northwest quarter; thence South 90°00'00" West 443.92 feet; thence North 0°17'35" East 893.68 feet, more or less, to the point of beginning. (XB-2034-2)

EXCEPTING THEREFROM all coal, oil, gas and all other minerals.

PARCEL 3: Beginning 54 rods South of the Northwest corner of the Northwest quarter of Section 31, Township 12 South, Range 12 East, Salt Lake Base and Meridian; thence East 80 rods; thence South 54 rods; thence West 80 rods; thence North 54 rods, more or less, to the point of beginning. (XB-2035-1)

LESS THE FOLLOWING: Beginning at a point South 0°01'11" East 891 feet along the Section line and North 90°00'00" East 880.77 feet from the Northwest corner of Section 31, Township 12 South, Range 1 East, Salt Lake Base and Meridian; thence North 90°00'00" East 443.92 feet to the East line of the Northwest quarter of the Northwest quarter; thence South 0°01'29" East 907.68 feet along said East line; thence South 90°00'00" West 448.95 feet; thence North 0°17'35" East 907.69 feet, more or less, to the point of beginning.

EXCEPTING THEREFROM all coal, oil, gas and all other minerals.

PARCEL 4: Beginning at a point South 0°01'11" East 891 feet along the Section line and North 90°00'00" East 880.77 feet from the Northwest corner of Section 31, Township 12 South, Range 1 East, Salt Lake Base and Meridian; thence North 90°00'00" East 443.92 feet to the East line of the Northwest quarter of the Northwest quarter; thence South

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0°01'29" East 907.68 feet along said East line; thence South 90°00'00" West 448.95 feet; thence North 0°17'35" East 907.69 feet, more or less, to the point of beginning. (XB-2035-2)

EXCEPTING THEREFROM all coal, oil, gas and all other minerals.

PARCEL 5: The South half of the Northeast quarter of Section 36, Township 12 South, Range 1 West, Salt Lake Base and Meridian. (XC-2881)

EXCEPTING THEREFROM all coal, oil, gas and all other minerals.

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SCHEDULE B - Section 1
Requirements

The following are the requirements to be complied with:

(A) Pay the agreed amounts for the interest in the land and/or the mortgage or deed of trust to be insured.

(B) Pay us the premiums, fees and charges for the policy. In the event the transaction for which this commitment is furnished cancels, the minimum cancellation fee will be $200.00.

(C) Documents satisfactory to us creating the interest in the land and/or the mortgage or deed of trust to be insured must be signed, delivered and recorded.

(D) You must tell us in writing the name of anyone not referred to in this commitment who will get an interest in the land or who will make a loan on the land. We may then make additional requirements or exceptions.

(E) Release(s), reconveyance(s), and/or other instrument(s), acceptable to the company, inculding payment(s) of any amount(s) due, for the purpose of clearing encumbrances shown in Schedule B-2, attached hereto, which are objectionable to the proposed insured.

(F) Other: NONE.

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SCHEDULE B - Section 2
Exceptions

The policy or policies to be issued will contain exceptions to the following unless the same are disposed of to the satisfaction of the Company.

1. Taxes or assessments which are not shown as existing liens by the records of any taxing authority that levies taxes or assessments on real property or by the public records.
2. Any facts, rights, interests or claims which are not shown by the public records but which could be ascertained by an inspection of said land or by making inquiry of persons in possession thereof.
3. Easements, claims of easements or encumbrances which are not shown by the public records.
4. Discrepancies, conflicts in boundary lines, shortage in area, encroachments and any other facts which a correct survey would disclose, and which are not shown by public records.
5. Unpatented mining claims; reservations or exceptions in patents or in Acts authorizing the issuance thereof, water rights, claims or title to water.
6. Any lien, or right to a lien, for services, labor or material theretofore or hereafter furnished, imposed by law and not shown by the public records.
7. Defects, liens, encumbrances, adverse claims or other matters, if any, created, first appearing in the public records or attaching subsequent to the effective date hereof but prior to the date the proposed insured acquires of record for value the estate or interest or mortgage thereon covered by this commitment.

THE FOLLOWING AFFECTS PARCELS 1 AND 2:

8. General property taxes for the year 2002 now a lien, not yet due. Tax ID No.XB-2034-1 AND XB-2034-2.

   2001 general property taxes were paid in the amount of $8.14 AND $0.

9. The effect of the 1969 Farmland Assessment Act, wherein there is a five (5) year roll-back provision with regard to assessment and taxation, by reason of that certain Application for Assessment and Taxation of Agricultural Land.

10. Subject to Easements and right-of-ways of record or enforceable in law and equity.

11. The right, privilege, and authority given to The Mountain States Telephone and Telegraph Company to construct, operate, and maintain its lines of Telephone and Telegraph, including the necessary pole, wires and fixtures upon. over and across the property herein, by instruments dated February 12, 1947 and recorded on March 25, 1947 in Book 132 at page 527 of the records of Juab County, Utah.

12. A Conveyance of Easement granted to NEPHI IRRIGATION COMPANY, for the placement, construction, use, operation, repair, replacement, inspection, and maintenance of a water conveyance and distribution system and appurtenant works, recorded AUGSUT 26, 1999 as Entry No. 217938 in Book 405 at page 758 of Official Records.

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13. SUBJECT to the County Road right of way.

THE FOLLOWING AFFECTS PARCELS 3 AND 4:

14. General property taxes for the year 2002 now a lien, not yet due. Tax ID No.XB-2035-1 AND XB-2035-2

2001 general property taxes were paid in the amount of $8.14 AND $0.

15. The effect of the 1969 Farmland Assessment Act, wherein there is a five (5) year roll-back provision with regard to assessment and taxation, by reason of that certain Application for Assessment and Taxation of Agricultural Lanc.

16. Subject to Easements and right-of-ways of record or enforceable in law and equity.

17. *Right of ways, easements, roadways, power lines, ditches, canals, pipelines, encroachmenst and* conflicts in boundary lines or other lines or other items which could be dtermined by and inspection and/or on accurate survey of property herein.

18. The right, privicge and authority given to The Mountain States Telephone and Telegraph Company to construct, operate and maintain its lines of Telephone and Telegraph, including the necessary pole, wires and fixtures upon, over and across the property herein, by instruments dated February 27, 1947; and recorded on March 25, 1947, in Book 132 at page 537 of the records of Juab County, Utah.

19. A right of way and easement, for utility use, as granted to NEPHI CITY, A MUNICIPAL CORPORATION by Instrument recorded APRIL 7, 1987 as Entry No. 184302 in Book 325 at page 839 of Official Records.

20. A Right of way and easement conveyed unton NEPHI CITY, A MUNICIPAL CORPORATION, for utility use, and particularly for: A. Digging a trench or trenches across said right of way, to lay, maintain, operate, repair, remove and replace pipelines, valves, gates and gate boxes, for the transporation of sewage through and across property herein 10 feet on each side of the followin described cetner line: Beginning at a point which lies South 1754.22 feet and east 31.72 feet from the Nrothwest corner of Section 31, Township 12 South, Range 1 East, Salt Lake Base and Meridian; thence North 89°16'46" East 307.90 feet along the North 20 feet property herein. Recorded on December 10, 1996 as Entry No. 208971, in Book 381 at page 103 of the records of Juab County, *Utah.*

21. A Conveyance of Easement granted to NEPHI IRRIGATION COMPANY, for the placement, construction, use, operation, repair, replacement, inspection, and maintenance of a water conveyance and distribution system and appurtenant works, recorded AUGSUT 26, 1999 as Entry No. 217938 in Book 405 at page 758 of Official Records.

22. SUBJECT to the County Road right of way.

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THE FOLLOWING AFFECTS PARCEL 5:

23. General property taxes for the year 2002 now a lien, not yet due. Tax ID No.XC-2881.

    2001 general property taxes were paid in the amount of $168.73.

24. The effect of the 1969 Farmland Assessment Act, wherein there is a five (5) year roll-back provision with regard to assessment and taxation, by reason of that certain Application for Assessment and Taxation of Agricultural Land.

25. Subject to Easements and right-of-ways of record or enforceable in law and equity.

26. The right, priviege and authority given to The Mountain States Telephone and Telegraph Company to construct, operate and maintain its lines of Telephone and Telegraph, including the necessary pole, wires and fixtures upon, over and across the property herein, by instruments dated February 27, 1947, and recorded on March 25, 1947, in Book 132 at page 537 of the records of Juab County, Utah.

27. A right of way and easement for distribution, appurtenant facilities and incidental purposes, as granted to UTAH WATER AND POWER BOARD by Instrument recorded MAY 22, 1954 as Entry No. 86988 in Book 158 at page 347 of Official Records.

28. A right of way and easement for digging a trench or trenches across said right of way, to lay, maintain, operate, repari, remove, and replace pipelins, valves, gates and gate boxes for the transportation of sewage through and across the hereinafter described property, as granted to NEPHI CITY, A MUNICIPAL CORPORATION by Instrument recorded APRIL 7, 1987 as Entry No. 184303 in Book 325 at page 841 of Official Records.

29. SUBJECT to the County Road right of way.

* * *

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NOTE: The names of R. BLAKE GARRETT, SUSAN KAY F. GARRETT, AND ROSCOE R. GARRETT, have been checked for Judgments and Tax Liens, etc., in the appropriate offices and if any were found would appear as Exceptions to title under Schedule B, Section 2 herein.

Title inquiries should be directed to GARY DAY (435) 283-4900.

* * *

NOTE: The policy (ies) to be issued as a result of this Commitment contain an Arbitration Clause set forth in the Conditions/Conditions and Stipulations Section. The following is included for the information of the proposed insured(s):

Any matter in dispute between you and the company may be subject to arbitration as an alternative to court action pursuant to the rules of the American Arbitration Association or other recognized arbitrator, a copy of which is available on request from the company. Any decision reached by arbitration shall be binding upon both you and the company. The arbitration award may include attorney's fees if allowed by state law and may be entered as a judgment in any court of proper jurisdiction.

* * *

Exceptions 1-7 will be omitted on lenders policy

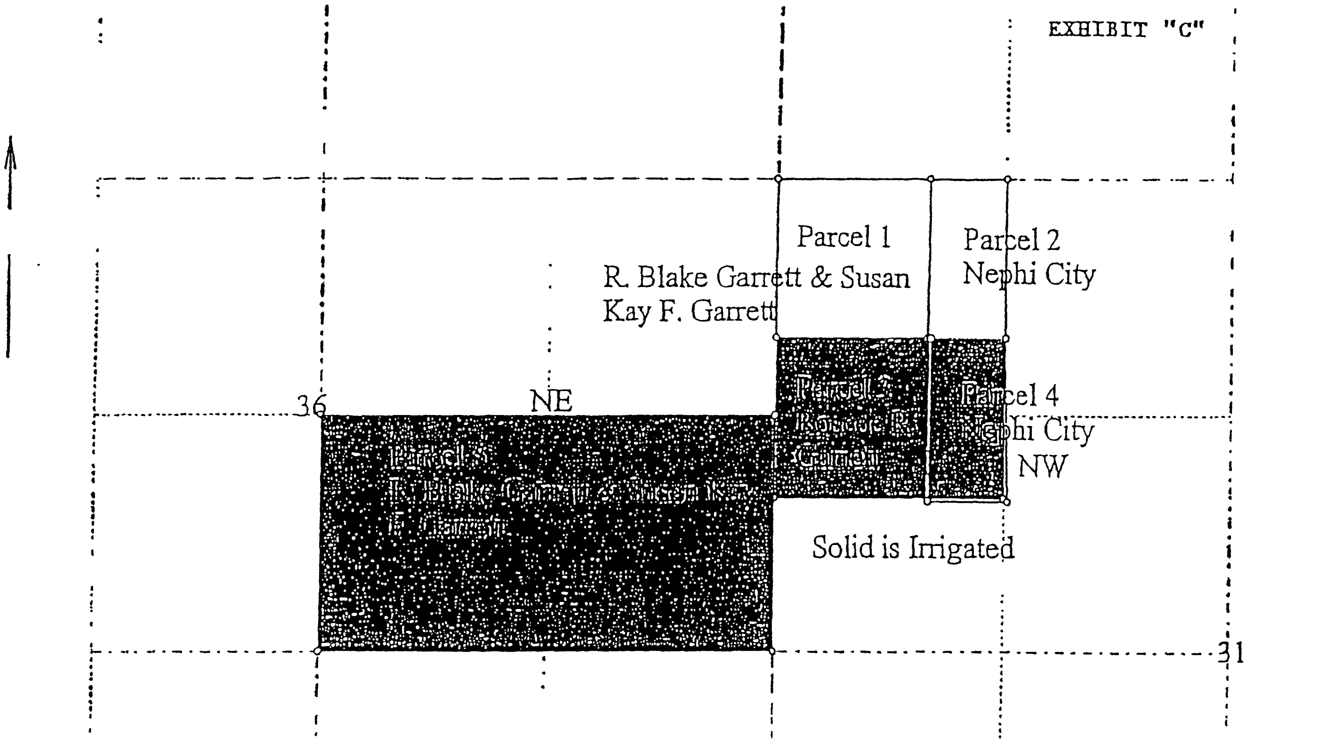
* * *

In the event the transaction for which this commitment was ordered "cancels", please refer to paragraph b under Schedule B, Section 1 for required cancellation fee.

* * *

tgf
8/2002

EXHIBIT "C"



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-Tract 2: 9.063 Acres: 394790 Sq Feet: Closure = n89.3527e 0.00 Feet: Precision =1/550277: Perimeter = 2672 Feet
Tract 3: 27.000 Acres: 1176120 Sq Feet: Closure = n00.0000e 0.00 Feet: Precision >1/999999: Perimeter = 4422 Feet
-Tract 4: 9.302 Acres: 405201 Sq Feet: Closure = s89.2855w 15.85 Feet: Precision =1/171: Perimeter = 2708 Feet
Tract 5: 80.000 Acres: 3484800 Sq Feet: Closure = n00.0000e 0.00 Feet: Precision >1/999999: Perimeter = 7920 Feet
Net Area= 8.635 Acres: 376129 Sq Feet

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009=s0.0129e 894.99	021=/n90.0000e 880.77	033=N90E 2640.00
010=s90.0000w 443.92	022=n90.0000e 443.92	
011=n0.1735e 893.68	023=s01.0129e 907.68	
012=@0 Merge 1	024=s90.0000w 448.95	

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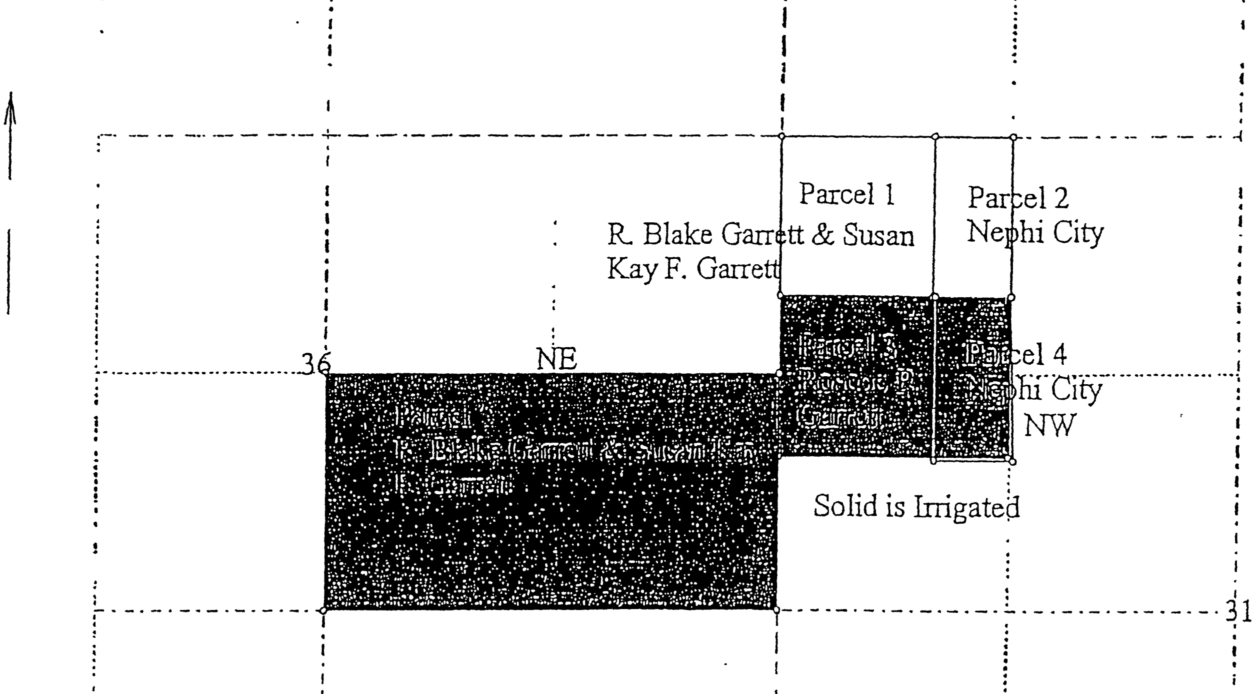
EXHIBIT "C"



Title:	Date: 09-10-2002
Scale: 1 inch = 1000 feet	File: BlakeGarrettParcel1-5.des

+Tract 1: 27.000 Acres: 1176120 Sq Feet: Closure = n00.0000e 0.00 Feet: Precision >1/999999: Perimeter = 4422 Feet
-Tract 2: 9.063 Acres: 394790 Sq Feet: Closure = n89.3527e 0.00 Feet: Precision =1/550277: Perimeter = 2672 Feet
Tract 3: 27.000 Acres: 1176120 Sq Feet: Closure = n00.0000e 0.00 Feet: Precision >1/999999: Perimeter = 4422 Feet
-Tract 4: 9.302 Acres: 405201 Sq Feet: Closure = s89.2855w 15.85 Feet: Precision =1/171: Perimeter = 2708 Feet
Tract 5: 80.000 Acres: 3484800 Sq Feet: Closure = n00.0000e 0.00 Feet: Precision >1/999999: Perimeter = 7920 Feet
Net Area= 8.635 Acres: 376129 Sq Feet

001=/nw,31,12s,1e	013=/nw,nw,31,12s,1e	025=n0.1735e 907.69
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011=n0.1735e 893.68	023=s01.0129e 907.68	
012=@0 Merge 1	024=s90.0000w 448.95	

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C. Water Rights Option and Purchase Agreements

WATER RIGHT OPTION AND PURCHASE AGREEMENT

THIS WATER RIGHT OPTION AND PURCHASE AGREEMENT ("Agreement") is entered into as of the 14th day of August, 2002, by and between MICHAEL S. KEYTE, whose mailing address is P.O. Box 274, Mona, UT 84645 ("Seller") and SPRING CANYON ENERGY, L.L.C., a Utah limited liability company whose mailing address is P.O. Box 774000, #359, Steamboat Springs, CO 80477 ("Buyer"). The Seller and Buyer are referred to collectively in this Agreement as the "Parties."

RECITALS

A. Seller owns Water Right No. 53-1431, Application No. D6919 and approved Change Application No. a21754 (the "Water Right") and desires to sell the Water Right to Buyer. Seller represents that the Water Right has been quantified by the Utah State Engineer's Office ("State Engineer") as yielding 163.22 acre feet annually.

B. Buyer desires to purchase the Water Right from Seller for industrial use at a facility (the "Facility") to be constructed according to the following terms and conditions. Seller desires to sell the Water Right to Buyer under the same terms and conditions.

C. Buyer and Seller entered into a Water Right Option and Purchase Agreement on May 30, 2002 for the Water Right. The Parties desire that this Agreement replace and supersede the May 30, 2002 Water Right Option and Agreement in its entirety.

AGREEMENT TERMS

In consideration of the mutual promises, covenants, and conditions of this Agreement, the Parties agree as follows:

1. Option to Purchase. Seller hereby sells, gives and grants to Buyer, and its assigns, the exclusive option to purchase (the "Option"), for the price hereinafter set forth, all of Seller's right, title, estate and interest in and to the Water Right. The Option becomes effective when this Agreement has been signed by the Parties and the Initial Option Fee provided for in Section 2 has been deposited with the escrow agent designated in Section 4 below (the "Escrow Agent").

1.1. Purchase Price. The price to be paid for the Water Right shall be Four Thousand Dollars ($4,000 00) for each acre-foot presently approved for diversion under the Water Right, for a total purchase price of Six Hundred Fifty-Two Thousand Eight Hundred Eighty Dollars ($652,880.00) (the "Purchase Price").

2. Consideration for Option. As consideration for the Option, Buyer shall pay to Seller Six Thousand Five Hundred Twenty-Eight and Eighty Hundredths Dollars ($6,528.80) as the

initial option fee (the "Initial Option Fee"). If Buyer elects to extend the Option beyond the initial 6-month period, Buyer shall make the additional Option payments for each extension as further described herein.

2.1. The Buyer shall within 10 days from the date this Agreement is signed by the Parties deposit the Initial Option Fee in escrow in an interest-bearing account to be held by the Escrow Agent. The Initial Option Fee, together with all accrued interest thereon, shall be released to Seller and become non-refundable to Buyer upon Buyer's written notice to Seller and Escrow Agent that all of the conditions precedent set forth in Sections 7.1 through 7.6 of this Agreement have been satisfied. The Initial Option Fee is in addition to, and shall not be credited against, the Purchase Price.

2.2. Buyer may extend the Option for up to 36 months from the date the Parties sign this Agreement by depositing an additional Option payment with the Escrow Agent in the amount of Six Thousand Five Hundred Twenty-Eight and Eighty Hundredths Dollars ($6,528.80) (a "Deposit") for each six (6) months that Buyer elects to extend the Option, and by giving notice as set out in Section 3. The first such Deposit shall be made, if at all, within six months from the date Seller executes this Agreement. Each time Buyer elects to extend the Option period, as further provided in Section 3, Buyer shall, within six (6) months of the previous Deposit, deliver another Deposit to the Escrow Agent. Each Deposit shall be paid into the interest-bearing escrow account established by the Escrow Agent and administered by it in conformance with the terms and provisions of this Agreement. For example, if the Initial Option Fee was deposited into Escrow on August 1, 2002 and Buyer thereafter gives written notice of an election to extend this Option, Buyer must give the notice as provided in Section 3 and deliver a Deposit to the Escrow Agent on or before the first business day after February 1, 2003. If the Option is again extended, another Deposit must be delivered to the Escrow Agent on or before August 1, 2003.

2.3. If Buyer exercises its Option as hereinafter provided, the principal amount of the Deposits, together with all accrued interest thereon, shall be credited to the Purchase Price.

3. Period of Option and Extension. The initial period of duration of this Option is six (6) months from the date the Parties sign this Agreement (the "Option Period"). At any time during the Option Period, Buyer has the right to exercise its Option to purchase the Water Right or, at its sole discretion, terminate the Option. The Option Period may be extended in accordance with the following:

3.1. At the end of the initial Option Period, Buyer may elect to extend the Option for additional six (6) month periods upon written notice to Seller and payment of a Deposit in the same amount and frequency as described in Section 2.2 hereof for each additional six-month period.

3 2. If Buyer elects to extend the Option, it shall provide Seller with written notice of its intention no later than ten (10) days prior to the expiration of the Option period together with payment of the required Deposit to the Escrow Agent as set forth in Section 2.2. Buyer shall pay an additional Deposit for each six (6) month period that Buyer elects to extend the Option.

3.3. Buyer may extend the Option to a maximum of thirty-six (36) months. The Option shall expire upon failure of Buyer to extend the Option strictly on the terms set out in this Agreement, upon expiration of 36 months from the date the Parties sign this Agreement, or upon exercise of the Option by Buyer, whichever occurs first.

4. Escrow Agent and Opening of Escrow. The parties hereby designate Juab Title and Abstract Company of 240 North Main Street, P.O. Box 246, Nephi, Utah 84648[1] as the Escrow Agent and closing agent for all purposes under this Agreement. Buyer shall, within 10 days from the date this Agreement is signed by the Parties deposit the Initial Option Fee with the Escrow Agent and deliver an executed copy of this Agreement to the Escrow Agent.

5. Alienation of Interests; Encumbrances; Leases. As further consideration for the sum paid for this Option, Seller shall not sell, convey, or otherwise encumber the Water Right, in any way, during the Option Period and if applicable, any additional extension(s). Seller further agrees that he will not lease the Water Right or any part thereof during either the Option Period or any extension of the Option Period without first securing the written approval of the Buyer.

5.1. Notice of Default; Trustee's Sale; Repossession; Foreclosure; Civil Litigation. In the event of any notice of default, trustee's sale, repossession, foreclosure, civil litigation or other action to enforce a lien or encumbrance against the Water Right, Buyer may take any reasonable steps necessary to prevent or forestall such action if such action would impair Buyer's rights under this Agreement. Such action by Buyer may include, but shall not be limited to, directing that any portion of the Initial Option Fee or any Deposit(s) paid into escrow may be paid to any lienholder or creditor initiating action against Seller or the Water Right. Any amounts paid by Buyer on behalf of Seller under this Section may be offset against the Purchase Price, at Buyer's election.

6. Right of Entry. During the Option Period or any applicable extension, Seller shall permit Buyer, its employees and agents, to enter upon the property of Seller to complete its due diligence or to perform other work connected to the Water Right or the filing of a permanent change application.

7. Conditions Precedent. Sections 7.1 through 7.6 shall be express conditions precedent to the release of the Initial Option Fee, except that completion of Buyer's obligations under Section 7.3 shall not be a condition precedent to release of the Initial Option Fee.

7.1. The Initial Option Fee shall be placed into escrow with the Escrow Agent for up to a sixty (60) day due diligence period during which Buyer will investigate and confirm the nature of the Water Right (the "Due Diligence Period"). To assist Buyer in the Due Diligence Period, Seller shall, within two weeks of the execution of this Agreement, deliver at his expense, a preliminary title report, together with legible copies of all documents referred to therein, including, but not limited to, the real property that is shown as the place of use of the Water Right in the records of the State of Utah, Division of Water Rights. If, prior to the end of the

[1] Items should be sent to the attention of Mary Lou Sperry. Telephone number: (435)623-0387. Email: juabtitle@nebonet.com

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Due Diligence Period, Buyer objects to the nature, sufficiency, or title to the Water Right, Seller shall have up to sixty (60) days after written notice to cure said deficiency. During such cure period, the Initial Option Fee shall continue to be held in escrow. If deficiencies are not cured by the end of the cure period or such additional time as may be approved by Buyer, the Initial Option Fee shall be returned to Buyer and this Agreement shall terminate.

7.2. Seller shall file with the State Engineer a permanent change application as provided for under Utah Code Annotated § 73-3-3 seeking authorization for the Water Right to be diverted from Buyer's proposed underground water well(s) and used at Buyer's Facility to be constructed in the NE¼ of the SE¼ of Section 23, Township 11 South, Range 1 West, SLBM or such other location within the Utah Lake basin upstream of Mona Dam specified by Buyer (the "Change Application"). In this regard, the Parties are obligated as follows:

(a) As soon as possible following the execution of this Agreement, but in no case later than August 15, 2002, or such later date as may be approved by Buyer, Seller shall prepare and file the Change Application with the State Engineer to facilitate Buyer's intended use of the Water Right by Buyer. The Change Application shall show Buyer as the co-applicant and shall be filed at the sole expense of Buyer. It is anticipated that the approved Change Application will be conveyed by the same deed conveying the Water Right at closing.

(b) Seller shall throughout processing of the Change Application give good faith cooperation and assistance to Buyer regarding the Change Application. Such good faith assistance and cooperation shall be a continuing obligation under this Agreement, but shall not be a condition precedent to release of the Initial Option Fee.

7.3. Documents evidencing Seller's and Buyer's authority, including powers of attorney, if needed, and such other evidence, as required, of Seller's and Buyer's authority to consummate the transaction contemplated herein.

7.4. Delivery by Seller to the Escrow Agent of a duly executed and acknowledged Water Right Deed, in the form attached hereto as Exhibit "A," conveying title to the Water Right and Change Application to Buyer and any and all other documentation reasonably required by Buyer's counsel to consummate this transaction. Such delivery shall be a conditional delivery conditioned upon Buyer's exercise of the Option and completion of closing as set out in this Agreement.

7.5. Execution and delivery to the Escrow Agent by the Parties of a Memorandum of Water Right Option in substantially the form attached hereto as Exhibit "B" and recordation of said Memorandum in the office of the Juab County Recorder of Juab County, Utah.

7.6. Delivery to the Escrow Agent of any approvals of this Agreement required by the holder of any lien or encumbrance against the Water Right.

7.7. If the conditions precedent set forth in Sections 7.1 through 7.6 have been reasonably satisfied, Buyer shall notify Seller and the Escrow Agent of such in writing and the

Initial Option Fee shall become non-refundable to Buyer at that time. The non-refundable Initial Option Fee shall then be released to Seller.

8. Water Rights Approvals. Buyer's use of the Water Right requires that the State Engineer approve the Change Application provided in Section 7.2. Buyer's use also requires that at least fifty percent (50%), or 81.61 acre feet of the 163.22 acre feet of water presently approved for diversion annually under the Water Right, be approved as depletion under the approved Change Application described in 7.2 hereof. In that regard:

8.1. Seller shall diligently prosecute the Change Application to a final non-appealable approval by either the State Engineer or by the courts on appeal of any decision of the State Engineer. If the State Engineer issues a decision that rejects the Change Application, or approves the Change Application but limits depletion to less than 81.61 acre feet per year, the Buyer may elect to either terminate this Option or to seek judicial review of the State Engineer's decision. The Buyer may also elect to terminate this Agreement if the State Engineer issues a favorable decision (a decision approving the Change Application and designating at least 81.61 acre feet of depletion), but a third party appeals the favorable decision and the appeal is not resolved within 60 days. If a judicial review action is filed by a third party and Buyer does not terminate this Agreement, or if Buyer elects to seek judicial review of a decision from the State Engineer, Buyer shall bear the expense of the judicial review action.

8.2. If the State Engineer approves less than 81.61 acre feet as depletion under said approved Change Application, or if a third party appeals a favorable decision of the State Engineer, Buyer may unilaterally withdraw from this Agreement upon written notice and any Deposits and all interest thereon placed in escrow pursuant to Section 2, (which by definition do not include the Initial Option Fee), shall be immediately refunded to Buyer. Seller shall be entitled to retain the Initial Option Fee if Buyer withdraws under this Section 8.2.

8.3. If Buyer fails to exercise its Option hereunder, Seller may withdraw the Change Application at any time after termination of the Option.

9. Exercise of Option. The Buyer and Seller each shall use their best efforts in accomplishing the conditions precedent in Section 7 and the approval of the Change Application as described in Section 8. If Buyer elects to exercise the Option, the Option shall be exercised by Buyer giving written notice to Seller.

10. Closing of Purchase. If Buyer exercises the Option, the closing of such purchase ("Closing") shall be completed in accordance with this Section. The Parties may also provide additional written instructions if the instructions are consistent with this Agreement. The Parties instruct and authorize the Escrow Agent to close the purchase transaction as directed in this Section and any consistent written instructions provided by the Parties.

10.1. Closing Date. The transaction contemplated herein shall close ninety (90) days from the date that Buyer exercises this Option as set forth in Section 9 above, at the Escrow Agent's office, or at such other time and place as may be mutually agreed upon by the Parties. In no event, however, shall Buyer be obligated to close the transaction unless the conditions

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precedent as set forth in Sections 7.1 through 7.6 herein shall have first been satisfied, and the Change Application approved as provided in Section 8, or if Buyer elects at its sole discretion, for any reason whatsoever, to not exercise the Option and thereby decides to terminate the Agreement. The Closing Date and Closing are terms used herein to mean the date the Purchase Price is paid into escrow and the Water Right Deed and other instruments of conveyance of the Water Right, if necessary, are filed for recordation in the office of the Juab County Recorder, Juab County, Utah.

10.2. Buyer's Closing Deliveries. At the Closing, Buyer shall deliver to Seller the following:

10.2.1. Payment of the balance of the Purchase Price in cash or by certified or cashier's check payable to Seller or Seller's designee, plus Buyer's share of the Closing costs.

10.2.2. The documents evidencing the authority of Buyer to consummate the transaction contemplated herein that were deposited with the Escrow Agent as provided for in Section 7.3.

10.2.3. Any and all other documentation reasonably required by Seller's legal counsel to consummate this transaction.

10.3. Seller's Closing Deliveries. At the Closing, Seller shall deliver to Buyer the following:

10.3.1. The duly executed and acknowledged Water Right Deed deposited with the Escrow Agent prior to disbursement of the Initial Option Fee as provided for in Section 7.4 herein. Such execution and delivery prior to the disbursement of the Initial Option Fee shall be deemed complete delivery by Seller to the Escrow Agent, subject to the provisions of this Section 10, for the purposes of Closing the sale of the Water Right and Change Application. Such execution and delivery shall be deemed irrevocable except upon termination of this Agreement in accordance with the terms hereof. Seller shall nevertheless, if requested by Buyer, execute and deliver at the time of the Closing a good and sufficient Water Right Deed in the form attached hereto as Exhibit "A," conveying title to the Water Right and approved Change Application to Buyer showing any changes as necessary at the time of Closing.

10.3.2. The documents evidencing the authority of Seller to consummate the transaction contemplated herein that were deposited with the Escrow Agent as provided for in Section 7.3.

10.3.3. Any and all other documentation reasonably required by Buyer's and Seller's counsel to consummate this transaction.

10.4. Costs and Expenses. Seller and Buyer shall pay and be responsible for the following costs and expenses:

10.4.1. Seller's Costs Seller shall pay the costs incurred by him for legal, accounting and other consultants' services together with all other costs incurred by Seller in the satisfaction of Seller's obligations under this Agreement, plus one-half of the Escrow Agent's fees and expenses incurred by the Parties in completing the Closing.

10.4.2. Buyer's Costs. Buyer shall pay the costs incurred by it for legal, accounting and other consultants' services, together with all other costs incurred by it in the satisfaction of its obligations under this Agreement, plus one-half of the Escrow Agent's fees and expenses incurred by the Parties in completing the Closing. Buyer shall pay all recordation fees for recording the Memorandum of Water Right Option provided for in Section 7.5 and the Water Right Deed upon Closing.

10.5. Possession. Seller shall cause such reconveyances of trust deed, mortgage releases, cancellation of financing statements, and any other instruments as necessary to represent release of any liens or encumbrances against the Water Right and approved Change Application to be removed prior to Closing, and Buyer shall be entitled to actual and exclusive right and possession of the Water Right and approved Change Application, free of any person or other entity having or claiming any possessory right, title or interest with respect thereto, as of the Closing.

10.6. The Escrow Agent shall record all documents necessary to release liens and encumbrances against the Water Right and approved Change Application; and record the Water Right Deed from Seller to Buyer at the time of Closing.

10.7. The Escrow Agent shall disperse the Purchase Price proceeds first to pay Seller's share of Closing costs, tax prorations and other such Closing Costs; second to retire any liens or encumbrances against the Water Right and Change Application; and third, to Seller or to such persons as Seller designates.

11. Seller's Representations and Warranties. Seller hereby makes the following representations and warranties, (it being understood and agreed by the Parties that all references herein to representations and warranties pertaining to the Water Right itself, and including the Change Application shall be applicable as of the Closing Date) and agrees that such representations and warranties shall survive the Closing:

11.1. Marketable Title. Seller shall have, as of the date of Closing, good and marketable title to the Water Right, subject to no liens, taxes, encumbrances, restrictions or adverse easements or interests of any kind or nature whatsoever.

11.2. No Forfeiture or Abandonment. The Water Right is in good standing in the State Engineer's office; the use of the Water Right has been consistent with the Water Right as on record in the State Engineer's office; the Water Right has been used beneficially within the last five (5) years; and neither the Water Right nor any part thereof is subject to forfeiture or abandonment for non use.

11.3. Authority. Seller and the person executing this Agreement on behalf of Seller have the full right, power and authority to enter into this Agreement and to consummate the transactions contemplated herein.

11.4. Defaults. Seller is not in default in respect of any judgment, order, writ, injunction, decision, law, ordinance or regulation of any court or governmental authority or under any lease, mortgage, or other agreement to which it, or the Water Right, Change Application, or any portion thereof, is or might be subject which might prohibit, delay, or interfere with the consummation of the transaction contemplated hereby or affect the right, title, and interest or the condition of the Water Right and Change Application; and the execution and delivery of this Agreement. Further, the performance by Seller of its obligations hereunder will not (i) result in the breach or termination of or violate or constitute a default under any such lease, mortgage, or other agreement, or (ii) result in the creation or imposition of any lien, charge, or encumbrance upon the Water Right or Change Application or any portion thereof, or (iii) violate any law, regulation, judgment, or order of any governmental entity.

11.5. Documents. All documents delivered to Buyer pursuant hereto are, to the best of Seller's knowledge, true, correct, and complete copies of the original documents. The Water Right and Change Application will not at Closing be subject to any unrecorded instruments affecting the title to or the right to the use of the Water Right for the Buyer's purposes as set forth herein.

11.6. Maintenance Pending Closing. From and after the date of execution hereof and until Closing, Seller shall maintain and manage the Water Right so as to do nothing which might damage the value or condition of the Water Right and Change Application. Seller shall protect the Water Right from forfeiture or abandonment. Seller will not knowingly engage in any conduct that will adversely affect the likelihood of a favorable decision on the Change Application. If necessary to prevent forfeiture or abandonment of the Water Right, at Buyer's sole discretion, Seller will, upon Buyer's request, file an Application for Nonuse of Water on any unused portion of the Water Right.

11.7. Litigation and Claims. Seller has not received any notice of or is otherwise not aware of any claims, actions, suits or other proceedings, whether pending, threatened, or to the best of his knowledge, contemplated by any governmental department or agency or any corporation, partnership or other entity or person whatsoever, or to the best of his knowledge, after due inquiry, any facts which could constitute the basis for any claim or litigation which might prohibit, delay or interfere with the consummation of the transaction contemplated hereby or which, if adversely determined, might affect the right, title and interest which may be acquired by the Buyer in and to the Water Right and Change Application, or the condition or the value of the Water Right and Change Application.

11.8. Available Data. At all reasonable times hereafter, up to and including the Closing, Seller and his accountants, engineers, and agents shall make available to Buyer, its counsel and/or accountants or other consultants, for examination at reasonable times, all reports, studies and all other relevant documents reasonably pertaining to the Water Right and Change Application.

11.9. Water Right. The Water Right has been accurately and completely described in this Agreement. All necessary approvals for use of the Water Right for Seller's present uses have been obtained by or on behalf of Seller and are in full force and effect. The Water Right is titled in Seller's name at the Utah Division of Water Rights.

12. Buyer's Representations and Warranties. In order to induce Seller to execute this Agreement, and to enter in the transaction contemplated hereby, Buyer hereby represents and warrants that:

12.1. Full Power and Authority. Buyer is a limited liability company organized and existing under the laws of the State of Utah and possesses the capability, power, and legal authority to perform all acts and obligations required of it hereunder.

12.2. No Conflict. The execution, delivery, and performance of this Agreement by the Buyer and the consummation of the transactions contemplated herein will not (i) result in a breach or acceleration of or constitute a default or event of termination under the provisions of any agreement or instrument to which Buyer is a party or bound; or (ii) constitute or result in the violation or breach by Buyer of any judgment, order, writ, injunction, or decree issued against or imposed upon Buyer or result in the violation of any applicable law, ordinance, rule or regulation of any governmental authority.

13. Risk of Loss. Risk of loss to the Water Right shall be Seller's until Closing and transfer of title as herein provided, except any loss or reduction, subject to the provisions of Section 8.2 hereof, that occurs as a result of any decision on the Change Application.

14. 1031 Tax Free Exchange. Buyer agrees to allow Seller to convey the Water Right and Change Application through a like kind exchange pursuant to Section 1031 of the Internal Revenue Code and agrees to reasonably cooperate with Seller in accomplishing such exchange, so long as the exchange will not injure or prejudice the interests of Buyer in any way. Seller shall be solely responsible for making the arrangements necessary for such an exchange. Buyer shall not be obligated to participate in any transaction under this Section which imposes any cost or any liability whatsoever on Buyer. The Parties acknowledge that the arrangement of a like kind exchange under this Section would be done solely for Seller's convenience and that any such arrangement shall not constitute part of the consideration paid by Buyer for the Water Right and Change Application or Option under this Agreement. Any exchange shall not delay the Closing date without Buyer's prior written consent or increase the cost of Closing to Buyer. Buyer shall not be required to acquire in its own name or in the name of an agent such property as may be acquired by Seller to effectuate such an exchange.

15. Lease of Water Right and Change Application. The Parties acknowledge that the ninety (90) day period between the exercise of the Option and the Closing Date is for the sole purpose of facilitating Seller's like kind exchange described in Section 14 (the "Exchange Period") and that Buyer may need to divert and use the water made available under the Water Right and Change Application during the Exchange Period. If requested by Buyer, Seller shall lease the water available under the Water Right and Change Application to Buyer for One Dollar ($1.00) during the Exchange Period. No interest on the Purchase Price of the Water Right and Change Application shall be charged to Buyer during the Exchange Period.

16. Remedies in the Event of Default.

16.1. Seller's Default. In the event of Seller's default hereunder for any reason, Buyer shall deliver written notice hereof to Seller. If Seller does not cure such default within ten (10) days after receiving written notice thereof, Buyer shall be entitled to pursue all rights or remedies allowed to it at law or in equity.

16.2. Buyer's Default. The Parties recognize that Seller will incur expense in connection with the transaction contemplated by this Agreement and that it is extremely difficult and impractical to ascertain the extent of the detriment to Seller caused by Buyer's breach of this Agreement and the failure of the consummation of the transaction contemplated herein or the amount of compensation Seller should receive as a result of Buyer's breach or default. In the event of Buyer's default hereunder for any reason, Seller shall deliver written notice thereof to Buyer. If Buyer does not cure within ten (10) days after receiving written notice and the sale of the Water Right and Change Application is not consummated because of Buyer's default, then the retention of the sums in the escrow account shall be Seller's sole and exclusive remedy and not a penalty, and shall be in lieu of any other monetary or other relief.

17. Brokerage. Seller shall pay and be solely responsible for the payment of any and all brokerage commissions or other compensation due to any person or entity on account of the execution or performance of this Agreement or the consummation of the transaction contemplated hereby, if any. Seller hereby indemnifies Buyer from any and all liabilities, damages, losses and expenses (including, without limitation, reasonable attorney's fees and disbursements) arising out of any and all claims made by any person or other entity with whom Seller has dealt.

18. Indemnity.

18.1. By Seller. Seller shall indemnify, and hold Buyer, its officers, employees and agents harmless from all loss, expense (including reasonable attorney's fees), damage and liability resulting from or otherwise arising out of (i) claims of whatever nature (including without limitation claims for personal injury, wrongful death or property damage) based on causes of action arising prior to the Closing Date, (ii) claims by consultants, contractors under service contracts, and utility companies, if any, all with respect to matters that occurred prior to the Closing Date, and (iii) the inaccuracy of any representation or the breach of any covenant or agreement made by Seller under this Agreement. This indemnity agreement shall survive the Closing.

18.2. By Buyer. Buyer shall indemnify and hold Seller, his partners, officers, employees and agents harmless from all loss, expense (including reasonable attorney's fees), damage and liability resulting from (i) claims of whatever nature including without limitation claims for personal injury, wrongful death or property damage) against Seller or the Water Right based on causes of action arising after the Closing Date, (ii) claims by consultants, contractors under service contracts and utility companies, if any, all with respect to matters that occurred after the Closing Date, (iii) the inaccuracy of any representation or the breach of any covenant or agreement made by Buyer under this Agreement. This indemnity agreement shall survive the Closing.

19. Notices. Any and all notices, demands, or other communications required or desired to be given hereunder by Buyer and Seller shall be in writing and shall be validly given or made to another Party if served either personally or if deposited in the United States mail, certified or registered, or postage prepaid, return receipt requested.

To Seller: Michael S. Keyte P.O. Box 274 Mona, UT 84645	To Buyer: Spring Canyon Energy, L.L.C. P. O. Box 774000, #359 Steamboat Springs, CO 80477
With a copy (which shall not constitute notice) to: ____________________ ____________________ ____________________ ____________________	With a copy (which shall not constitute notice) to: Jody L. Williams Holme Roberts & Owen, LLP 111 East Broadway, Suite 1100 Salt Lake City, UT 84111-5233

Either Party hereto may change its address for the purpose of receiving notices, demands and other communications as herein provided by a written notice given in the manner aforesaid to the other parties.

20. Further Assurances. Each of the parties hereto shall execute and deliver any and all additional papers, documents, and other assurances, and shall do any and all acts and things reasonably necessary in connection with the performance of their obligations hereunder and to carry out the intent of the parties hereto.

21. Attorney's Fees. In the event any action or negotiation is instituted by a Party to enforce any of the terms and provisions contained herein, each Party shall pay its own attorney's fees, costs and expenses.

22. Modification or Amendments. No amendment, change or modification of this Agreement shall be valid unless in writing and signed by the parties hereto.

23. Integration. This Agreement and the attachments hereto constitutes the entire understanding and agreement of the parties with respect to the purchase of the Water Right and any and all prior agreements, understandings or representations are hereby terminated and canceled in their entirety and are of no force and effect.

24. Waiver. The waiver by any Party to this Agreement of a breach of any provision of this Agreement shall not be deemed a continuing waiver or waiver of any subsequent breach whether of the same or another provision of this Agreement.

25. Applicable Law. This Agreement shall be governed by the laws of the State of Utah.

26. Survival. The covenants, warranties, representations and indemnities contained herein shall survive the Closing.

27. Construction. All terms and words used in this Agreement, regardless of the number and gender in which they are used, shall be deemed and construed to include any other number, singular or plural; any gender, either masculine or feminine; and any corporation, partnership or other business entity and any persons acting in a representative capacity, as the context or sense of this Agreement or any section or clause herein may require.

28. Captions and Section Numbers. The captions and section numbers appearing in this Agreement are inserted only as a matter of convenience and in no way shall be construed as defining or limiting the scope or intent of the provisions of this Agreement nor as affecting the interpretation of the provisions hereof.

29. Condemnation. In the event that condemnation by a qualifying entity of all or a portion of the Water Right and Change Application shall be instituted or threatened prior to Closing, Buyer shall have the right to terminate this Agreement, and upon such termination Escrow Agent shall return all Deposits and interest thereon held in the escrow account and neither Seller nor Buyer shall have any rights or obligations hereunder. In the alternative, Buyer, at its sole discretion, shall have the right to purchase the portion of the Water Right not subject to condemnation, in which event the Purchase Price shall be reduced in proportion to that part of the Water Right acquired.

30. Binding Effect. This Agreement shall be binding upon and inure to the benefit of the Parties hereto, and to their respective heirs, personal representatives, administrators, executors, successors and assigns.

31. Assignment. Buyer shall have the right to assign this Agreement and all of Buyer's right, title and interest in this Agreement without restriction, but notice of any such assignment shall be given in writing to Seller.

32. Counterpart Execution. This Agreement may be executed as one instrument signed by both Parties or in separate counterparts hereof, each of which counterparts shall be considered an original and all of which shall be deemed to be one instrument, and any signed counterpart shall be deemed signed and delivered by the Party signing it if sent to any other Party hereto by electronic facsimile transmission.

33. May 30, 2002 Option Superseded. That Water Right Option and Purchase Agreement executed by Buyer and Seller for purchase of the Water Right dated May 30, 2002, is hereby superseded in totality by this Agreement, and hereafter it shall be void and of no further effect. Upon satisfaction of the conditions precedent set forth in Sections 7.1 through 7.6 of this Agreement, the check in the amount of Six Thousand Five Hundred Twenty-Eight and Eighty Hundredths Dollars ($6,528.80) dated July 30, 2002 and deposited to Juab Title and Abstract shall be deemed to be the Initial Option Fee described in this Agreement.

IN WITNESS WHEREOF, the parties have executed this Agreement as of the day and year first written above.

MICHAEL S. KEYTE

Michael S. Keyte

STATE OF Utah)
:ss.
COUNTY OF Salt Lake)

On this 14th day of August 2002, before me, the undersigned, a notary public in and for said state, personally appeared Michael S. Keyte, known to me to be the person whose name is subscribed to the within instrument, who duly acknowledged to me that he executed the same.

WITNESS my hand and official seal.

Trudi L. Rouse
Notary Public

Notary Public
TRUDI L. ROUSE
111 East Broadway, Suite 1100
Salt Lake City, Utah 84111
My Commission Expires
March 20, 2006
State of Utah

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SPRING CANYON ENERGY, L.L.C.

By: [signature]

Its: Principal - Manager

STATE OF Colorado)
: ss.
COUNTY OF Routt)

On the 20 day of August, 2002, personally appeared before me LOIS BANASIEWICZ, who, being by me duly sworn, did say, that (s)he is the manager of SPRING CANYON ENERGY, L.L.C., a Utah limited liability Company and that the above Water Right Option And Purchase Agreement was signed by (him)(her) in behalf of said limited liability company.

NOTARY DONNA ARELLANO STATE OF COLORADO

[signature]
Notary Public

My commission expires 9/23/2004

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EXHIBIT "A"

After Recording Return to:
Jody L. Williams
Holme Roberts & Owen, LLP
111 East Broadway, Suite 1100
Salt Lake City, Utah 84111-5233

WATER RIGHT DEED

MICHAEL S. KEYTE, an individual, with an address of P.O. Box 274, Mona, Utah 84645, Grantor, hereby conveys and warrants against all persons claiming by, through or under him, but not otherwise, to SPRING CANYON ENERGY, L.L.C., a Utah limited liability company, with an address of P.O. Box 774000, #359, Steamboat Springs, Colorado 80477, Grantee, for the sum of Ten and No/100 Dollars, the following described water right used and diverted in Juab County, State of Utah:

> Water Right No. 15-1431 for the irrigation of 40 acres and stock watering of 115 cattle or equivalent; and approved Change Application No. a21754 for the irrigation of 40 acres, the stock watering of 83 cattle or equivalent and the domestic use of 2 families; and Change Application No. ________.

WITNESS the hand of said Grantor this ______ day of ____________________, 2002.

Michael S. Keyte, Grantor

By: ______________________________
Michael S. Keyte

STATE OF UTAH)
)ss.
COUNTY OF)

On this ____day of ____________________, 2002, personally appeared before me Michael S. Keyte, the signer of the within instrument, who duly acknowledged to me that he/she executed the same.

____
Notary Public

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EXHIBIT "B"

After Recording Return to:
Jody L. Williams
Holme Roberts & Owen, LLP
111 East Broadway, Suite 1100
Salt Lake City, Utah 84111-5233

MEMORANDUM OF WATER RIGHT OPTION

THIS MEMORANDUM OF WATER RIGHT OPTION ("Memorandum") dated ______________, 2002 is by and between MICHAEL S. KEYTE an individual with an address of P.O. Box 274, Mona, Utah 84645 and SPRING CANYON ENERGY, L.L.C., a Utah limited liability company with an address of P.O. Box 774000, #359, Steamboat Springs, Colorado 80477 ("Buyer")

Recitals

A. Seller owns Water Right No. 53-1431 and approved Change Application No. a21754 (the "Water Right") in Juab County, State of Utah which is more particularly described as a water right with a maximum diversion of 163.22 acre-feet of water for the sole supply irrigation of 40 acres and stock watering of 115 cattle or equivalent under the water right and sole supply irrigation of 40 acres, stock watering of 83 cattle or equivalent, and domestic use of 2 families under the approved change application.

B. Seller and Buyer have entered into a Water Right Option and Purchase Agreement (the "Agreement"), dated __________________, 2002 (the "Effective Date"), pursuant to which Seller has granted an option to Buyer to purchase all of the Water Right.

C. Seller and Buyer are entering into this Memorandum to confirm and provide record notice of Buyer's rights under the Agreement.

Memorandum

In exchange for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Seller and Buyer agree and acknowledge as follows:

1. Grant of Option.

(a) Subject to the terms and conditions of this Memorandum and the Agreement, Seller has granted and hereby grants to Buyer, and Buyer has accepted and hereby accepts from Seller, an option (the "Option") to purchase the Water Right.

(b) The Agreement provides that unless the Option terminates earlier pursuant to the Agreement, the Option will be exercisable for a 6-month period (the "Option Period") which begins on the Effective Date and ends at midnight on the last day of the Option Period. The Agreement permits Buyer, subject to the terms and conditions thereof, to extend the Option Period for additional 6-month periods commencing on the termination date of the Option Period and ending at midnight on the last day of the extended period. The closing date for the purchase of the Water Right is ninety (90) days from the date that the Buyer exercises the Option. The Option may be extended to a maximum of 36 months from the Effective Date.

2. Access to Subject Property. Pursuant to the Agreement, Seller is required to provide Buyer and Buyer's contractors reasonable access at any time and from time to time during the Option Period and Extended Option to enter upon any property of Seller to which the Water Right is appurtenant in order to complete its due diligence or to perform other work connected to the Water Right or the filing of a permanent change application.

3. Conveyance Prohibitions. The Agreement prohibits Seller from transferring, conveying or assigning to any person or entity other than to Buyer pursuant to the Agreement, any right, title or interest in the Water Right, or encumbering the Water Right by any mortgage, deed of trust, or other instrument creating any lien or security interest or otherwise securing any debt or obligation, or creating or allowing to be created any exception, defect, or adverse claim against Seller's title to the Water Right other than the rights of Buyer under the Agreement.

4. Parties in Interest. This Memorandum shall be binding upon, and shall inure to the benefit of, the parties and their respective successors and assigns.

5. Rights of Parties Subject to Terms of Agreement. The rights and obligations of the parties under this Memorandum are subject to all of the terms and conditions of the Agreement. To the extent of any inconsistency between this Memorandum and the Agreement, the Agreement shall govern.

IN WITNESS WHEREOF, Buyer and Seller have executed this Memorandum to be effective as of the date first above written.

SELLER:

MICHAEL S. KEYTE

____
Michael S. Keyte

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BUYER:
SPRING CANYON ENERGY, L.L.C., a Utah limited liability company

By: ______________________________

Its: ______________________________

STATE OF UTAH)
:ss
COUNTY OF)

On the _____ day of _________________ 2002, before me personally appeared Michael S. Keyte, known to me to be the person that executed the within and foregoing instrument, who duly acknowledged to me that he executed the same.

____
NOTARY PUBLIC

STATE OF)
: ss.
COUNTY OF)

On the ______ day of _____________, 2002, personally appeared before me ___________________________, who, being by me duly sworn, did say, that (s)he is the managing member of SPRING CANYON ENERGY, L.L.C., a Utah limited liability Company and that the above Water Right Option And Purchase Agreement was signed by (him)(her) in behalf of said limited liability company.

____
Notary Public

After Recording Return to:
Jody L Williams
Holme Roberts & Owen, LLP
111 East Broadway, Suite 1100
Salt Lake City, Utah 84111-5233

MEMORANDUM OF WATER RIGHT OPTION

THIS MEMORANDUM OF WATER RIGHT OPTION ("Memorandum") dated August 14, 2002 is by and between MICHAEL S. KEYTE an individual with an address of P.O. Box 274, Mona, Utah 84645 and SPRING CANYON ENERGY, L.L.C., a Utah limited liability company with an address of P.O. Box 774000, #359, Steamboat Springs, Colorado 80477 ("Buyer")

Recitals

A. Seller owns Water Right No. 53-1431 and approved Change Application No. a21754 (the "Water Right") in Juab County, State of Utah which is more particularly described as a water right with a maximum diversion of 163 22 acre-feet of water for the sole supply irrigation of 40 acres and stock watering of 115 cattle or equivalent under the water right and sole supply irrigation of 40 acres, stock watering of 83 cattle or equivalent, and domestic use of 2 families under the approved change application.

B. Seller and Buyer have entered into a Water Right Option and Purchase Agreement (the "Agreement"), dated August 14, 2002 (the "Effective Date"), pursuant to which Seller has granted an option to Buyer to purchase all of the Water Right.

C. Seller and Buyer are entering into this Memorandum to confirm and provide record notice of Buyer's rights under the Agreement.

Memorandum

In exchange for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Seller and Buyer agree and acknowledge as follows·

1 Grant of Option

(a) Subject to the terms and conditions of this Memorandum and the Agreement, Seller has granted and hereby grants to Buyer, and Buyer has accepted and hereby accepts from Seller, an option (the "Option") to purchase the Water Right

(b) The Agreement provides that unless the Option terminates earlier pursuant to the Agreement, the Option will be exercisable for a 6-month period (the "Option Period") which begins on the Effective Date and ends at midnight on the last day of the Option Period

The Agreement permits Buyer, subject to the terms and conditions thereof, to extend the Option Period for additional 6-month periods commencing on the termination date of the Option Period and ending at midnight on the last day of the extended period. The closing date for the purchase of the Water Right is ninety (90) days from the date that the Buyer exercises the Option. The Option may be extended to a maximum of 36 months from the Effective Date.

2. Access to Subject Property Pursuant to the Agreement, Seller is required to provide Buyer and Buyer's contractors reasonable access at any time and from time to time during the Option Period and Extended Option to enter upon any property of Seller to which the Water Right is appurtenant in order to complete its due diligence or to perform other work connected to the Water Right or the filing of a permanent change application.

3. Conveyance Prohibitions. The Agreement prohibits Seller from transferring, conveying or assigning to any person or entity other than to Buyer pursuant to the Agreement, any right, title or interest in the Water Right, or encumbering the Water Right by any mortgage, deed of trust, or other instrument creating any lien or security interest or otherwise securing any debt or obligation, or creating or allowing to be created any exception, defect, or adverse claim against Seller's title to the Water Right other than the rights of Buyer under the Agreement.

4. Parties in Interest. This Memorandum shall be binding upon, and shall inure to the benefit of, the parties and their respective successors and assigns.

5. Rights of Parties Subject to Terms of Agreement. The rights and obligations of the parties under this Memorandum are subject to all of the terms and conditions of the Agreement. To the extent of any inconsistency between this Memorandum and the Agreement, the Agreement shall govern.

IN WITNESS WHEREOF, Buyer and Seller have executed this Memorandum to be effective as of the date first above written.

SELLER:

MICHAEL S. KEYTE

Michael S. Keyte

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BUYER:
SPRING CANYON ENERGY, L.L.C., a Utah limited liability company

By: [signature]

Its: Principal - Member

STATE OF UTAH)
:ss
COUNTY OF Salt Lake

On the 14th day of August 2002, before me personally appeared Michael S. Keyte, known to me to be the person that executed the within and foregoing instrument, who duly acknowledged to me that he executed the same.

Notary Public
TRUDI L. ROUSE
111 East Broadway, Suite 1100
Salt Lake City, Utah 84111
My Commission Expires
March 20, 2006
State of Utah

Trudi L Rouse
NOTARY PUBLIC

STATE OF Colorado)
: ss.
COUNTY OF Routt)

On the 20 day of August, 2002, personally appeared before me LOIS BANASIEWICZ, who, being by me duly sworn, did say, that (s)he is the managing member of SPRING CANYON ENERGY, L.L.C., a Utah limited liability Company and that the above Water Right Option And Purchase Agreement was signed by (him)(her) in behalf of said limited liability company.

[signature]
Notary Public

My commission expires 9/21/03

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WATER RIGHT OPTION AND
PURCHASE AGREEMENT

THIS WATER RIGHT OPTION AND PURCHASE AGREEMENT ("Agreement") is entered into as of the 5th day of August, 2002, by and between R. BLAKE GARRETT, whose mailing address is North Airport Road, Nephi, UT 84648 ("Seller") and SPRING CANYON ENERGY, L.L.C., a Utah limited liability company whose mailing address is P.O. Box 774000, #359, Steamboat Springs, CO 80477 ("Buyer"). The Seller and Buyer are referred to collectively in this Agreement as the "Parties."

RECITALS

A. Seller owns Water Right No. 53-97, Certificate No. 11837 (the "Water Right") and desires to sell the Water Right to Buyer. Seller represents that the Water Right has been quantified by the Utah State Engineer's Office ("State Engineer") as yielding a sole supply for the irrigation of 96 acres (384 acre feet annually).

B. Buyer desires to purchase the Water Right from Seller for industrial use at a facility (the "Facility") to be constructed according to the following terms and conditions. Seller desires to sell the Water Right to Buyer under the same terms and conditions.

AGREEMENT TERMS

In consideration of the mutual promises, covenants, and conditions of this Agreement, the Parties agree as follows:

1. Option to Purchase. Seller hereby sells, gives and grants to Buyer, and its assigns, the exclusive option to purchase (the "Option"), for the price hereinafter set forth, all of Seller's right, title, estate and interest in and to the Water Right. The Option becomes effective when this Agreement has been signed by the Parties and the Initial Option Fee provided for in Section 2 has been deposited with the escrow agent designated in Section 4 below (the "Escrow Agent").

1.1. Purchase Price. The price to be paid for the Water Right shall be Four Thousand Dollars ($4,000.00) for each acre-foot presently approved for diversion under the Water Right, for a total purchase price of One Million Five Hundred Thirty-Six Thousand Dollars ($1,536,000.00) (the "Purchase Price").

2. Consideration for Option. As consideration for the Option, Buyer shall pay to Seller Fifteen Thousand Three Hundred Sixty Dollars ($15,360.00) as the initial option fee (the "Initial Option Fee"). If Buyer elects to extend the Option beyond the initial 6-month period, Buyer shall make the additional Option payments for each extension as further described herein.

2.1. The Buyer shall within 10 days from the date this Agreement is signed by the Parties deposit the Initial Option Fee in escrow in an interest-bearing account to be held by the Escrow Agent. The Initial Option Fee, together with all accrued interest thereon, shall be released to Seller and become non-refundable to Buyer upon Buyer's written notice to Seller and Escrow Agent that all of the conditions precedent set forth in Sections 7.1 through 7.6 of this Agreement have been satisfied. The Initial Option Fee is in addition to, and shall not be credited against, the Purchase Price.

2.2. Buyer may extend the Option for up to 36 months from the date the Parties sign this Agreement by depositing an additional Option payment with the Escrow Agent in the amount of Fifteen Thousand Three Hundred Sixty Dollars ($15,360.00) (a "Deposit") for each six (6) months that Buyer elects to extend the Option, and by giving notice as set out in Section 3. The first such Deposit shall be made, if at all, within six months from the date Seller executes this Agreement. Each time Buyer elects to extend the Option period, as further provided in Section 3, Buyer shall, within six (6) months of the previous Deposit, deliver another Deposit to the Escrow Agent. Each Deposit shall be paid into the interest-bearing escrow account established by the Escrow Agent and administered by it in conformance with the terms and provisions of this Agreement. For example, if the Initial Option Fee was deposited into Escrow on August 1, 2002 and Buyer thereafter gives written notice of an election to extend this Option, Buyer must give the notice as provided in Section 3 and deliver a Deposit to the Escrow Agent on or before the first business day after February 1, 2003. If the Option is again extended, another Deposit must be delivered to the Escrow Agent on or before August 1, 2003.

2.3. If Buyer exercises its Option as hereinafter provided, the principal amount of the Deposits, together with all accrued interest thereon, shall be credited to the Purchase Price.

3. Period of Option and Extension. The initial period of duration of this Option is six (6) months from the date the Parties sign this Agreement (the "Option Period"). At any time during the Option Period, Buyer has the right to exercise its Option to purchase the Water Right or, at its sole discretion, terminate the Option. The Option Period may be extended in accordance with the following:

3.1. At the end of the initial Option Period, Buyer may elect to extend the Option for additional six (6) month periods upon written notice to Seller and payment of a Deposit in the same amount and frequency as described in Section 2.2 hereof for each additional six-month period.

3.2. If Buyer elects to extend the Option, it shall provide Seller with written notice of its intention no later than ten (10) days prior to the expiration of the Option period together with payment of the required Deposit to the Escrow Agent as set forth in Section 2.2. Buyer shall pay an additional Deposit for each six (6) month period that Buyer elects to extend the Option.

3.3. Buyer may extend the Option to a maximum of thirty-six (36) months. The Option shall expire upon failure of Buyer to extend the Option strictly on the terms set out in this Agreement, upon expiration of 36 months from the date the Parties sign this Agreement, or upon exercise of the Option by Buyer, whichever occurs first.

4. Escrow Agent and Opening of Escrow. The parties hereby designate First American Title Insurance Agency, Inc. of 90 South Main, Fillmore, Utah 84631[1] as the Escrow Agent and closing agent for all purposes under this Agreement. Buyer shall, within 10 days from the date this Agreement is signed by the Parties deposit the Initial Option Fee with the Escrow Agent and deliver an executed copy of this Agreement to the Escrow Agent.

5. Alienation of Interests; Encumbrances; Leases As further consideration for the sum paid for this Option, Seller shall not sell, convey, or otherwise encumber the Water Right, in any way, during the Option Period and if applicable, any additional extension(s). Seller further agrees that he will not lease the Water Right or any part thereof during either the Option Period or any extension of the Option Period without first securing the written approval of the Buyer.

5.1. Notice of Default; Trustee's Sale; Repossession; Foreclosure; Civil Litigation. In the event of any notice of default, trustee's sale, repossession, foreclosure, civil litigation or other action to enforce a lien or encumbrance against the Water Right, Buyer may take any reasonable steps necessary to prevent or forestall such action if such action would impair Buyer's rights under this Agreement. Such action by Buyer may include, but shall not be limited to, directing that any portion of the Initial Option Fee or any Deposit(s) paid into escrow may be paid to any lienholder or creditor initiating action against Seller or the Water Right. Any amounts paid by Buyer on behalf of Seller under this Section may be offset against the Purchase Price, at Buyer's election.

6. Right of Entry. During the Option Period or any applicable extension, Seller shall permit Buyer, its employees and agents, to enter upon the property of Seller to complete its due diligence or to perform other work connected to the Water Right or the filing of a permanent change application.

7. Conditions Precedent. Sections 7.1 through 7.6 shall be express conditions precedent to the release of the Initial Option Fee, except that completion of Buyer's obligations under Section 7.3 shall not be a condition precedent to release of the Initial Option Fee.

7.1. The Initial Option Fee shall be placed into escrow with the Escrow Agent for up to a sixty (60) day due diligence period during which Buyer will investigate and confirm the nature of the Water Right (the "Due Diligence Period"). To assist Buyer in the Due Diligence Period, Seller shall, within two weeks of the execution of this Agreement, deliver at his expense, a preliminary title report, together with legible copies of all documents referred to therein, including, but not limited to, the deed of condemnation concerning the Water Right and the real property that is shown as the place of use of the Water Right in the records of the State of Utah, Division of Water Rights. If, prior to the end of the Due Diligence Period, Buyer objects to the nature, sufficiency, or title to the Water Right, Seller shall have up to sixty (60) days after written notice to cure said deficiency During such cure period, the Initial Option Fee shall continue to

[1] Items should be sent to the attention of Rob Sherman Telephone number 435 743 6213 or 800 300 8344 Deposit information Wells Fargo Bank Account No 061 0026825, ABA No 121 000 248, e-mail - rsherman@firstam com

be held in escrow. If deficiencies are not cured by the end of the cure period or such additional time as may be approved by Buyer, the Initial Option Fee shall be returned to Buyer and this Agreement shall terminate.

7 2. Seller shall file with the State Engineer a permanent change application as provided for under Utah Code Annotated § 73-3-3 seeking authorization for the Water Right to be diverted from Buyer's proposed underground water well(s) and used at Buyer's Facility to be constructed in the NE¼ of the SE¼ of Section 23, Township 11 South, Range 1 West, SLBM or such other location specified by Buyer (the "Change Application"). In this regard, the Parties are obligated as follows:

(a) As soon as possible following the execution of this Agreement, but in no case later than August 15, 2002, or such later date as may be approved by Buyer, Seller shall prepare and file the Change Application with the State Engineer to facilitate Buyer's intended use of the Water Right by Buyer. The Change Application shall show Buyer as the co-applicant and shall be filed at the sole expense of Buyer. It is anticipated that the approved Change Application will be conveyed by the same deed conveying the Water Right at closing.

(b) Seller shall throughout processing of the Change Application give good faith cooperation and assistance to Buyer regarding the Change Application. Such good faith assistance and cooperation shall be a continuing obligation under this Agreement, but shall not be a condition precedent to release of the Initial Option Fee.

7.3. Documents evidencing Seller's and Buyer's authority, including powers of attorney, if needed, and such other evidence, as required, of Seller's and Buyer's authority to consummate the transaction contemplated herein.

7.4. Delivery by Seller to the Escrow Agent of a duly executed and acknowledged Water Right Deed, in the form attached hereto as Exhibit "A," conveying title to the Water Right and Change Application to Buyer and any and all other documentation reasonably required by Buyer's counsel to consummate this transaction. Such delivery shall be a conditional delivery conditioned upon Buyer's exercise of the Option and completion of closing as set out in this Agreement.

7.5. Execution and delivery to the Escrow Agent by the Parties of a Memorandum of Water Right Option in substantially the form attached hereto as Exhibit "B" and recordation of said Memorandum in the office of the Juab County Recorder of Juab County, Utah.

7.6. Delivery to the Escrow Agent of any approvals of this Agreement required by the holder of any lien or encumbrance against the Water Right.

7.7. If the conditions precedent set forth in Sections 7.1 through 7 6 have been reasonably satisfied, Buyer shall notify Seller and the Escrow Agent of such in writing and the Initial Option Fee shall become non-refundable to Buyer at that time. The non-refundable Initial Option Fee shall then be released to Seller.

8. Water Rights Approvals. Buyer's use of the Water Right requires that the State Engineer approve the Change Application provided in Section 7.2. Buyer's use also requires that at least fifty percent (50%), or 192 acre feet of the 384 acre feet of water presently approved for diversion annually under the Water Right, be approved as depletion under the approved Change Application described in 7.2 hereof. In that regard:

8.1. Seller shall diligently prosecute the Change Application to a final non-appealable approval by either the State Engineer or by the courts on appeal of any decision of the State Engineer. If the State Engineer issues a decision that rejects the Change Application, or approves the Change Application but limits depletion to less than 192 acre feet per year, the Buyer may elect to either terminate this Option or to seek judicial review of the State Engineer's decision. The Buyer may also elect to terminate this Agreement if the State Engineer issues a favorable decision (a decision approving the Change Application and designating at least 192 acre feet of depletion), but a third party appeals the favorable decision and the appeal is not resolved within 60 days. If a judicial review action is filed by a third party and Buyer does not terminate this Agreement, or if Buyer elects to seek judicial review of a decision from the State Engineer, Buyer shall bear the expense of the judicial review action.

8.2. If the State Engineer approves less than 192 acre feet as depletion under said approved Change Application, or if a third party appeals a favorable decision of the State Engineer, Buyer may unilaterally withdraw from this Agreement upon written notice and any Deposits and all interest thereon placed in escrow pursuant to Section 2, (which by definition do not include the Initial Option Fee), shall be immediately refunded to Buyer. Seller shall be entitled to retain the Initial Option Fee if Buyer withdraws under this Section 8.2.

8.3. If Buyer fails to exercise its Option hereunder, Seller may withdraw the Change Application at any time after termination of the Option.

9. Exercise of Option. The Buyer and Seller each shall use their best efforts in accomplishing the conditions precedent in Section 7 and the approval of the Change Application as described in Section 8. If Buyer elects to exercise the Option, the Option shall be exercised by Buyer giving written notice to Seller.

10. Closing of Purchase. If Buyer exercises the Option, the closing of such purchase ("Closing") shall be completed in accordance with this Section. The Parties may also provide additional written instructions if the instructions are consistent with this Agreement. The Parties instruct and authorize the Escrow Agent to close the purchase transaction as directed in this Section and any consistent written instructions provided by the Parties.

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10.1. Closing Date. The transaction contemplated herein shall close ~~one (1) year~~ from the date that Buyer exercises this Option as set forth in Section 9 above, at the Escrow Agent's office, or at such other time and place as may be mutually agreed upon by the Parties. In no event, however, shall Buyer be obligated to close the transaction unless the conditions precedent as set forth in Sections 7.1 through 7.6 herein shall have first been satisfied, and the Change Application approved as provided in Section 8, or if Buyer elects at its sole discretion, for any reason whatsoever, to not exercise the Option and thereby decides to terminate the Agreement.

The Closing Date and Closing are terms used herein to mean the date the Purchase Price is paid into escrow and the Water Right Deed and other instruments of conveyance of the Water Right, if necessary, are filed for recordation in the office of the Juab County Recorder, Juab County, Utah.

10.2. Buyer's Closing Deliveries. At the Closing, Buyer shall deliver to Seller the following:

10.2.1. Payment of the balance of the Purchase Price in cash or by certified or cashier's check payable to Seller or Seller's designee, plus Buyer's share of the Closing costs.

10.2.2. The documents evidencing the authority of Buyer to consummate the transaction contemplated herein that were deposited with the Escrow Agent as provided for in Section 7.3.

10.2.3. Any and all other documentation reasonably required by Seller's legal counsel to consummate this transaction.

10.3. Seller's Closing Deliveries. At the Closing, Seller shall deliver to Buyer the following:

10.3.1. The duly executed and acknowledged Water Right Deed deposited with the Escrow Agent prior to disbursement of the Initial Option Fee as provided for in Section 7.4 herein. Such execution and delivery prior to the disbursement of the Initial Option Fee shall be deemed complete delivery by Seller to the Escrow Agent, subject to the provisions of this Section 10, for the purposes of Closing the sale of the Water Right and Change Application. Such execution and delivery shall be deemed irrevocable except upon termination of this Agreement in accordance with the terms hereof. Seller shall nevertheless, if requested by Buyer, execute and deliver at the time of the Closing a good and sufficient Water Right Deed in the form attached hereto as Exhibit "A," conveying title to the Water Right and approved Change Application to Buyer showing any changes as necessary at the time of Closing.

10.3.2. The documents evidencing the authority of Seller to consummate the transaction contemplated herein that were deposited with the Escrow Agent as provided for in Section 7.3.

10.3.3. Any and all other documentation reasonably required by Buyer's and Seller's counsel to consummate this transaction.

10.4. Costs and Expenses. Seller and Buyer shall pay and be responsible for the following costs and expenses:

10.4.1. Seller's Costs. Seller shall pay the costs incurred by him for legal, accounting and other consultants' services together with all other costs incurred by Seller in the satisfaction of Seller's obligations under this Agreement, plus one-half of the Escrow Agent's fees and expenses incurred by the Parties in completing the Closing.

10.4.2. Buyer's Costs. Buyer shall pay the costs incurred by it for legal, accounting and other consultants' services, together with all other costs incurred by it in the satisfaction of its obligations under this Agreement, plus one-half of the Escrow Agent's fees and expenses incurred by the Parties in completing the Closing. Buyer shall pay all recordation fees for recording the Memorandum of Water Right Option provided for in Section 7.5 and the Water Right Deed upon Closing.

10.5. Possession. Seller shall cause such reconveyances of trust deed, mortgage releases, cancellation of financing statements, and any other instruments as necessary to represent release of any liens or encumbrances against the Water Right and approved Change Application to be removed prior to Closing, and Buyer shall be entitled to actual and exclusive right and possession of the Water Right and approved Change Application, free of any person or other entity having or claiming any possessory right, title or interest with respect thereto, as of the Closing.

10.6. The Escrow Agent shall record all documents necessary to release liens and encumbrances against the Water Right and approved Change Application; and record the Water Right Deed from Seller to Buyer at the time of Closing.

10.7. The Escrow Agent shall disperse the Purchase Price proceeds first to pay Seller's share of Closing costs, tax prorations and other such Closing Costs; second to retire any liens or encumbrances against the Water Right and Change Application; and third, to Seller or to such persons as Seller designates.

11. Seller's Representations and Warranties. Seller hereby makes the following representations and warranties, (it being understood and agreed by the Parties that all references herein to representations and warranties pertaining to the Water Right itself, and including the Change Application shall be applicable as of the Closing Date) and agrees that such representations and warranties shall survive the Closing:

11. Marketable Title. Seller shall have, as of the date of Closing, good and marketable title to the Water Right, subject to no liens, taxes, encumbrances, restrictions or adverse easements or interests of any kind or nature whatsoever.

11 2. No Forfeiture or Abandonment. The Water Right is in good standing in the State Engineer's office; the use of the Water Right has been consistent with the Water Right as on record in the State Engineer's office; the Water Right has been used beneficially within the last five (5) years; and neither the Water Right nor any part thereof is subject to forfeiture or abandonment for non use.

11.3. Authority. Seller and the person executing this Agreement on behalf of Seller have the full right, power and authority to enter into this Agreement and to consummate the transactions contemplated herein.

11 4. Defaults. Seller is not in default in respect of any judgment, order, writ, injunction, decision, law, ordinance or regulation of any court or governmental authority or under any lease,

mortgage, or other agreement to which it, or the Water Right, Change Application, or any portion thereof, is or might be subject which might prohibit, delay, or interfere with the consummation of the transaction contemplated hereby or affect the right, title, and interest or the condition of the Water Right and Change Application; and the execution and delivery of this Agreement. Further, the performance by Seller of its obligations hereunder will not (i) result in the breach or termination of or violate or constitute a default under any such lease, mortgage, or other agreement, or (ii) result in the creation or imposition of any lien, charge, or encumbrance upon the Water Right or Change Application or any portion thereof, or (iii) violate any law, regulation, judgment, or order of any governmental entity.

11.5. Documents. All documents delivered to Buyer pursuant hereto are, to the best of Seller's knowledge, true, correct, and complete copies of the original documents. The Water Right and Change Application will not at Closing be subject to any unrecorded instruments affecting the title to or the right to the use of the Water Right for the Buyer's purposes as set forth herein.

11.6. Maintenance Pending Closing. From and after the date of execution hereof and until Closing, Seller shall maintain and manage the Water Right so as to do nothing which might damage the value or condition of the Water Right and Change Application. Seller shall protect the Water Right from forfeiture or abandonment. Seller will not knowingly engage in any conduct that will adversely affect the likelihood of a favorable decision on the Change Application. If necessary to prevent forfeiture or abandonment of the Water Right, at Buyer's sole discretion, Seller will, upon Buyer's request, file an Application for Nonuse of Water on any unused portion of the Water Right.

11.7. Litigation and Claims. Seller has not received any notice of or is otherwise not aware of any claims, actions, suits or other proceedings, whether pending, threatened, or to the best of his knowledge, contemplated by any governmental department or agency or any corporation, partnership or other entity or person whatsoever, or to the best of his knowledge, after due inquiry, any facts which could constitute the basis for any claim or litigation which might prohibit, delay or interfere with the consummation of the transaction contemplated hereby or which, if adversely determined, might affect the right, title and interest which may be acquired by the Buyer in and to the Water Right and Change Application, or the condition or the value of the Water Right and Change Application.

11.8. Available Data. At all reasonable times hereafter, up to and including the Closing, Seller and his accountants, engineers, and agents shall make available to Buyer, its counsel and/or accountants or other consultants, for examination at reasonable times, all reports, studies and all other relevant documents reasonably pertaining to the Water Right and Change Application.

11 9. Water Right. The Water Right has been accurately and completely described in this Agreement. All necessary approvals for use of the Water Right for Seller's present uses have been obtained by or on behalf of Seller and are in full force and effect. The Water Right is titled in Seller's name at the Utah Division of Water Rights.

12. Buyer's Representations and Warranties. In order to induce Seller to execute this Agreement, and to enter in the transaction contemplated hereby, Buyer hereby represents and warrants that:

12.1. Full Power and Authority. Buyer is a limited liability company organized and existing under the laws of the State of Utah and possesses the capability, power, and legal authority to perform all acts and obligations required of it hereunder.

12.2. No Conflict. The execution, delivery, and performance of this Agreement by the Buyer and the consummation of the transactions contemplated herein will not (i) result in a breach or acceleration of or constitute a default or event of termination under the provisions of any agreement or instrument to which Buyer is a party or bound; or (ii) constitute or result in the violation or breach by Buyer of any judgment, order, writ, injunction, or decree issued against or imposed upon Buyer or result in the violation of any applicable law, ordinance, rule or regulation of any governmental authority.

13. Risk of Loss. Risk of loss to the Water Right shall be Seller's until Closing and transfer of title as herein provided, except any loss or reduction, subject to the provisions of Section 8.2 hereof, that occurs as a result of any decision on the Change Application.

14. 1031 Tax Free Exchange. Buyer agrees to allow Seller to convey the Water Right and Change Application through a like kind exchange pursuant to Section 1031 of the Internal Revenue Code and agrees to reasonably cooperate with Seller in accomplishing such exchange, so long as the exchange will not injure or prejudice the interests of Buyer in any way. Seller shall be solely responsible for making the arrangements necessary for such an exchange. Buyer shall not be obligated to participate in any transaction under this Section which imposes any cost or any liability whatsoever on Buyer. The Parties acknowledge that the arrangement of a like kind exchange under this Section would be done solely for Seller's convenience and that any such arrangement shall not constitute part of the consideration paid by Buyer for the Water Right and Change Application or Option under this Agreement. Any exchange shall not delay the Closing date without Buyer's prior written consent or increase the cost of Closing to Buyer. Buyer shall not be required to acquire in its own name or in the name of an agent such property as may be acquired by Seller to effectuate such an exchange.

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90 days 15. Lease of Water Right and Change Application. The Parties acknowledge that the ~~one year~~ period between the exercise of the Option and the Closing Date is for the sole purpose of facilitating Seller's like kind exchange described in Section 14 (the "Exchange Period") and that Buyer may need to divert and use the water made available under the Water Right and Change Application during the Exchange Period. If requested by Buyer, Seller shall lease the water available under the Water Right and Change Application to Buyer for One Dollar ($1.00) during the Exchange Period. No interest on the Purchase Price of the Water Right and Change Application shall be charged to Buyer during the Exchange Period.

16. Remedies in the Event of Default.

16.1. Seller's Default. In the event of Seller's default hereunder for any reason, Buyer shall deliver written notice hereof to Seller. If Seller does not cure such default within ten (10) days after receiving written notice thereof, Buyer shall be entitled to pursue all rights or remedies allowed to it at law or in equity.

16.2. Buyer's Default. The Parties recognize that Seller will incur expense in connection with the transaction contemplated by this Agreement and that it is extremely difficult and impractical to ascertain the extent of the detriment to Seller caused by Buyer's breach of this Agreement and the failure of the consummation of the transaction contemplated herein or the amount of compensation Seller should receive as a result of Buyer's breach or default. In the event of Buyer's default hereunder for any reason, Seller shall deliver written notice thereof to Buyer. If Buyer does not cure within ten (10) days after receiving written notice and the sale of the Water Right and Change Application is not consummated because of Buyer's default, then the retention of the sums in the escrow account shall be Seller's sole and exclusive remedy and not a penalty, and shall be in lieu of any other monetary or other relief.

17. Brokerage. Seller shall pay and be solely responsible for the payment of any and all brokerage commissions or other compensation due to any person or entity on account of the execution or performance of this Agreement or the consummation of the transaction contemplated hereby, if any. Seller hereby indemnifies Buyer from any and all liabilities, damages, losses and expenses (including, without limitation, reasonable attorney's fees and disbursements) arising out of any and all claims made by any person or other entity with whom Seller has dealt.

18. Indemnity.

18.1. By Seller. Seller shall indemnify, and hold Buyer, its officers, employees and agents harmless from all loss, expense (including reasonable attorney's fees), damage and liability resulting from or otherwise arising out of (i) claims of whatever nature (including without limitation claims for personal injury, wrongful death or property damage) based on causes of action arising prior to the Closing Date, (ii) claims by consultants, contractors under service contracts, and utility companies, if any, all with respect to matters that occurred prior to the Closing Date, and (iii) the inaccuracy of any representation or the breach of any covenant or agreement made by Seller under this Agreement. This indemnity agreement shall survive the Closing.

18.2. By Buyer. Buyer shall indemnify and hold Seller, his partners, officers, employees and agents harmless from all loss, expense (including reasonable attorney's fees), damage and liability resulting from (i) claims of whatever nature including without limitation claims for personal injury, wrongful death or property damage) against Seller or the Water Right based on causes of action arising after the Closing Date, (ii) claims by consultants, contractors under service contracts and utility companies, if any, all with respect to matters that occurred after the Closing Date, (iii) the inaccuracy of any representation or the breach of any covenant or agreement made by Buyer under this Agreement. This indemnity agreement shall survive the Closing.

19. Notices. Any and all notices, demands, or other communications required or desired to be given hereunder by Buyer and Seller shall be in writing and shall be validly given or made to another Party if served either personally or if deposited in the United States mail, certified or registered, or postage prepaid, return receipt requested.

To Seller: R. Blake Garrett North Airport Road Nephi, UT 84648	To Buyer: Spring Canyon Energy, L.L.C. P. O. Box 774000, #359 Steamboat Springs, CO 80477
With a copy (which shall not constitute notice) to: Warren H. Peterson Waddingham & Peterson 362 West Main Delta, UT 84624-9205	With a copy (which shall not constitute notice) to: Jody L. Williams Holme Roberts & Owen, LLP 111 East Broadway, Suite 1100 Salt Lake City, UT 84111-5233

Either Party hereto may change its address for the purpose of receiving notices, demands and other communications as herein provided by a written notice given in the manner aforesaid to the other parties.

20. Further Assurances. Each of the parties hereto shall execute and deliver any and all additional papers, documents, and other assurances, and shall do any and all acts and things reasonably necessary in connection with the performance of their obligations hereunder and to carry out the intent of the parties hereto.

21. Attorney's Fees. In the event any action or negotiation is instituted by a Party to enforce any of the terms and provisions contained herein, each Party shall pay its own attorney's fees, costs and expenses.

22. Modification or Amendments. No amendment, change or modification of this Agreement shall be valid unless in writing and signed by the parties hereto.

23. Integration. This Agreement and the attachments hereto constitutes the entire understanding and agreement of the parties with respect to the purchase of the Water Right and any and all prior agreements, understandings or representations are hereby terminated and canceled in their entirety and are of no force and effect.

24. Waiver. The waiver by any Party to this Agreement of a breach of any provision of this Agreement shall not be deemed a continuing waiver or waiver of any subsequent breach whether of the same or another provision of this Agreement.

25. Applicable Law. This Agreement shall be governed by the laws of the State of Utah.

26. Survival. The covenants, warranties, representations and indemnities contained herein shall survive the Closing.

27. Construction. All terms and words used in this Agreement, regardless of the number and gender in which they are used, shall be deemed and construed to include any other number, singular or plural; any gender, either masculine or feminine; and any corporation, partnership or other business entity and any persons acting in a representative capacity, as the context or sense of this Agreement or any section or clause herein may require.

28. Captions and Section Numbers. The captions and section numbers appearing in this Agreement are inserted only as a matter of convenience and in no way shall be construed as defining or limiting the scope or intent of the provisions of this Agreement nor as affecting the interpretation of the provisions hereof.

29. Condemnation. In the event that condemnation by a qualifying entity of all or a portion of the Water Right and Change Application shall be instituted or threatened prior to Closing, Buyer shall have the right to terminate this Agreement, and upon such termination Escrow Agent shall return all Deposits and interest thereon held in the escrow account and neither Seller nor Buyer shall have any rights or obligations hereunder. In the alternative, Buyer, at its sole discretion, shall have the right to purchase the portion of the Water Right not subject to condemnation, in which event the Purchase Price shall be reduced in proportion to that part of the Water Right acquired.

30. Binding Effect. This Agreement shall be binding upon and inure to the benefit of the Parties hereto, and to their respective heirs, personal representatives, administrators, executors, successors and assigns.

31. Assignment. Buyer shall have the right to assign this Agreement and all of Buyer's right, title and interest in this Agreement without restriction, but notice of any such assignment shall be given in writing to Seller.

32. Counterpart Execution. This Agreement may be executed as one instrument signed by both Parties or in separate counterparts hereof, each of which counterparts shall be considered an original and all of which shall be deemed to be one instrument, and any signed counterpart shall be deemed signed and delivered by the Party signing it if sent to any other Party hereto by electronic facsimile transmission.

IN WITNESS WHEREOF, the parties have executed this Agreement as of the day and year first written above.

R. BLAKE GARRETT

R. Blake Garrett

STATE OF Utah)
:ss.
COUNTY OF Juab)

On this 26th day of July 2002, before me, the undersigned, a notary public in and for said state, personally appeared R. Blake Garrett, known to me to be the person whose name is subscribed to the within instrument, who duly acknowledged to me that he executed the same.

WITNESS my hand and official seal.

L R Wickel
Notary Public

NOTARY PUBLIC
LON R. WICKEL
3 NORTH MAIN
NEPHI, UT 84648
COMMISSION EXPIRES
NOV. 10, 2003
STATE OF UTAH

SPRING CANYON ENERGY, L.L.C.

By: Lois Barasiewicz

Its: Principal

STATE OF Colorado)
: ss.
COUNTY OF Routt)

On the 5 day of Aug, 2002, personally appeared before me Lois Barasiewicz, who, being by me duly sworn, did say, that (s)he is the manager of SPRING CANYON ENERGY, L.L.C., a Utah limited liability Company and that the above Water Right Option And Purchase Agreement was signed by (him)(her) in behalf of said limited liability company.

Notary Public

SUSAN C. WIDNER NOTARY PUBLIC STATE OF COLORADO

My Commission Expires:
March 9, 2005

EXHIBIT "A"

After Recording Return to:
Jody L. Williams
Holme Roberts & Owen, LLP
111 East Broadway, Suite 1100
Salt Lake City, Utah 84111-5233

WATER RIGHT DEED

R. BLAKE GARRETT, an individual, with an address of North Airport Road, Nephi, Utah 84648, Grantor, hereby conveys and warrants against all persons claiming by, through or under him, but not otherwise, to SPRING CANYON ENERGY, L.L.C., a Utah limited liability company, with an address of P.O. Box 774000, #359, Steamboat Springs, Colorado 80477, Grantee, for the sum of Ten and No/100 Dollars, the following described water right used and diverted in Juab County, State of Utah:

384 acre-feet of Water Right No. 53-97, perfected for the irrigation of 96 acres (sole supply) and Change Application No. ______________.

WITNESS the hand of said Grantor this ______ day of ____________________, 2002.

R. Blake Garrett

By: ______________________________________
R. Blake Garrett

STATE OF UTAH)
)ss.
COUNTY OF)

On this ____day of ____________________, 2002, personally appeared before me R. Blake Garrett, the signer of the within instrument, who duly acknowledged to me that he/she executed the same.

____
Notary Public

#119797 v3

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EXHIBIT "B"

After Recording Return to:
Jody L. Williams
Holme Roberts & Owen, LLP
111 East Broadway, Suite 1100
Salt Lake City, Utah 84111-5233

MEMORANDUM OF WATER RIGHT OPTION

THIS MEMORANDUM OF WATER RIGHT OPTION ("Memorandum") dated ______________, 2002 is by and between BLAKE R. GARRETT an individual with an address of North Airport Road, Nephi, Utah 84645 and SPRING CANYON ENERGY, L.L.C., a Utah limited liability company with an address of P.O. Box 774000, #359, Steamboat Springs, Colorado 80477 ("Buyer")

Recitals

A. Seller owns Water Right No. 53-97 (the "Water Right") in Juab County, State of Utah which is more particularly described as a perfected water right with a maximum diversion of 384 acre-feet of water for the sole supply irrigation of 96 acres TIN#______________________.

B. Seller and Buyer have entered into a Water Right Option and Purchase Agreement (the "Agreement"), dated ______________ ____, 2002 (the "Effective Date"), pursuant to which Seller has granted an option to Buyer to purchase all of the Water Right.

C. Seller and Buyer are entering into this Memorandum to confirm and provide record notice of Buyer's rights under the Agreement.

Memorandum

In exchange for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Seller and Buyer agree and acknowledge as follows:

1. Grant of Option.

(a) Subject to the terms and conditions of this Memorandum and the Agreement, Seller has granted and hereby grants to Buyer, and Buyer has accepted and hereby accepts from Seller, an option (the "Option") to purchase the Water Right.

(b) The Agreement provides that unless the Option terminates earlier pursuant to the Agreement, the Option will be exercisable for an 18 month period (the "Option Period") which begins on the Effective Date and ends at midnight on the last day of the Option Period.

The Agreement permits Buyer, subject to the terms and conditions thereof, to extend the Option Period for an additional 18 month period (the "Extended Option Period") commencing on the termination date of the Option Period and ending at midnight on the last day of the Extended Option Period. The closing date for the purchase of the Water Right is one year from the date that the Buyer exercises the Option.

2. Access to Subject Property. Pursuant to the Agreement, Seller is required to provide Buyer and Buyer's contractors reasonable access at any time and from time to time during the Option Period and Extended Option to enter upon the property of Seller to which the Water Right is appurtenant in order to complete its due diligence or to perform other work connected to the Water Right or the filing of a permanent change application.

3. Conveyance Prohibitions. The Agreement prohibits Seller from transferring, conveying or assigning to any person or entity other than to Buyer pursuant to the Agreement, any right, title or interest in the Water Right, or encumbering the Water Right by any mortgage, deed of trust, or other instrument creating any lien or security interest or otherwise securing any debt or obligation, or creating or allowing to be created any exception, defect, or adverse claim against Seller's title to the Water Right other than the rights of Buyer under the Agreement.

4. Parties in Interest. This Memorandum shall be binding upon, and shall inure to the benefit of, the parties and their respective successors and assigns.

5. Rights of Parties Subject to Terms of Agreement. The rights and obligations of the parties under this Memorandum are subject to all of the terms and conditions of the Agreement. To the extent of any inconsistency between this Memorandum and the Agreement, the Agreement shall govern.

IN WITNESS WHEREOF, Buyer and Seller have executed this Memorandum to be effective as of the date first above written.

SELLER:

BLAKE R. GARRETT

By: ______________________________

BUYER:

SPRING CANYON ENERGY, L.L.C., a Utah limited liability company

By: ______________________________

Its ______________________________

STATE OF UTAH)
:ss
COUNTY OF)

On the _____ day of _________________ 2002, before me personally appeared Blake R. Garrett, known to me to be the person that executed the within and foregoing instrument, who duly acknowledged to me that he executed the same.

____
NOTARY PUBLIC

STATE OF)
:ss
COUNTY OF)

On the _____ day of _________________ 2002, before me personally appeared ___________________, known to me to be the person that executed the within and foregoing instrument, who duly acknowledged to me that she executed the same.

____
NOTARY PUBLIC

After Recording Return to:
Jody L. Williams
Holme Roberts & Owen, LLP
111 East Broadway, Suite 1100
Salt Lake City, Utah 84111-5233

MEMORANDUM OF WATER RIGHT OPTION

THIS MEMORANDUM OF WATER RIGHT OPTION ("Memorandum") dated August 5, 2002 is by and between R. BLAKE GARRETT an individual with an address of North Airport Road, Nephi, Utah 84648 and SPRING CANYON ENERGY, L.L.C., a Utah limited liability company with an address of P.O. Box 774000, #359, Steamboat Springs, Colorado 80477 ("Buyer")

Recitals

A. Seller owns Water Right No. 53-97 (the "Water Right") in Juab County, State of Utah which is more particularly described as a perfected water right with a maximum diversion of 384 acre-feet of water for the sole supply irrigation of 96 acres.

B. Seller and Buyer have entered into a Water Right Option and Purchase Agreement (the "Agreement"), dated 5 August, 2002 (the "Effective Date"), pursuant to which Seller has granted an option to Buyer to purchase all of the Water Right.

C. Seller and Buyer are entering into this Memorandum to confirm and provide record notice of Buyer's rights under the Agreement.

Memorandum

In exchange for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Seller and Buyer agree and acknowledge as follows:

1. Grant of Option.

(a) Subject to the terms and conditions of this Memorandum and the Agreement, Seller has granted and hereby grants to Buyer, and Buyer has accepted and hereby accepts from Seller, an option (the "Option") to purchase the Water Right.

(b) The Agreement provides that unless the Option terminates earlier pursuant to the Agreement, the Option will be exercisable for a 6-month period (the "Option Period") which begins on the Effective Date and ends at midnight on the last day of the Option Period. The Agreement permits Buyer, subject to the terms and conditions thereof, to extend the Option Period for additional 6-month periods commencing on the termination date of the Option Period and ending at midnight on the last day of the extended period. The closing date for the purchase of the Water Right is one year from the date that the Buyer exercises the Option. The Option may be extended to a maximum of 36 months from the Effective Date.

2. Access to Subject Property. Pursuant to the Agreement, Seller is required to provide Buyer and Buyer's contractors reasonable access at any time and from time to time during the Option Period and Extended Option to enter upon any property of Seller to which the Water Right is appurtenant in order to complete its due diligence or to perform other work connected to the Water Right or the filing of a permanent change application.

3. Conveyance Prohibitions. The Agreement prohibits Seller from transferring, conveying or assigning to any person or entity other than to Buyer pursuant to the Agreement, any right, title or interest in the Water Right, or encumbering the Water Right by any mortgage, deed of trust, or other instrument creating any lien or security interest or otherwise securing any debt or obligation, or creating or allowing to be created any exception, defect, or adverse claim against Seller's title to the Water Right other than the rights of Buyer under the Agreement.

4. Parties in Interest. This Memorandum shall be binding upon, and shall inure to the benefit of, the parties and their respective successors and assigns.

5. Rights of Parties Subject to Terms of Agreement. The rights and obligations of the parties under this Memorandum are subject to all of the terms and conditions of the Agreement. To the extent of any inconsistency between this Memorandum and the Agreement, the Agreement shall govern.

IN WITNESS WHEREOF, Buyer and Seller have executed this Memorandum to be effective as of the date first above written.

SELLER:

R. BLAKE GARRETT

R. Blake Garrett

R. Blake Garrett

BUYER:

SPRING CANYON ENERGY, L.L.C., a Utah limited liability company

By: Rob Dangerfield

Its: Principal, Manager.

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9951

STATE OF UTAH)
:ss
COUNTY OF Juab)

On the 26th day of July 2002, before me personally appeared R. Blake Garrett, known to me to be the person that executed the within and foregoing instrument, who duly acknowledged to me that he executed the same.

NOTARY PUBLIC

NOTARY PUBLIC
LON R. WICKEL
3 NORTH MAIN
NEPHI, UT 84648
COMMISSION EXPIRES
NOV. 10, 2003
STATE OF UTAH

STATE OF Colorado)
: ss.
COUNTY OF Routt)

On the 5 day of August, 2002, personally appeared before me Lois Banasiewicz, who, being by me duly sworn, did say, that (s)he is the managing member of SPRING CANYON ENERGY, L.L.C., a Utah limited liability Company and that the above Water Right Option And Purchase Agreement was signed by (him)(her) in behalf of said limited liability company.

Notary Public

SUSAN C. WIDNER
NOTARY
PUBLIC
STATE OF COLORADO

My Commission Expires:
March 9, 2005

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3010

USA POWER PARTNERS, LLC

ALPINE BANK
82-340/1021 339

7/29/2002

PAY TO THE ORDER OF First American Title Insurance Agency, In $ **15,360.00

Fifteen Thousand Three Hundred Sixty and 00/100*** DOLLARS

Details on Back. Security Features Included

First American Title Insurance Agency, In

MEMO Blake Garrett Water Right Option

USA POWER PARTNERS, LLC 3010

First American Title Insurance Agency, In 7/29/2002

Blake Garrett-Spring Canyon 15,360.00

Alpine Bank Blake Garrett Water Right Option 15,360.00

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UTAH DIVISION OF AIR QUALITY
NEW SOURCE PLAN REVIEW

Lois Banasiewicz
Managing Member
Spring Canyon Energy, LLC
P.O. Box 774000-359
Steamboat Springs, Colorado 80477

Project fee code: N2627-001

RE: Power Generating Facility with One Natural Gas Fired Combined Cycle Turbine Generator Set with Duct Burner
Juab County, CDS SM; ATT, NSPS, HAPs

REVIEW ENGINEER: Milka M. Radulovic
DATE: August 16, 2002
NOTICE OF INTENT SUBMITTED: August 15, 2002
PLANT CONTACT: Lois Banasiewicz
PHONE NUMBER: (970) 871-6223
FAX NUMBER (970) 871-6234
SOURCE LOCATION: From Salt Lake take I-15 south approximately 77 miles to Hwy 54. Take exit and proceed west through Mona. Go ½ mile north on Goshen Canyon Road; Plant site is ½ mile to the west.
Juab County

UTM COORDINATES: 4,410.042 km. Northing, 422.81 km. Easting, Zone 12
UTM datum NAD27

APPROVALS,
Peer Engineer JDJ 10/10/02
John Jenks

DAQ requests that a company/corporation official read the attached draft/proposed Plan Review with Recommended Approval Order Conditions. If this person does not understand or does not agree with the conditions, the PLAN REVIEW ENGINEER should be contacted within five days after receipt of the Plan Review. Special attention needs to be addressed to the Recommended AO Conditions because they will be recommended for the final AO. If this person understands and the company/corporation agrees with the Plan Review or Recommended AO Conditions, this person should sign below and return (can use FAX # 801-536-4099) within 10 days after receipt of the conditions. If the Plan Review Engineer is not contacted within 10 days, the Plan Review Engineer shall assume that the Company/Corporation official agrees with this Plan Review and will process the Plan Review towards final approval. A 30-day public comment period will be required before the Approval Order can be issued.

Thank You

Applicant Contact Lois Banasiewicz 10/11/02
(Signature & Date)

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UTAH DIVISION OF AIR QUALITY
NEW SOURCE PLAN REVIEW

Lois Banasiewicz
Managing Member
Spring Canyon Energy, LLC
P.O. Box 774000-359
Steamboat Springs, Colorado 80477

Project fee code: N2627-001

RE: Power Generating Facility with One Natural Gas Fired Combined Cycle Turbine Generator Set with Duct Burner
Juab County, CDS SM; ATT; NSPS, HAPs

REVIEW ENGINEER: Milka M. Radulovic
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PHONE NUMBER: (970) 871-6223
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Juab County

UTM COORDINATES: 4,410.042 km. Northing, 422.81 km. Easting, Zone 12
UTM datum NAD27

APPROVALS:

Peer Engineer ______________________________
John Jenks

DAQ requests that a company/corporation official read the attached draft/proposed Plan Review with Recommended Approval Order Conditions. If this person does not understand or does not agree with the conditions, the PLAN REVIEW ENGINEER should be contacted within five days after receipt of the Plan Review. Special attention needs to be addressed to the Recommended AO Conditions because they will be recommended for the final AO. If this person understands and the company/corporation agrees with the Plan Review or Recommended AO Conditions, this person should sign below and return (can use FAX # 801-536-4099) within 10 days after receipt of the conditions. If the Plan Review Engineer is not contacted within 10 days, the Plan Review Engineer shall assume that the Company/Corporation official agrees with this Plan Review and will process the Plan Review towards final approval. A 30-day public comment period will be required before the Approval Order can be issued.

Thank You

Applicant Contact ______________________________
(Signature & Date)

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TYPE OF IMPACT AREA

Attainment Area.. Yes
Non-attainment Area
    PM_{10} .... No
    SO_2 .... No
    CO .... No
Maintenance Area
    Ozone .... No
    CO .... No

NSPS .... Yes
    40 CFR Part 60, Subparts A, Da and GG
NESHAP .... No
MACT .... No
Hazardous Air Pollutants (HAPs) .... Yes (from natural gas combustion)
Hazardous Air Pollutants Major Source .... No
New Major Source .... No
Major Modification .... No
PSD Permit .... No
PSD Increment (modeling).. Yes
Operating Permit Program
    Minor .... Yes
    Major .... No

Send to EPA .... Yes
Comment period..30-days

Abstract

Spring Canyon Energy, LLC (SCE) is proposing to construct, own, and operate a new power generating facility in the Juab valley, Juab County, just west of the Mona Reservoir. The facility will consist of one natural gas turbine generator set in a combined cycle configuration [with one heat recovery steam generator (HRSG) and one steam turbine-generator]. In addition, there will be one diesel fired emergency generator, one diesel-fired emergency fire pump, small diesel fuel storage tanks, an air- cooled condenser (to condense spent steam back into water for recycling to the HRSG), and aqueous ammonia storage and handling equipment. The HRSG duct burners will be fired with natural gas to augment waste heat from the gas turbine exhaust. The power facility will operate with a combined net maximum generating capacity of about 280 MW at 0^0F. It is anticipated that the gas turbine will be purchased from General Electric with Dry Lo-NO_x combustion system. NO_x emissions from the gas turbine will be controlled to 2 ppmvd at 15% O_2 reference (by selective catalytic reduction system), CO to 4 ppmvd at 15% O_2 reference (9 ppmvd with duct firing), and ammonia slippage to 10 ppm. The turbine will not be designed to operate in a simple-cycle mode (i.e., bypassing the HRSG unit). Raw materials used at the Spring Canyon plant in addition to natural gas and air are water (to generate the steam) and ammonia for the selective catalytic (NO_x) reduction process. Use of the dry type air-cooled condenser greatly reduces the plant's water usage.

Juab County is an attainment area of the National Ambient Air Quality Standards (NAAQS) for all pollutants.

New Source Performance Standards (NSPS) 40 CFR 60, Subpart GG (Standards of Performance for Stationary Gas Turbines) applies to the proposed turbine. NSPS 40 CFR 60, Subpart Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978) applies to the duct burners.

Estimated annual emissions from the entire facility, in tons per year, will be no more than: 66,4 of NO_x, 97.5 of CO, 5.3 of SO_2, 70.9 of PM_{10}, 67.12 of VOCs, and 5.7 tons of hazardous air pollutants (mainly formaldehyde).

Since the emissions have increased above modeling threshold levels for the NO_x, CO, PM_{10}, and formaldehyde, an air quality modeling assessment consistent with UAC R307-410-2 was performed. The US EPA and the State accepted Industrial Source Complex Short Term - Version 3 (ISCST3) model was used by the Applicant to predict air pollutant concentrations under a simple/complex terrain/wake effect situation. The modeling analysis indicated, and the State verified, that there would be no violations of NAAQS and Prevention of Significant Deterioration increments consumption for the proposed project.

Newspaper Notice

Spring Canyon Energy, LLC (SCE) is proposing to construct, own, and operate a new power generating facility in the Juab valley, Juab County, just west of the Mona Reservoir. The facility will consist of one natural gas turbine generator set in a combined cycle configuration [with one heat recovery steam generator (HRSG) and one steam turbine-generator]. In addition, there will be one diesel fired emergency generator, one diesel-fired emergency fire pump, small diesel fuel storage tanks, an air- cooled condenser (to condense spent steam back into water for recycling to the HRSG), and aqueous ammonia storage and handling equipment. The HRSG duct burners will be fired with natural gas to augment waste heat from the gas turbine exhaust. The power facility will operate with a combined net maximum generating capacity of about 280 MW at 0^0F. It is anticipated that the gas turbine will be purchased from General Electric with Dry Lo-NO_x combustion system. NO_x emissions from the gas turbine will be controlled to 2 ppmvd at 15% O_2 reference (by selective catalytic reduction system), CO to 4 ppmvd at 15% O_2 reference (9 ppmvd with duct firing), and ammonia slippage to 10 ppm. The turbine will not be designed to operate in a simple-cycle mode (i.e., bypassing the HRSG unit). Raw materials used at the Spring Canyon plant in addition to natural gas and air are water (to generate the steam) and ammonia for the selective catalytic (NO_x) reduction process. Use of the dry type air-cooled condenser greatly reduces the plant's water usage.

It has been determined that the conditions of the Utah Administrative Code R307-401-6 and the Federal rules have been met. The Executive Secretary intends to issue an Approval Order after a 30-day public comment period is held. This comment period is being held to receive and evaluate public input on the project proposed by Spring Canyon Energy, LLC.

I. DESCRIPTION OF PROPOSAL

1.0 Introduction

Summary

In an effort to ensure a reliable supply of electrical generation to Utah, Spring Canyon Energy, LLC intends to install, own and operate a combined natural gas fueled turbine-generator set at a new power generating facility to be located near Mona in Juab County. The facility will consist of one natural gas turbine generator set in a combined cycle configuration [with one heat recovery steam generator (HRSG) and one steam turbine-generator]. In addition, there will be at the facility one diesel fired emergency generator, one diesel-fired emergency fire pump, small diesel fuel storage tanks, an air- cooled condenser (to condense spent steam back into water for recycling to the HRSG), and aqueous ammonia storage and handling equipment. The HRSG duct burners will be fired with natural gas to augment waste heat from the gas turbine exhaust. The power facility will operate with a combined net maximum generating capacity of about 280 MW at 0^0F. It is anticipated that the gas turbine will be purchased from General Electric with Dry Lo-NO_x combustion system. The turbine will not be designed to operate in a simple-cycle mode (i.e., bypassing the Heat Recovery Steam Generating Unit). Raw materials used at the Spring Canyon plant in addition to natural gas and air are water (to generate the steam) and ammonia for the selective catalytic (NO_x) reduction process. Use of the dry type air-cooled condenser greatly reduces the plant's water usage.

The gas turbine emissions (corrected to 15% O_2) will be 2.0 ppmdv NO_x, 4.0 ppmvd CO (9.0 ppmdv with duct firing) and ammonia slippage to 10 ppm. Annual potential to emit emissions from the facility will be no greater than 66.4 tons of NO_x, 97.5 tons of CO, 70.9 tons of fine particulates (PM_{10}), 67 12 tons of volatile organic compounds (VOCs), 5.3 tons of SO_2 and 5.7 tons of hazardous air pollutants (HAPs).

Background

The need for the facility is a result of a significant increase in the electrical demand. Additionally, the plant will provide a voltage support in the area. Power generation from natural gas fuel provides the lowest emission option.

It is necessary to locate the facility near Mona, Juab County, Utah, classified as an attainment area by EPA Clean Air Standards, which is close to an electrical substation to minimize cost of electrical transmission lines needed. It is also located near the existing high capacity power lines and an adequately sized high-pressure natural gas supply line. In addition, the facility needs to be located in rural, not heavily populated area; an area where water and or water rights need to be obtainable; sufficient contiguous acreage needs to be available at reasonably affordable price; and correct zoning will be in place or acceptable to local community Planning Department or equivalent.

A. Spring Canyon Energy, LLC (SCE) is proposing to construct a natural gas-fired, combined-cycle power generating facility near Mona, Juab County, Utah.

The Spring Canyon facility will consist of one natural gas fueled turbine generator set in a combined cycle configuration with one steam turbine generator set. Natural gas (no other fuel will be used) will be introduced with ambient air (chilled when ambient temperatures are above 59^{0}F) into a General Electric Frame 7FA (PG7241FA) gas turbine to produce approximately a maximum of 158 MW gross output at 0°F ambient conditions.

The gas turbine is a heavy-duty industrial type frame unit representing state of the art current day technology. Gas turbine inlet air is compressed and fuel is then introduced and ignited to produce hot exhaust gases that are then expanded through the turbine section of the machine. The rotating turbine in turn drives the generator that produces electricity, the only product delivered by the facility. Waste exhaust heat from the gas turbine is directed into a heat recovery steam generator where it is augmented by natural gas fired duct burners located within the HRSG to produce steam. This steam is used internally at the plant to drive a steam turbine generator to create up to about 122 MW of additional "combined cycle" power for export. An air- cooled condenser will condense spent steam from the steam turbine exhaust back into water for recycling to the HRSG. Use of the dry type air-cooled condenser greatly reduces the plant's water usage.

It is anticipated that the gas turbine will be purchased from General Electric. The unit would be manufactured in Greenville, South Carolina, and would be configured with the latest technology Dry Lo-NOx combustion system, which when combined with the SCR catalyst system in the HRSG, qualifies as BACT Emission Rate for NO_x for this type of combined cycle power plant. NO_x emissions in the turbine exhaust gas will be controlled to 9 ppmdv by Dry Lo-NOx combustion technology prior to passing through the selective catalytic reduction (SCR) system. NO_x emissions will be reduced to 2.0 ppmvd (at 15% O_2) at the stack exit after passing through the SCR section of the HRSG. CO emissions will be 4.0 ppmvd at 15% reference O_2 at the stack exit (9.0 ppmvd when the plant output is augmented with HRSG duct firing to increase the steam turbine generator output).

Raw materials used at the Spring Canyon plant in addition to natural gas and air are water (to generate the steam) and aqueous ammonia for the selective catalytic (NO_x) reduction process.

The Spring Canyon facility will have a maximum generating capacity of approximately 280 MW at 0^0F and is projected to begin operation in June 2004, or possibly earlier. Maximum estimated annual emissions from the facility will be less than: 66.4 tons of NO_x, 97.5 tons of CO, 70.9 tons of fine particulates (PM_{10}), 67.12 tons of volatile organic compounds (VOCs), 5.3 tons of SO_2 and 5.7 tons of hazardous air pollutants (HAPs). All potential to emit emissions levels are below the ton-per-year PSD thresholds.

Monitoring of emissions from these units will be performed pursuant to 40 CFR 60, Subparts GG and Da and 40 CFR Part 75 and the approval Order.

II. EMISSION SUMMARY

Emissions estimates for NO_x, CO and VOC are based on engineering calculations and emission data provided by the equipment manufacturers. SO_2 emissions are based on sulfur content data from the natural gas supplier. Emissions estimates for HAPs are based on the EPA' s Compilation of Air Pollutant Emission Factors, AP-42 (Supplement F EPA, April 2000). Ammonia slip from the SCR system will be limited to approximately 10 ppmvd, (also based on vendor design data).

The plant steam cycle is designed to be capable of handling full gas turbine base load plus HRSG duct firing down to a minimum ambient temperature of 0^0F. When ambient temperatures drop below this value it will be necessary for the plant to reduce duct firing so as not to exceed the design capacity of the steam system. If it were not reduced, the steam generation capability would continue to increase beyond the design capacity of the steam turbine. System overpressure and a need for steam relief would result. Therefore, as ambient temperatures drop through 0^0F, emission contributions from the duct burner will decrease since the duct-firing rate must be decreased. The zero degree case thus represents the worst-case emissions for this project since it represents the maximum gas turbine base load condition that is coincident with full duct firing capability.

Maximum Hourly Emission Rates from the Gas Turbine and Duct Burner, Maximum plant output at 0^0F:							
Gas Turbine Load	%	100	100	100	100	75	50
GT Fuel Consumption	10^6 x Btu/hr, HHV	1462.3	1462.3	1462.3	1462.3	1097.2	878.6
Duct Burner Fuel	10^6 x Btu/hr,	520	364	32.5	0	0	0

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Consumption	HHV						
Combined GT/DB NOx	#/hr	15.14	13.14	8.9	8.48	6.4	4.96
Combined GT/DB CO	#/hr	**43.80**	39.95	22.35	15.2	11.26	9.01
Combined GT/DB VOC	#/hr	10.40	**15.34**	5.53	2.60	1.80	1.60
Combined GT/DB SO_2	#/hr	1.21	1.12	0.93	0.92	0.69	0.55
Combined GT/DB PM10	#/hr	**16.18**	15.34	10.51	9.43 ·	9.38	9.32
Maximum Stack Emission Concentrations Dry @ 15% O_2 Ref							
Combined NO_x GT/DB	ppmvd	**1.93**	1.81	1.47	1.43	1.45	1.42
Combined CO GT/DB	ppmvd	**9.18**	9.03	6.06	4.21	4.19	4.24
Combined VOC GT/DB	ppmvd	3.81	**6.05**	2.62	1.26	1.17	1.31
Combined SO_2 GT/DB	ppmvd	**0.11**	0.11	0.11	0.11	0.11	0.11

The hourly emission rates in bold letters are the maximum rates for operation of the proposed turbine with duct burner firing natural gas at 100 percent loads based on operation at 0°F, 12.19 ambient pressure, and 25% relative humidity.

2 PM_{10} emissions are condensible and filterable.

GT Gas Turbine

DB Duct Burner

Notes.

- CO = Carbon monoxide
- HHV = high heating value (1011.4 Btu/scf)
- ppmvd = parts per million volume dry
- NO_x = Oxides of nitrogen
- PM_{10} = Particulate matter less than 10 microns in size
- SO_2 = Sulfur dioxide; based on fuel sulfur = 2 gr/1000 cu ft
- VOC = Volatile organic compound

Pollutant	Annual Emissions (tpy)	GT + DB Emissions (lb/hr)	GT only Emissions (lb/hr)	Emission Factor Reference
Criteria Pollutants				

Nitrogen Oxides	63.5	14.5	7.84	Vendor
Carbon Monoxide	97.5	42.1	13.52	Vendor
Sulfur Dioxide	4.9	1.1	0.83	Questar S data
VOCs (Hydrocarbons)	44.7	10.2	2.40	Vendor
Particulate Matter, PM_{10} [3]	70.9	16.1	9.49	Vendor
Hazardous Air Pollutants (HAPs)				
1,3 Butadiene	0.017	0.004		4
Acetaldehyde	0.015	0.035		5
Acrolein	0.015	0.003		5
Benzene	**0.17**	0.04		5
Ethylbenzene	**1.35**	0.30		5
Formaldehyde	**1.51**	0.346		5
Naphthalene	0.01	0.002		5
PAH	0.002	0.0005		5
Propylene Oxide	1.20	0.27		5
Toluene	**1.12**	0.25		5
Xylenes	**0.26**	0.06		5
	5.7	1.31		

1 The emissions values provided in the tables are the cumulative emissions for both turbine and duct burner or gas turbine only.

2 The hourly emission rates are the maximum rates at 100 percent loads based on operation at 59°F, 12.19 psia pressure and 45% relative humidity.

3 PM_{10} emissions are condensible and filterable.

4 AP-42

5 Ventura County (CA) Air Pollution Control District

Notes:

- CO = Carbon monoxide
- tons/yr = tons per year
- lb/hr = pounds per hour
- NOx = Oxides of nitrogen
- PM_{10} = Particulate matter less than 10 microns in size
- SO_2 = Sulfur dioxide; based on fuel sulfur = 2 gr/1000 cu ft
- Tpy = tons per year
- VOC = Volatile organic compound
- GT = Gas turbine
- DB = Duct Burner

The emissions from entire Sources will be as follows:

Pollutant	Current Emissions tons/year	Emission Increases tons/year	Total Emissions tons/year
PM_{10}	0.00	70.90	70.90
SO_2	0.00	5.30	5.30
NO_x	0.00	66.40	66.40
CO	0.00	97.5	97.5
VOC	0.00	67.12	67.12
HAPs			
Formaldehyde	0.00	1.51	1.51
Ethylbenzine	0.00	1.35	1.35
Propylene Oxide	0.00	1.20	1.20
Toluene	0.00	1.12	1.12
Miscellaneous HAPs	0.00	0.42	0.42
Total HAPs	0.00	5.70	5.70

III. BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS

UACR R307-401-6 states, "The Executive Secretary shall issue an approval order if he determines through plan review that the following conditions have been met: The degree of pollution control for emissions, to include fugitive emissions and fugitive dust, is at least BACT except as otherwise provided in these regulations".

The following analyses are presented to determine the BACT controls for each criteria pollutant being emitted for this project.

Step 1 - Identify Potential Control Technologies

The following were conducted: A thorough search of the EPA's RACT/BACT/LAER clearinghouse; Federal/state/local NSR permits; control technology vendors; and environmental consultants.

Step 2 - Eliminate Technically Infeasible Options

Technically feasible option means a technology that is available and applicable to the permitee's operations. The analysis is based on chemical, physical and engineering principles or empirical data

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Step 4 - Evaluate Most Effective Controls and Document Results

The factors considered while evaluating the most effective control options are energy impacts, environmental impacts, and economic impacts.

Step 5 - Select BACT

Each of these steps has been conducted for CO, and are
described below. A BACT analysis of NO_x, SO_2, PM_{10}, and VOC has also been conducted.

NO_x Control Analysis

Step 1 – Identify Potential Control Technologies

Potential NO_x control technology options are:

-Selective Catalytic Reduction (SCR) system and Dry Lo-NOx (DLN);
-Xonon
-SCONOx
-DLN only
-SCR only
-Water or Steam Injection

Step 2 - Eliminate Technically Infeasible Options

-Conventional SCR system requires an exhaust temperature in the 400°F to 800°F range, and when combined with Dry Lo-NO_x, achieves 2.0 ppmvd (at 15% O_2) NO_x. No other technology has achieved this level on gas turbines of this size.

-XONON is not available as a control technology for this application. XONON is being developed by Catalytica Combustion Systems, Inc. It is a catalytic combustion system that reduces the production of NOx. Extensive information on the technology's development indicates that the technology has only been tested on small turbines (less than 10 MW) and is not yet used commercially. This technology has not yet been tested on turbines in the size range of this project's turbine.

Catalytica has entered into an agreement with GE to collaboratively develop the technology for installation on GE Frame E-class and F-class turbines. Catalytica cautions potential investors that adaptation of the technology to GE's turbines will require anywhere from 12 to 24 months. In fact, in a comparison of NOx control technologies on the website, Catalytica indicates that the technology is "in process" of being proven in practice. XONON cannot be considered an available technology for this project.

-Another promising developing technology is SCONOx. SCONOx, like SCR system, operates effectively in temperatures ranging from 300°F to 700°F SCONOx has not been demonstrated in practice on gas turbines of this scale.

-Water injection into the combustion process is an option to reduce NOx production. Water or steam injection can be utilized to reduce NOx levels. By injecting water or steam into the flame, flame temperatures are reduced, thereby lowering thermal NOx formation and overall NOx levels. Water or steam injection can reduce NO_x levels by up to 80% (when firing natural gas) and can achieve greater reduction when firing oil. There is a practical limit to the amount of water or steam that can be injected into the flame before flame stability problems are experienced. Additionally, under normal operating conditions, water/steam injection can result in 3-10% efficiency loss. Many times water or steam injection is used in conjunction with other NO_x control methods such as burner modifications or flue gas recirculation. Water or steam injection alone can only achieve NO_x levels of 25 ppm.

-In summary, for gas turbines of this size, SCR (combined with Dry-Lo-NO_x) system is the only viable option to achieve 2.0 ppmvd (15% O_2) NO_x for exhaust temperatures cooled to between 400°F to 850°F. The control effectiveness of any other viable options and possible combinations are presented in Step 3.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

There is only one other proven NO_x reduction control technology combination proven on the large General Electric frame units. A combination of water injection and SCR control can lower emission rates to 5 ppmvd for NO_x.

Step 4 – Evaluate Most Effective Controls and Document Results

For combined-cycle operation, BACT is a combination of Dry Lo-NO_x and SCR system controls for NO_x. Since the top (minimum NOx emissions) alternative is proposed for NO_x, no cost, environmental or energy impact analyses are required.

Step 5 – Select BACT

The final step is to select BACT for the General Electric Frame 7-FA combined cycle operations at Spring Canyon. For the combined cycle GE Frame 7-FA turbine operations, Dry Lo-NOx and SCR system control with a corresponding emission limit of 2.0 ppmvd is proposed as BACT.

BACT Analysis for CO Emissions

Step 1 – Identify All Control Technologies

Only two control technologies have been identified for CO control:

Combustion Controls
CO catalyst

Step 2 – Eliminate Technically Infeasible Options

Both identified control technologies are technically feasible for this project.

Step 3 – Rank Remaining Control Technologies by
Control Effectiveness

-CO catalyst vendors quote guarantee emissions levels of 4.0 ppm. For this project, the turbine vendor has indicated that proper operation of the turbine will result in CO emissions *from the combustor of 4.0 ppmvd (corrected to 15% O2). Thus there is no additional cost* to achieve 4.0 ppm CO on the turbine. This level is below that listed in the California Air Resources Board BACT guidance document (6 ppm).

Control Technology Emission Rate Ranking

Control Technology	CO Emissions (ppmvd at 15% O_2)	Reduction
Combustion Controls	4	NA
CO Catalyst	4	0%

Step 4 – Evaluate Most Effective Controls and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The top-down process requires that the evaluation begin with the most effective technology. The "top" technologies are Combustion Controls or a CO catalyst. Since the top alternative is proposed as BACT for CO, the cost, environmental, and energy impact analyses are not required.

Step 5 – Select BACT

The final step in the top-down BACT analysis process is to select BACT. Good combustion control is proposed as BACT for this project. Good combustion control with CO emissions of 4.0 ppmvd (at 15% O_2) is proposed as BACT for this project. Note: CO emissions will be kept below 9.0 ppm (at 15% O_2) when the turbine is augmented with duct firing.

BACT Analysis for PM_{10} Emissions

Step 1 – Identify Potential Control Technologies

Three control methods have been identified for PM_{10} control in power generation units:

-Electrostatic precipitators (ESPs)
-Fabric filters
-Combustion of pipeline-quality gas (primary) as the primary fuel

Step 2 – Eliminate Technically Infeasible Options

Neither electrostatic precipitators nor fabric filters are considered to be technically feasible options for combined cycle combustion turbines because of the high exhaust flow rates and the low concentration of particulate in the turbine exhaust.

The particle resistivity associated with gas turbine exhaust is a major problem for ESPs. ESPs remove particles by charging the particles and then collecting them on plates. ESP performance is greatly affected by the ability of the particles to accept and maintain a charge. Because of the resistivity of the exhaust particles from gas turbines, ESPs are not an effective control of turbine particulate matter.

BACT control

The only remaining feasible control method is the use of pipeline-quality natural gas as combustion fuel. This option is PM10 BACT for this project.

BACT Analysis for SO_2 Emissions

Step 1 – Identify Potential Control Technologies

Four potential control methods have been identified for SO2 control:

-Wet flue gas desulfurization (FGD) systems;
-Dry FGD systems;
-Spray dryers
-Combustion of pipeline-quality gas as the combustion fuel.

Step 2 - Select BACT

No wet FGD systems, dry FGD systems, nor spray dryers have been applied to the exhaust gases from turbines, and significant technological difficulties are envisioned to apply all of these technologies. The low SO_2 emissions levels inherent with firing natural gas in a turbine constitutes BACT. In a review of the EPA Clearinghouse data, the only control methods for SO_2 with turbines were related to the fuel combusted. Each turbine listed in the database was required to fire either pipeline-quality natural gas or a low sulfur fuel oil.

For this application, BACT for SO_2 is the use of pipeline-quality natural gas as the combustion fuel.

BACT Analysis for VOC Emissions

Step 1 – Identify Potential Control Technologies

A review of EPA's Clearinghouse showed BACT control for combined cycle gas turbine combustion units is combustion of pipeline-quality natural gas as the primary fuel.

Select BACT

Use of only pipeline-quality natural gas as the fuel for the turbine is BACT for VOCs for this project.

IV. APPLICABILITY OF FEDERAL REGULATIONS AND UTAH ADMINISTRATIVE CODES (UAC)

The Notice of Intent submitted is for a new source. At the time of this review the Utah Administrative Code Rules 307 (UAC R307) and federal regulations have been examined to determine their applicability to this Notice of Intent. The following rules have been specifically addressed.

1. R307-101-2, Major Modification - means any physical change in or change in the method of operation of a major source that would result in a significant net emissions increase of any pollutant.

2. R307-107, UAC - Unavoidable breakdown reporting requirements

3. R307-150 Series, UAC - Inventories, Testing and Monitoring. These rules cover emission inventory reporting requirements and require the owner or operator of sources of air pollution to submit an emissions inventory report:

   R307-150. Emission Inventories
   R307-155. Hazardous Air Pollutant
   R307-158. Emission Statement Inventory.

4. R307-201-1(2), UAC - 20% maximum opacity limitation at all emission points. Visible emissions from installations constructed after April 25, 1971, except internal combustion engines, or any incinerator shall be of a shade or density no darker than 20% opacity, except as otherwise provided in these regulations.

5. R307-201-1(9), UAC - Opacity Observation.

6. R307-203-1(1), UAC - Commercial and Industrial Sources. Any coal, oil, or mixture thereof, burned in any fuel burning or process installation not covered by New Source Performance Standards for sulfur emissions shall contain no more than 1.0 pound sulfur per million gross Btu heat input for any mixture of coal nor .85 pounds sulfur per million gross Btu heat input for any oil.

7. R307-205 (UAC) - Emission Standards: Fugitive Emissions and Fugitive Dust.

8. R307-401-10(1), UAC - All sources excluding non-commercial residential dwellings shall install oxides of nitrogen control/low oxides of nitrogen burners or controls resulting from application of an equivalent technology, as determined by the Executive Secretary, whenever existing fuel combustion burners are replaced, unless such replacement is not physically practical or cost effective. The request for an exemption shall be presented to the Executive Secretary for review and approval.

9. R307-403-3, UAC - Every major new source or major modification must be reviewed by the Executive Secretary to determine if a source will cause or contribute to a violation of the NAAQS.

10. R307-403-5(1)(b), UAC - Enforceable offsets of 1.2:1 are required for new sources or modifications that would produce an emission increase greater than or equal to 50 tons per year of any combination of PM_{10}, SO_2, and NO_x.

11. R307-403-5(1)(c), UAC - Enforceable offsets of 1:1 are required for new sources or modifications that would produce an emission increase greater than or equal to 25 tons per year but less than 50 tons per year of any combination of PM_{10}, SO_2, and NO_x.

12. R307-405, UAC - Permits: Prevention of Significant Deterioration of Air Quality (PSD).
    405-1. Definitions
    405-2. Area Designations
    405-3. Area Redesignation
    405-4. Increments and Ceilings
    405-5. Baseline Concentration and Date
    405-6. PSD Areas - New Sources and Modifications
    405-7. Increment Violations
    405-8. Banking of Emission Offset Credit in PSD Areas

13. R307-406, UAC – Visibility

    406-1.(1) The Executive Secretary shall review any new major source or major modification proposed in either an attainment area or area of non-attainment area for the impact of its emissions on visibility in any mandatory Class I area.

14. R307-410, UAC - Permits: Emissions Impact Analysis (Air Quality Modeling)

15. R307-413, UAC - Permits: Exemptions and Special Provisions
    413-1. Definitions and General Requirements
    413-2. Small Source Exemptions - De minimis Emissions
    413-3. Flexibility Changes
    413-4. Other Exemptions
    413-5. Replacement-in-Kind Equipment

413-6. Reduction of Air Contaminants
413-7. Exemption from Notice of Intent Requirements for Used Oil Fuel Burned for Energy Recovery
413-8. De minimis Emissions From Air Strippers and Soil Venting Projects
413-9. De minimis Emissions From Soil Aeration Projects.

16. R307-420, UAC - Permits: Ozone Offset Requirements in Davis and Salt Lake Counties.

17. 40 CFR, Part 50 - National Ambient Air Quality Standards (NAAQS). The following areas are Non-attainment areas:

PM_{10} Salt Lake and Utah Counties, and the city of Ogden
SO_2 Salt Lake County and The Oquirrh Mountains above 5,600 feet in Eastern Tooele County
CO Provo

The following areas are Maintenance Areas:

Ozone Salt Lake and Davis Counties
CO Ogden and Salt Lake City

18. 40 CFR 60.15, Definition of Reconstruction - the replacement of components of an existing facility to such an extent that:

A. The fixed capital cost of the new components exceeds 50% of the fixed capital cost that would be required to construct a comparable entirely new facility and

B. It is technologically and economically feasible to meet the applicable standards set forth in this part.

19. R-307-405-1. Permits: Prevention of Significant Deterioration of Air Quality

Since the proposed turbine belongs to a source category for "Fossil fuel-fired steam electric plants of more than 250 x 10^6 Btu/hr heat input", a potential to emit of any air pollutant of 100 tons would qualify this source to be a major PSD source.

This source has proposed emissions for any air pollutant of less than 100 tons; therefore it does not qualify as a major PSD source and it is not a subject to PSD applicability. Thus the provisions of UAC R307-405 do not apply to this project. Thus the facility, as proposed in this project, is considered a PSD syntactic minor source.

20. Offsets: General Requirements

The project location is in Juab County, which is an attainment area for all pollutants. Impact from this source was evaluated and modeling analysis showed that the emissions from this source would not cause an increase greater that the increments given in UAC

R307-403-3. Review of Major Sources of Air Quality Impact.

Therefore, the proposed project did not trigger offsets requirements. Thus the provisions of UAC R307-403-3 (3) do not apply.

R307403-5. Offsets: PM10 Nonattainment Area

The impacts of any combination of PM_{10}, NO_x and SO_2 along the Utah County line are below 1.0 :g/m^3 for an annual averaging period and below 3.0 :g/m3 for a 24-hour averaging period. Thus the provisions of UAC R307-403-5 do not apply.

21. Air Quality Impact Analysis

In the review of the Applicant's air quality impact analysis was evaluated including the information, data, assumptions and modeling results used to determine if the facility would be in compliance with State and Federal concentration standards, increments and/or levels. The information, data, assumptions, and modeling results submitted by the Applicant are contained in the report entitled "*Air Dispersion Modeling Results for the Spring Canyon, Utah, Combined Cycle Power System*," dated July 25, 2002.

Applicable Rule(s)

Utah Air Quality Rules (UAC):

R307-401-6	Condition for Issuing an Approval Order
R307-410-2	Use of Dispersion Models
R307-410-3	Modeling of Criteria Pollutants in Attainment Areas
R307-410-4	Documentation of Ambient Air Impacts for Hazardous Air Pollutants
R307-410-5	Stack Heights and Dispersion Techniques
R307-403-5	Offsets: PM10 Non-attainment Areas

Modeling Methodology

Applicability

Since the emissions have increased above modeling threshold levels for NO_x, CO, PM_{10}, and formaldehyde, an air quality modeling assessment consistent with R307-410-2 was performed.

Assumptions

Topography/Terrain

The Plant is at an elevation of approximately 5150 feet with nearby significant terrain features that will affect concentration predictions.

a. Zone· 12

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b. Approximate Location:

UTM (NAD27): 423178.88 meters East, 4410214.5 meters North

2. Urban or Rural Area Designation

After a review of the appropriate 7.5 minute quadrangles, it was concluded that the area is "rural" for air modeling purposes.

3. Ambient Air

It was determined that the Plant boundary used in the AQIA meets the State's definition of ambient air.

4. Building Downwash

The Applicant used the U.S. Environmental Protection Agency (USEPA) Building Profile Input Program (BPIP) to determine good engineering practice (GEP) stack heights and building dimensions for input into the ISCST3 model. Parameters from the stacks and dimensions from buildings were input into the BPIP. It was assumed that ground level elevations for the stacks and buildings were the same. The output from BPIP showed all stacks to be less than their GEP formula stack height, thereby, required a wake effect evaluation. Since the stack is higher than 65 meters, the stack height must be in accordance with the GEP stack height requirements. Section 12 of this review contains a more in-depth review of the stack height justification used in the AQIA.

5. Meteorology

Five years of off-site surface and upper air data was used in the analysis consisting of the following:

Surface/Upper Air - Salt Lake City Intl. Airport-NWS, 1995-1999

6. Background

The NO_2 background concentration of 10 $\mu g/m^3$, was estimated based on review of ambient air data monitored in similar rural areas. Similarly, the PM_{10} background concentration of 28 $\mu g/m^3$ 24-hour average and 10 $\mu g/m^3$ annual average were estimated based on review of ambient air data monitored in rural areas. The CO background concentrations of 1 ppm 1-hour average and 1 ppm 8-hour average, were also estimated based on review of ambient air data monitored in rural areas.

7. Receptor and Terrain Elevations

The modeling domain used by the Applicant consisted of 2881 receptors including property boundary receptors. This area of the state contains mountainous terrain and the modeling domain has simple and complex terrain features in the near and far fields. Therefore, receptor points representing actual terrain elevations from the area were used in the analysis. Receptors were also concentrated along the Juab-Utah county line in order to estimate impacts related to the offset requirements for the Utah County PM_{10} non-attainment area.

8. Model and Options

The US EPA and the State accepted Industrial Source Complex Short Term - Version 3 (ISCST3) model was used by the Applicant to predict air pollutant concentrations under a simple/complex terrain/wake effect situation. In quantifying concentrations, the regulatory default option was selected by the Applicant.

9. Ambient Ratio Method (ARM)

The Applicant used the EPA default NO_2/ NO_X ratio of 0.75 to obtain annual NO_2 concentrations from the model predicted NO_X concentrations.

10. Air Pollutant Emission Rates

	Expected Maximum Air Pollutant Emission Rates at ISO Conditions							
	NO_X		PM_{10}		SO_2		CO	Formaldehyde
Source	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(lb/hr)
E-STACK	15,14	66.31	16.18	70.518	1.11	4.818	39.4	0.3463

11. Source Location and Parameters

Point Sources

	UTM Coordinates		Stack Parameters				
Source	Easting (X) (m)	Northing (Y) (m)	Base Elevation (ft)	Height (ft)	Gas Temperature (°F)	Exit Velocity (ft/s)	Diameter (ft)
E-STACK	423178.9	4410215	5150	295.3	230	80.00	17.00

12. GEP Stack Height Evaluation

The facility proposes to install a stack that is taller than 65 meters. As required under R307-410-5, the degree of emission limitation required of any source for control of any air

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contaminant to include determinations made under R307-401, R307-403 and R307-405, must not be affected by so much of any source's stack height that exceeds good engineering practice or by any other dispersion technique.

For this facility, the GEP stack height is defined by $H_g = H+1.5L$. Where H_g= GEP stack height measured from the ground-level elevation at the base of the stack; H=height of nearby structure(s) measured from the ground-level elevation at the base of the stack; L=lesser dimension (height or projected width) of nearby structure(s).

Based on the building dimensions supplied by the applicant, the following dimensions were used to determine H_g:

H = 36.58 meters (HRSG building)
L = 36.58 meters (HRSG building projected width=43.84 meters, height=36.58 meters)

Therefore, H_g = 36.58 + 1.5 * 36.58 = 91.45 meters.

Since the proposed stack is 90 meters, the stack height is justified and does not exceed GEP formula height.

RESULTS AND CONCLUSIONS

A. National Ambient Air Quality Standards

The below table provides a comparison of the predicted total air quality concentrations with NAAQS. The predicted total concentrations are less than the NAAQS.

Air Pollutant	Period	Prediction ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Percent NAAQS
NO_2	Annual	0.172196	10	10.1722	100	10.17%
PM_{10}	24-Hour	1.66372	28	30	150	19.78%
	Annual	0.254929	10	10	50	20.51%
CO	1-Hour	29.57913	1,111	1,141	40,000	2.85%
	8-Hour	11.08169	1,111	1,122	10,000	11.22%

B. Hazardous Air Pollutant Demonstration

The below table summarizes the predicted HAPS concentrations and compares those values with the State of Utah acceptable health levels or toxic screening levels. All predicted concentrations were determined to be less than the HAPS specific toxic screening levels.

Air	Period	Prediction	TSL	Percent

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Pollutant		(µg/m³)	(µg/m³)	TSL
Formaldehyde	1-Hour	0.259981	37	0.70%

Formaldehyde: 1-Hour TSL = TLV/10

C. Air Quality Increments - Class II

The below table provides a comparison of the predicted concentration, which only includes increment consuming emissions from the Spring Canyon facility. The predicted concentration is less than the Class II air quality increment.

Air Pollutant	Period	Prediction (µg/m³)	Increment (µg/m³)	Percent PSD
NO_2	Annual	0.1721955	25	0.69%
PM_{10}	24-Hour	1.6637196	30	5.55%
	Annual	0.2549285	17	1.50%

D. Offsets for PM10 Non-attainment areas

The below table summarizes the combined NOx+SO2+PM10 concentrations predicted within the Utah County PM10 non-attainment area, and compares those values with the State of Utah acceptable levels. All predicted concentrations were determined to be less than the offset trigger concentration; therefore, no offsets are required.

Air Pollutant	Period	Prediction (µg/m³)	Allowed (µg/m³)	Percent
(NO2+PM10+SO2)	Annual	0.41	1	40 71%
	24-Hour	2.63	3	87.56%

V. Modeling Recommended Permit Conditions

The following suggested permit language should be included under the Terms and Conditions:

A. Gas Turbine, Stack Height - no less than 90 meters as measured from the ground.

B. Gas Turbine, Stack Exit Diameter - not greater than 17 feet.

RECOMMENDED APPROVAL ORDER CONDITIONS

General Conditions:

1. This Approval Order (AO) applies to the following company:

   Corporate Office Location

   Spring Canyon Energy
   PO Box 774000-359
   Steamboat Springs, Colorado 80477
   Phone Number (970) 871-6223
   Fax Number (970) 871-6234

   The equipment listed in this AO shall be operated at the following location:

   From Salt Lake take I-15 south approximately 77 miles to Hwy 54. Take exit and proceed west through Mona. Go ½ mile north on Goshen Canyon Road; Plant site is ½ mile to the west.
   Juab County

   Universal Transverse Mercator (UTM) Coordinate System: UTM Datum NAD27
   4,410.042 kilometers Northing, 422.81 kilometers Easting, Zone 12

2. All definitions, terms, abbreviations, and references used in this AO conform to those used in the Utah Administrative Code (UAC) Rule 307 (R307) and Title 40 of the Code of Federal Regulations (40 CFR). Unless noted otherwise, references cited in these AO conditions refer to those rules.

3. The limits set forth in this AO shall not be exceeded without prior approval in accordance with R307-401.

4. Modifications to the equipment or processes approved by this AO that could affect the emissions covered by this AO must be reviewed and approved in accordance with R307-401-1.

5. All records referenced in this AO or in applicable NSPS standards, which are required to be kept by the owner/operator, shall be made available to the Executive Secretary or Executive Secretary's representative upon request, and the records shall include the two-year period prior to the date of the request. Records shall be kept for the following minimum periods:

6. Emission inventories Five years from the due date of each emission statement or until the next inventory is due, whichever is longer.

   All other records Two years

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7. Spring Canyon Energy, LLC shall install and operate one natural gas fueled combined cycle turbine generator set with duct burner and ambient air inlet chiller with maximum combined rating of approximately 280 MW, one diesel fired emergency generator rated at 700 bhp, one diesel fired fire pump rated at 250 bhp, and miscellaneous small diesel fuel storage tanks (each with storage capacity of less that 10,000 gallons) at the Spring Canyon Energy power generating facility in accordance with the terms and conditions of this AO, which was written pursuant to Spring Canyon Energy, LLC's Notice of Intent submitted to the Division of Air Quality (DAQ) on August 13, 2002 and additional information submitted to the DAQ on August 15, 2002, August 29, 2002, September 26, 2002, October 10, 2002

8. The approved installations shall consist of the following equipment or equivalent*:

A. One (1) General Electric Frame 7-FA (PG7241FA)* gas turbine, with one (1) duct fired HRSG, and one (1) steam turbine generator set.

The gas turbine is provided with ambient inlet air chiller coils. The Heat Recovery Steam Generator (HRSG) is equipped with a Selective Catalytic Reduction System for abatement of NO_x emissions from the Duct Burner and the Gas Turbine. Continuous Emission Monitoring System (CEMS) for the HRSG stack is provided for monitoring emissions from the gas turbine and duct burners. The power generating facility has the following characteristics:

Maximum plant site rated output at 100% Load.	
0^0F, 12.19 psia and 25% relative humidity:	280 MW
Heat input at the baseload, ISO (59^0F, site elevation):	1,472.9 x Btu/hr (HHV)
Maximum gas turbine firing rate:	1,621.5 x 10^6 Btu/hr (HHV)

B. One (1) duct burner (subject to 40 CFR 60, Subpart Da)
Maximum firing rate: 520 x 10^6 Btu/hr (HHV)

C. One (1) Diesel Fired Emergency Generator rated at 700 bhp

D. One (1) Diesel Fired Emergency Fire Pump rated at 250 bhp

E. Miscellaneous diesel fuel storage tanks, each individual tank storage capacity is less than 10,000 gallons

F. One (1) Dry type air-cooled condenser.**

* Equivalency shall be determined by the Executive Secretary.

** This equipment is listed for informational purposes only. There are no emissions from this equipment.

9 Spring Canyon Energy, LLC shall notify the Executive Secretary in writing when the

installation of the equipment listed in Condition #8 has been completed and is operational, as an initial compliance inspection is required. To insure proper credit when notifying the Executive Secretary, send your correspondence to the Executive Secretary, attn: Compliance Section.

If construction and/or installation have not been completed within eighteen months from the date of this AO, the Executive Secretary shall be notified in writing on the status of the construction and/or installation. At that time, the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation and may revoke the AO in accordance with R307-401-11.

Limitations and Tests Procedures

10. Visible emissions from the following emission points shall not exceed the following values:
    A. Natural gas combustion exhaust stacks - 10% opacity
    B. All other points - 20% opacity

    Opacity observations of emissions from stationary sources shall be conducted according to 40 CFR 60, Appendix A, Method 9.

11. The following limits shall apply:

    A. Gas Turbine, Stack Height - no less than 295.27 feet (90 meters) as measured from the ground
    B. Gas Turbine, Stack Exit Diameter - not greater than 17 feet

12. Combined source wide CO emissions shall be no greater than 97.5 tons per rolling 12-month period.

    Compliance to the above emission limitation shall be determined as follows:

    CO from the gas turbine and the duct burner shall be obtained from CEMS recorded data (conversion from ppmvd into pounds shall be done using the procedure in the EPA reference Method 19 or other procedure approved by the Executive Secretary).
    CO from the emergency generators shall be obtained by multiplying the engine rating, recorded hours of operation and emission factors from the Vendor data if available or EPA's Compilation of Air Pollutant Emission Factors, AP-42

    To determine compliance with a rolling 12-month total the owner/operator shall calculate a new 12-month total by the twentieth day of each month using data from the previous 12 months. Records of hours of operation and emissions rates shall be kept for all periods when the plant is in operation. For emergency generator and the emergency fire pump hours of operation shall be determined by supervisor monitoring and maintaining of an operations log. The records of consumption/production shall be kept on a daily basis.

13 Combined emission rate of PM_{10}+ NO_x + SO_2 shall not be greater than of 776.16 lb per any

rolling 24-hour average at the stack exhaust (turbine and the duct burner)
Compliance to the above emission limitation shall be determined as follows:

NO_x from the gas turbine and the duct burner shall be obtained from CEMS recorded data (conversion from ppmvd into pounds shall be done using the procedure in EPA reference Method 19 or other procedure approved by the Executive Secretary).
PM_{10} from the gas turbine and the duct burner shall be from the latest emission test recorded data or from Vendor data if testing is not required.
SO_2 from the gas turbine and the duct burner shall be from the latest emission test or if testing is not required by the other alternative method as approved by the Executive Secretary or Administrator.

To determine compliance with rolling 24-hour total the owner/operator shall calculate average hourly rate and average them over 24-hour period. New 24-hour total shall be calculated by the noon of the next day. Records of hours of operation and emissions rates shall be kept for all periods when the plant is in operation.

15. Emergency generators shall be used for electricity producing operation only during the periods when electric power from the public utilities is interrupted, or for regular maintenance of the generators. Records documenting generator usage and fire pump usage shall be kept in a log and they shall show the date the generator was used, the duration in hours of the generator usage, and the reason for each generator usage.

Fuels

13. The owner/operator shall use only natural gas, as fuel in the gas turbine and duct burner; fuel oil #2 or better in the emergency generator and the fire pump.

14. The sulfur content of any fuel oil or diesel burned shall not exceed:

A. 0.5 percent by weight for diesel fuels

The sulfur content shall be determined by ASTM Method D-4294-89 or approved equivalent. Certification of other fuels shall be either by USA Power, LLC=s own testing or test reports from the fuel marketer

Federal Limitations and Requirements

15. In addition to the requirements of this AO, all applicable provisions of 40 CFR 60, New Source Performance Standards (NSPS) Subpart A, 40 CFR 60.1 to 60.18, Subpart GG, 40 CFR 60.330 to 60.334 (Standards of Performance for Stationary Gas Turbines) and Subpart Da, 40 CFR 60.40a to 60.49a (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978) apply to this installation.

16. In addition to the requirements of this AO, all applicable provisions of 40 CFR Part 72, 73, 75, 76, 77, and 78 Federal regulations for the Acid Rain Program under Clean Air Act Title

IV apply to this installation.

Limitations and Tests Procedures

17. Emissions to the atmosphere from the indicated emission points shall not exceed the following rates and concentrations:

Source: Turbine GE Frame 7-FA (PG7241FA) and Duct Burner Exhaust Stack

Pollutant	ppmvd* (15% O_2 dry) (30-day rolling average)	ppmvd** (15% O_2 dry) (30-day rolling average)	ppmvd (15% O_2 dry)
NO_x	2	2	***
CO	4	9	NA

*Emissions concentrations from the gas turbine under steady state operation not including startups and shutdowns
**Combined emissions concentrations from the gas turbine and the duct burner under steady state operation not including startups and shutdowns
***Emissions concentration from the gas turbine (in accordance with 40 CFR 60 Subpart GG requirements)

18. Emissions testing, and compliance monitoring to the atmosphere from the duct burner shall be performed in accordance with all applicable provisions of 40 CFR 60, New Source Performance Standards (NSPS) Subpart A and Subpart Da, 40 CFR 60.40a to 60.49a (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978) apply to this installation.

19. Stack testing to show compliance with the emission limitations stated in the above condition shall be performed as specified below

A.

Emissions Point	Pollutant	Testing Status	Test Frequency
(Gas turbine only)	NO_x	*,**	CEMs
	CO	*	CEMs
(Gas turbine & duct burner)	NO_x	*	CEMs
	CO	*	CEMs

*Initial compliance testing shall be demonstrated by Relative Accuracy Test Audit.
**Initial compliance testing for NO_x for the gas turbine shall be performed in accordance with the 40 CFR 60 Subpart GG.
Initial compliance testing for the Duct Burner shall be performed in accordance with the 40 CFR 60 Subpart Da. Initial compliance testing shall be performed within 60 days after achieving the maximum production rate at which the affected facility will be operated and in no case later than 180 days after the start up of a

new emission source.

Monitoring - Continuous Emissions Monitoring

20. The owner/operator shall install, calibrate, maintain, and operate a continuous monitoring system for measuring nitrogen oxides, oxygen and carbon monoxide emissions discharged to the atmosphere from each turbine stack and record the output of the system. The monitoring system shall be used for measuring and determining compliance. The continuous monitoring system shall comply with applicable provisions of UAC, R307-170 and applicable Federal regulations for the Acid Rain Program under Clean Air Act Title IV.

21. Spring Canyon Energy, LLC shall submit for review and Executive Secretary approval CEMs monitoring plan 45 days before the turbine become operational. The plan shall address the number of monitors to be used, the method of measuring the rate in tons per hour, and the method of calculating emissions during the CEMs breakdowns.

Records & Miscellaneous

22. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any equipment approved under this Approval Order including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Executive Secretary which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. All maintenance performed on equipment authorized by this AO shall be recorded.

23. The owner/operator shall comply with R307-150 Series. Inventories, Testing and Monitoring:

24. The owner/operator shall comply with R307-107. General Requirements: Unavoidable Breakdowns.

The Executive Secretary shall be notified in writing if the company is sold or changes its name.

Under R307-150-1, the Executive Secretary may require a source to submit an emission inventory for any full or partial year on reasonable notice.

This AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including R307.

A copy of the rules, regulations and/or attachments addressed in this AO may be obtained by contacting the Division of Air Quality. The Utah Administrative Code R307 rules used by DAQ, the Notice of Intent (NOI) guide, and other air quality documents and forms may also be obtained on the Internet at the following web site:

http://www.deq.state.ut.us/eqair/aq_home.htm

The annual emission estimations below include point source and do not include fugitive emissions, fugitive dust, road dust, tail pipe emissions, etc. These emissions are for the purpose of determining the applicability of Prevention of Significant Deterioration, non-attainment area, Maintenance area, and Title V source requirements of the R307. They are not to be used for determining compliance.

The Potential To Emit (PTE) emissions for this source (the entire plant, or specify what portion) are currently calculated at the following values:

Pollutant	Tons/yr
PM_{10}	70.9
SO_2	5.3
NO_x	66.4
CO	97.5
VOC	67.12
HAPs	
Acetaldehyde	0.015
Acrolein	0.015
1,3 Butadiene	0.017
Benzene	0.17
Ethylbenzene	1.35
Formaldehyde	1.51
Naphthalene	0.01
PAH	0.002
Propylene Oxide	1.20
Toluene	1.12
Xylenes	0.26
· Totals	5.7

700 N.E. Multnomah, Suite 550
Portland, Oregon 97232

PACIFICORP
PACIFIC POWER UTAH POWER

August 22, 2002

David Graeber
USA Power Partners LLC
10440 N. Central Expressway, #1400
Dallas, Texas 75231

Dear Mr. Graeber:

Pursuant to the May 9, 2002 Interconnection Study, PacifiCorp has identified the facilities required to interconnect USA Power Partners LLC's ("USA Power") proposed 550 MW generation facility with PacifiCorp's 345 kV Mona Substation and the estimated cost for the required Network Upgrades (modifications to PacifiCorp's transmission system) and certain required Interconnection Facilities (Interconnection Facilities are those facilities that will be used only by USA Power Partners). The estimated cost is based on the generating facility's proposed on-line date of June 1, 2004.

PacifiCorp's estimated cost to design, procure and construct these facilities is $2,678,732. Note, in reference to the attached one-line diagram, the estimate does not include the transmission line from the USA Substation to the Mona Substation and the four 345 kV breakers at the USA Substation.

Mona Substation

Design, furnish and install metering, communications, protection and controls and substation equipment at PacifiCorp's Mona Substation for a line position to interconnect USA Power's 345 kV line from the generation facility with PacifiCorp's transmission system.

Metering

Installation		$ 6,682
Material		3,721
Design/Project Support		2,500
	Total	$ 12,963

Communications

Installation		$ 19,064
Material		25,512
Design/Project Support		20,060
	Total	$ 64,636

Protection and Controls

Installation		$ 43,262
Material		30,935
Design/Project Support		94,800
	Total	$168,997

Substation Equipment

Installation		$ 193,716
Material		797,722
Design/Project Support		274,900
	Total	$1,266,388

USA Power Substation

Design, furnish and install metering, communications (includes fiber optic cable on USA Power structures, and RTU), protection and control facilities at USA Power's generator substation, for the 345 kV interconnection.

Metering

Installation		$ 28,630
Material		177,521
Design/Project Support		75,500
	Total	$281,651

Communications

Installation		$ 85,236
Material		205,533
Design/Project Support		71,660
	Total	$362,429

Protection & Controls

Installation		$ 57,437
Material		34,636
Design/Project Support		45,320
	Total	$137,393

Project Totals

Installation		$ 434,027
Material		1,275,630
Design/Project Support		584,800
Overheads		263,863
Escalation		120,412
	Total	$2,678,732

If USA Power desires to continue with the project, please sign in the space provided below and return this Letter of Intent to me. Upon PacifiCorp's receipt of the executed Letter of Intent, the project will be submitted for PacifiCorp management approval. Following management approval, PacifiCorp will coordinate with USA Power to develop a definitive scope of work for both USA Power and PacifiCorp, project schedule and cash flow to be incorporated into a Facilities Construction Agreement for execution by USA Power. PacifiCorp will commence completion of the project upon receipt of the executed Facilities Construction Agreement and required prepayment.

If you have any questions, please call Larry Soderquist at (503) 813-6102 or Dan Johannsen at (503) 813-5735.

Sincerely,

David B. Cory
Director, Transmission Services

Attachment

Accepted and Agreed to:

USA Power Partners LLC

By: ____________________

Date: 9/12/02

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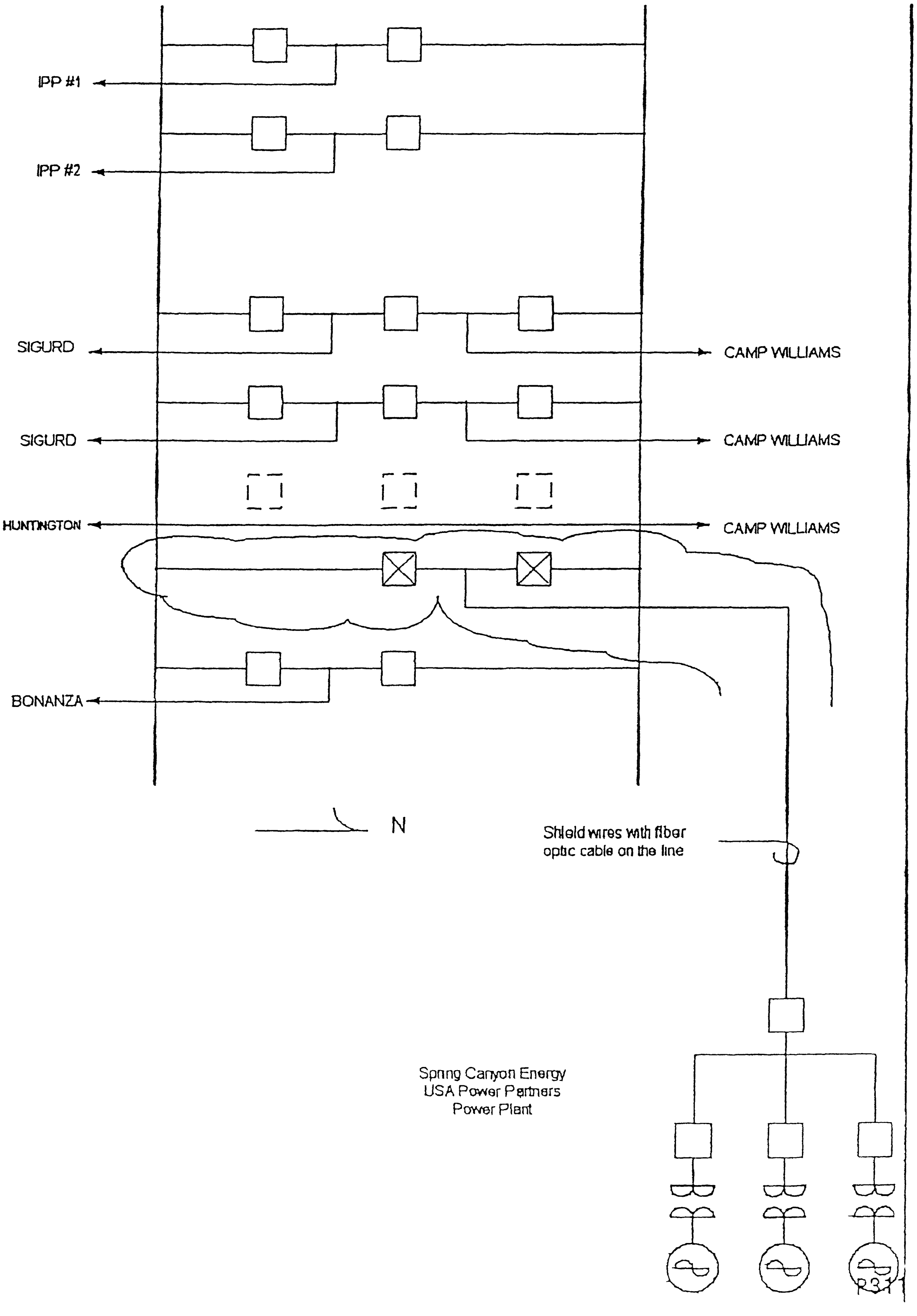
IPP #1
IPP #2
SIGURD
CAMP WILLIAMS
SIGURD
CAMP WILLIAMS
HUNTINGTON
CAMP WILLIAMS
BONANZA
N
Shield wires with fiber optic cable on the line
Spring Canyon Energy
USA Power Partners
Power Plant
R311

99806

A. Questar Letter Regarding Natural Gas Service

QUESTAR

Questar Regulated Services Co.
Questar Gas • Questar Pipeline • Questar Energy Services
180 East 100 South
P.O. Box 45360
Salt Lake City, UT 84145-0360
Tel 801 324 2938 • Fax 801 324 2980

Gary A. Schmitt, P.E.
Director, Marketing

September 9, 2002

Mr. F. David Graeber
Principal
USA Power Partners LLC
10440 N. Central Expressway #1400
Dallas, TX 75231

Ref: Natural Gas Service for Spring Canyon Energy LLC

Dear Dave:

Over the last several months Questar Pipeline Company (Questar Pipeline) representatives have had numerous discussions with members of USA Power Partners LLC (USA Power) regarding USA Power's 530 MW natural gas fired power plant to be located in Juab County, Utah, approximately 85 miles south of Salt Lake City. Questar Pipeline has been told by USA Power that the power plant, which is known as Spring Canyon Energy LLC (Spring Canyon), is in the final stages of development and is expected to be operational as early as June 2004. The proposed location of the power plant is approximately 0.75 miles from the Mona Substation and approximately 10 miles to the south of Questar's Mainline 104.

It is our understanding that the power plant, when optimally fired, will require up to approximately 100 million cubic feet (or decatherm equivalent) of gas per day. Questar is very interested in providing natural gas transportation service to the plant, by building, owning and operating a 10-mile lateral off of our Mainline 104. Upon request, Questar Pipeline will prepare a formal proposal to USA Power confirming our ability to provide natural gas transportation service to Spring Canyon and the costs associated with such service.

USA Power has advised us that they have met with our unregulated affiliate, Questar Energy Trading Company (QET) about supplying the natural gas for the facility.

Both Questar Pipeline and the Spring Canyon project are strategically located to take advantage of prolific Rocky Mountain natural gas production and natural gas cost savings over other national supplies. In fact, since 1972, gas production in the Rocky Mountain region has grown by 518%, while gas reserves in other regions of the country have continued to decline. Questar Pipeline believes that access to Rocky Mountain natural gas supplies provides a strategic advantage to electric generation facilities in its service area. We appreciate the opportunity to provide a proposal for natural gas transportation service in the near future, and look forward to continued discussions with USA Power.

Sincerely,

Gary A Schmitt

Gary A. Schmitt

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B. Rocky Mountain Natural Gas Pricing Analysis

Summary of Average Annual Inside FERC Gas Prices

	QPC Rocky Mtns.	NPC Rocky Mtns.	KRGT Wyoming	CIG Rocky Mtns.	SoCAL	Henry Hub
1997 Average	$1.98	$2.00	$1.99	$1.99	Prices not recorded	
1998 Average	$1.79	$1.81	$1.81	$1.80	Prices not recorded	
1999 Average	$1.97	$2.04	$2.04	$2.01	$2.32	$2.28
2000 Average	$3.32	$3.40	$3.44	$3.35	$4.94	$3.89
2001 Average	$3.46	$3.66	$3.64	$3.50	$8.09	$4.27
2002 MTD Average	$1.83	$1.95	$1.95	$1.88	$2.81	$2.89

Inside FERC Monthly Gas Prices

Month	QPC Rocky Mtns.	NPC Rocky Mtns.	KRGT Wyoming	CIG Rocky Mtns.	SoCAL	Henry Hub
Jan-02	$2.19	$2.35	$2.36	$2.26	$2.62	$2.61
Feb-02	$1.60	$1.73	$1.72	$1.70	$2.02	$2.03
Mar-02	$1.85	$1.97	$1.97	$1.85	$2.13	$2.12
Apr-02	$2.67	$2.85	$2.86	$2.71	$3.42	$3.40
May-02	$2.09	$2.26	$2.27	$2.18	$3.22	$3.36
Jun-02	$1.53	$1.60	$1.60	$1.56	$2.88	$3.37
Jul-02	$1.23	$1.26	$1.26	$1.20	$3.30	$3.26
Aug-02	$1.47	$1.59	$1.59	$1.59	$2.82	$2.95
Sep-02						
Oct-02						
Nov-02						
Dec-02						
2002 MTD Average	$1.83	$1.95	$1.95	$1.88	$2.81	$2.89

Inside FERC Monthly Gas Prices						
Month	QPC Rocky Mtns.	NPC Rocky Mtns.	KRGT Wyoming	CIG Rocky Mtns.	SoCAL	Henry Hub
Jan-99	$1.73	$1.82	$1.80	$1.75	$2.04	$1.80
Feb-99	$1.58	$1.63	$1.64	$1.61	$1.83	$1.81
Mar-99	$1.45	$1.51	$1.51	$1.49	$1.71	$1.64
Apr-99	$1.43	$1.54	$1.54	$1.53	$1.78	$1.88
May-99	$1.90	$2.00	$1.99	$1.98	$2.22	$2.35
Jun-99	$1.85	$1.94	$1.94	$1.93	$2.22	$2.23
Jul-99	$1.92	$1.99	$2.00	$1.97	$2.38	$2.38
Aug-99	$2.12	$2.18	$2.18	$2.16	$2.58	$2.62
Sep-99	$2.48	$2.56	$2.56	$2.52	$2.93	$2.90
Oct-99	$2.34	$2.39	$2.39	$2.35	$2.71	$2.55
Nov-99	$2.82	$2.86	$2.86	$2.83	$3.07	$3.06
Dec-99	$1.99	$2.10	$2.10	$2.04	$2.37	$2.14
1999 Average	$1.97	$2.04	$2.04	$2.01	$2.32	$2.28
Jan-00	$2.15	$2.19	$2.19	$2.15	$2.38	$2.36
Feb-00	$2.33	$2.37	$2.38	$2.34	$2.55	$2.61
Mar-00	$2.30	$2.36	$2.35	$2.31	$2.59	$2.61
Apr-00	$2.62	$2.69	$2.70	$2.65	$3.02	$2.88
May-00	$2.62	$2.72	$2.74	$2.61	$3.03	$3.08
Jun-00	$3.41	$3.65	$3.61	$3.62	$4.30	$4.37
Jul-00	$3.66	$3.70	$3.95	$3.70	$4.95	$4.03
Aug-00	$2.92	$3.09	$3.12	$3.04	$4.49	$3.83
Sep-00	$3.25	$3.41	$3.47	$3.36	$6.49	$4.62
Oct-00	$4.17	$4.29	$4.31	$4.19	$5.98	$5.22
Nov-00	$4.28	$4.35	$4.37	$4.31	$5.20	$4.50
Dec-00	$6.14	$6.01	$6.07	$5.95	$14.26	$6.58
2000 Average	$3.32	$3.40	$3.44	$3.35	$4.94	$3.89
Jan-01	$8.58	$8.76	$8.77	$8.63	$16.39	$9.98
Feb-01	$6.42	$6.59	$6.41	$6.31	$12.51	$6.22
Mar-01	$4.79	$4.88	$4.86	$4.72	$12.53	$5.03
Apr-01	$4.50	$4.57	$4.57	$4.49	$12.51	$5.35
May-01	$3.87	$4.10	$4.11	$3.91	$14.97	$4.87
Jun-01	$2.42	$2.61	$2.61	$2.43	$10.00	$3.74
Jul-01	$1.74	$2.03	$2.03	$1.75	$4.76	$3.16
Aug-01	$1.89	$2.27	$2.27	$2.03	$3.75	$3.19
Sep-01	$1.90	$2.10	$2.08	$1.99	$2.65	$2.34
Oct-01	$0.95	$1.24	$1.23	$1.05	$1.75	$1.86
Nov-01	$2.38	$2.59	$2.64	$2.54	$2.95	$3.16
Dec-01	$2.02	$2.16	$2.13	$2.13	$2.27	$2.28
2001 Average	$3.46	$3.66	$3.64	$3.50	$8.09	$4.27

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Inside FERC Monthly Gas Prices						
Month	QPC	NPC	KRGT	CIG	SoCAL	**Henry Hub**
Jan-97	$4.20	$4.20	$4.25	$4.18		
Feb-97	$2.45	$2.48	$2.53	$2 48		
Mar-97	$1.38	$1.39	$1.39	$1.40		
Apr-97	$1.42	$1.44	$1.44	$1.43		
May-97	$1.61	$1.64	$1.64	$1.63		
Jun-97	$1.45	$1.48	$1.47	$1.46		
Jul-97	$1.42	$1.44	$1.43	$1.44		
Aug-97	$1.38	$1.38	$1.37	$1.38		
Sep-97	$1.47	$1.48	$1.48	$1.47		
Oct-97	$2.10	$2.12	$2.09	$2.10		
Nov-97	$2.99	$3.00	$3.00	$2.99		
Dec-97	$1.93	$1.94	$1.93	$1.94		
1997 Average	**$1.98**	**$2.00**	**$1.99**	**$1.99**	**Prices not recorded**	
Jan-98	$2.04	$2.05	$2.04	$2.04		
Feb-98	$1.68	$1.69	$1.69	$1.70		
Mar-98	$1.86	$1.87	$1.88	$1.88		
Apr-98	$1.89	$1.90	$1.90	$1.90		
May-98	$1.97	$1.98	$1.97	$1.96		
Jun-98	$1.62	$1.64	$1.65	$1.64		
Jul-98	$1.61	$1.62	$1.62	$1.61		
Aug-98	$1.73	$1.73	$1.73	$1.73		
Sep-98	$1.53	$1.57	$1.59	$1.55		
Oct-98	$1.64	$1.65	$1.64	$1.65		
Nov-98	$1.91	$2 02	$2.01	$1.97		
Dec-98	$2.00	$2.00	$2.00	$1.96		
1998 Average	**$1.79**	**$1.81**	**$1.81**	**$1.80**	**Prices not recorded**	

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BAKER & McKENZIE

ATTORNEYS AT LAW

Europe Middle East

AMSTERDAM MADRID BAHRAIN MILAN BARCELONA MOSCOW BERLIN MUNICH BRUSSELS PARIS BUDAPEST PRAGUE CAIRO RIYADH DÜSSELDORF ROME FRANKFURT ST. PETERSBURG GENEVA STOCKHOLM KYIV WARSAW LONDON ZURICH

Asia Pacific

ALMATY BAKU BANGKOK BEIJING HANOI HO CHI MINH CITY HONG KONG HSINCHU MANILA MELBOURNE SINGAPORE SYDNEY TAIPEI TOKYO

815 CONNECTICUT AVENUE, N.W.
WASHINGTON, D.C. 20006-4078
TELEPHONE (202) 452-7000
FACSIMILE (202) 452-7074

North and South America

BOGOTA HOUSTON SAN DIEGO BRASILIA JUAREZ SAN FRANCISCO BUENOS AIRES MEXICO CITY SANTIAGO CALGARY MIAMI SAO PAULO CARACAS MONTERREY TIJUANA CHICAGO NEW YORK TORONTO DALLAS PALO ALTO VALENCIA GUADALAJARA RIO DE JANEIRO WASHINGTON, D.C.

Direct dial: (202) 452-7064
e-mail: john.a.cohen@bakernet.com

September 11, 2002

David Graeber
USA Power Partners, LLC
for Spring Canyon Energy, L.L.C.
10440 No. Central Expressway
No. 1400
Dallas, TX 75231

Re: Spring Canyon Energy, L.L.C., Docket No. EG02- -000

Dear Mr. Graeber:

Enclosed please find a stamped copy of the filing made in the above-referenced docket on Tuesday, September 10, 2002.

Please call either Mike Zimmer at (202) 452-7055 or me at the number above if there are any questions.

Thank you,

Sincerely,

John A. Cohen

John A. Cohen

JAC:jhm
Enclosures

cc: Michael J. Zimmer, Esq.

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FILED
OFFICE OF THE SECRETARY

UNITED STATES OF AMERICA
BEFORE THE

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FEDERAL ENERGY REGULATORY COMMISSION

FEDERAL ENERGY
REGULATORY COMMISSION

Spring Canyon Energy, L.L.C. **Docket No. EG02- - 000**

Application of Spring Canyon Energy, L.L.C.
For Determination of Exempt Wholesale Generator Status

Pursuant to Subchapter T, Part 365 of the Regulations of the Federal Energy Regulatory Commission (the "Commission"), 18 C.F.R. Part 365 (2002) implementing Section 32 of the Public Utility Holding Company Act of 1935, as amended (the "1935 Act"), 15 U.S.C. § 79 *et seq*., Spring Canyon Energy, L.L.C. (the "Applicant") hereby submits this Application requesting that the Commission determine that the Applicant is an exempt wholesale generator ("EWG"), as defined in the 1935 Act.

I. Principal Office of the Applicant

The principal office of the Applicant is set forth below:

Spring Canyon Energy, L.L.C.
10440 N. Central Expressway
No. 1400
Dallas, Texas 75231
Tel: (214) 520-8177
Fax: (214) 696-2422

II. Communications

All communications regarding this Application should be provided to:

Michael J. Zimmer, Esq.
Baker & McKenzie
815 Connecticut Avenue, N.W.
Washington, D.C. 20006-4078
Tel: (202) 452-7055
Fax: (202) 452-7074

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- and -

David Graeber
USA Power Partners, LLC
- For -
Spring Canyon Energy, L.L.C.
10440 N. Central Expressway
No. 1400
Dallas, Texas 75231
Tel: (214) 520-8177
Fax: (214) 696-2422

III. Description of the Applicant and Eligible Facility

The Applicant is a limited liability company formed under the laws of the State of Utah that will own and/or operate an approximately 430 MW natural gas-fired electric generating base load facility located near Mona, Utah that can produce up to 540 MW utilizing duct burners when necessary (the "Facility"). The output of the Facility will be sold on the wholesale power market to various wholesale customers under long-term contract and/or a spot market basis. The Facility will include step-up transformers, switchgear, and related transmission interconnection components necessary to connect the Facility to the grid so as to make sales of electric energy at wholesale.

IV. Basis of Eligibility for EWG Status

Pursuant to Section 365.3 of the Commission's Regulations, 18 C.F.R. § 365.3 (2002), the Applicant, by and through its legally authorized representative, states as follows:

1. The Applicant will be engaged directly, or indirectly through one or more affiliates as defined in Section 2(a)(11)(B) of the 1935 Act, and exclusively in the business of owning and/or operating all or part of one or more eligible facilities and selling electric energy at wholesale. Applicant may also engage in activities incidental to the sale of electric energy consistent with Commission precedent.

8. A notice of this Application, suitable for publication in the Federal Register, is attached as Appendix A to this request and is also contained on the enclosed 3.5 inch diskette.

9. The Applicant has caused copies of this Application to be served upon the Securities and Exchange Commission and upon the state commission of Utah, this agency being the only affected state commission as defined in Section 365.2(b)(3) of the Commission's Regulations.

V. Summary of Request

Based on the foregoing facts and representations, the Applicant satisfies the requirements for exempt wholesale generator status, and respectfully requests a determination by the Commission that it is an exempt wholesale generator.

Respectfully submitted,

Michael J. Zimmer

Michael J. Zimmer
John A. Cohen
Baker & McKenzie
815 Connecticut Avenue, N.W.
Washington, D.C. 20006-4078
(202) 452-7000

Attorneys for
Spring Canyon Energy, L.L.C.

Dated: September 10, 2002

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VERIFICATION OF APPLICATION

District of Columbia) ss:

The undersigned, being duly sworn, states that he is the Attorney for Spring Canyon Energy, L.L.C., the Applicant in the foregoing Application; that he is legally authorized to bind the Applicant; that he has read said Application and knows the contents thereof; and that all of the statements contained therein are true and correct to the best of his knowledge and belief.

Michael J. Zimmer
Attorney for Spring Canyon Energy, L.L.C.

Sworn and subscribed before me, a notary public, this 10th day of September 2002.

Wenona F. Brown
Notary Public, District of Columbia
My Commission Expires 10-14-2006

Notary Public

My commission expires 10-14-2006

.Appendix A

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Spring Canyon Energy, L.L.C.) Docket No. EG02- -000

NOTICE OF APPLICATION FOR COMMISSION DETERMINATION OF EXEMPT WHOLESALE GENERATOR STATUS

On September 10, 2002, Spring Canyon Energy, L.L.C. (the "Applicant") whose address is 10440 N. Central Expressway, No. 1400, Dallas, Texas 75231, filed with the Federal Energy Regulatory Commission an application for determination of exempt wholesale generator status pursuant to Part 365 of the Commission's regulations.

The Applicant states that it will be engaged directly or indirectly and exclusively in the business of owning and/or operating a 430 MW (up to 540 MW with duct burners) electric generating facility located near Mona, Utah and selling electric energy at wholesale. The Applicant requests a determination that the Applicant is an exempt wholesale generator under Section 32(a)(1) of the Public Utility Holding Company Act of 1935.

Any person desiring to be heard concerning the application for exempt wholesale generator status should file a motion to intervene or comments with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure. The Commission will limit its consideration of comments to those that concern the adequacy or accuracy of the application. All such motions and comments should be filed on or before __________ and must be served on the Applicant. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Magalie R. Salas
Secretary

Tab 5

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JBB
FEB 11 2002
Utah Div. Of Corp. & Comm. Code

ARTICLES OF ORGANIZATION
OF
SPRING CANYON ENERGY, LLC

The undersigned, being natural persons eighteen (18) years of age or more and desiring to form a limited liability company under the laws of the state of Utah, do hereby sign, verify, and deliver to the Division of Corporations and Commercial Code of the state of Utah these Articles of Organization for the above-named company (hereinafter referred to as the "Company"):

ARTICLE I
NAME

The name of the Company shall be: Spring Canyon Energy, LLC

02-11-02P02:13 RCVD

ARTICLE II
PERIOD OF DURATION

The Company shall continue in existence until December 31, 2090, unless sooner dissolved according to law or the operating agreement.

ARTICLE III
PURPOSES AND POWERS

The Company is organized for the following purpose or purposes:

To engage in the acquisition and ownership of interests in real and personal property; and to engage in any lawful act or activity for which a limited liability company may be organized under the laws of the state of Utah and to exercise all powers permitted thereby.

ARTICLE IV
LIMITATION ON POWERS AND AUTHORITY OF MANAGER

The manager(s) of the Company shall not have the right or power to do any of the following without the consent of members of the Company holding in the aggregate 67% or more of all of the outstanding membership units entitled to vote:

Date: 02/12/2002
Receipt Number: 506959
Amount Paid: $50.00

(a) Do any act which would make it impossible to carry on the ordinary business of the Company;

(b) Make a substantial change in the authorized business of the Company;

(c) Confess a judgment against the Company;

(d) Use the Company name, credit or assets for other than Company purposes;

(e) Do any act in contravention of the operating agreement of the Company;

5069048-0160

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(f) Amend the operating agreement;

(g) Commingle the funds of the Company with the funds of any other person or entity;

(h) Submit any dispute involving the Company to binding arbitration;

(i) Execute or deliver any assignment for the benefit of the creditors of the Company;

(j) Cause the Company to borrow any sums for which the Members have recourse liability;

(k) Transact any business on behalf of the Company in any jurisdiction, unless the Members would not, as a result thereof, become managers and have any liability greater than that provided in the operating agreement;

(l) Cause the Company to borrow or incur any indebtedness, in the aggregate, in excess of $10,000;

(m) Obligate the Company to make a capital expenditure in excess of $50,000;

(n) Cause the Company to merge with or into another entity or to convert into another type of entity;

(o) Dispose of substantially all of the assets or the goodwill of any business of the Company; and

(p) Admit a person or entity as a member of the company, except as provided in the operating agreement.

ARTICLE V
TRANSACTIONS WITH MEMBERS AND MANAGERS

No contract or other transaction between the Company and any firm or corporation shall be affected by the fact that a member or manager of the Company has an interest in, or is a director or officer of, such other firm or corporation. Any member or manager, individually or with others, may be a party to, or may have an interest in, any transaction of the Company or any transaction in which the Company is a party or has an interest. Each person who is now or may become a member or manager of the Company is hereby relieved from liability that he might otherwise incur in the event such officer or director contracts with the Company, individually or in behalf of another corporation or entity, in which he may have an interest; provided, that such member or manager acts in good faith.

ARTICLE VI
LIMITATION ON LIABILITY

A manager of the Company shall have no personal liability to the Company or its members for monetary damages for breach of fiduciary duty, except (i) for any breach of a manager's duty of loyalty to the Company or its members, (ii) for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law, or (iii) for any transaction from which a manager derived an improper personal benefit.

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ARTICLE VII
INDEMNIFICATION OF MANAGERS, MEMBERS, AND OTHERS

The Company shall indemnify each manager, employee, or agent of the Company and their respective heirs, administrators, and executors against all liabilities and expenses reasonably incurred in connection with any action, suit, or proceeding to which he may be made a party by reason of his being or having been a manager, employee, or agent of the Company, to the full extent permitted by the laws of the state of Utah now existing or as such laws may hereafter be amended.

The Company shall indemnify any person who was or is a party or is threatened to be made a party to any threatened, pending, or completed action or suit by or in the right of the Company to procure a judgment in its favor by reason of the fact that he is or was a manager, employee, or agent of the Company, or is or was serving at the request of the Company as a manager, director, employee, or agent of another company, corporation, partnership, joint venture, trust, or other enterprise, against expenses, including attorneys' fees, judgments, fines, and amounts paid in settlement, actually and reasonably incurred by him in connection with the defense or settlement of the action, suit, or proceeding, if he acted in good faith and in a manner he reasonably believed to be in or not opposed to the best interests of the Company, except that no indemnification shall be made in respect of any claim, issue, or matter as to which such a person shall have been adjudged to be liable to the Company, unless and only to the extent that the court in which the action or suit was brought shall determine on application that, despite the adjudication of liability but in view of all circumstances of the case, the person is fairly and reasonably entitled to indemnity for such expenses as the court deems proper.

ARTICLE VIII
AMENDMENTS

The Company reserves the right to amend, alter, change, or repeal all or any portion of the provisions contained in its Articles of Organization from time to time in accordance with the laws of the state of Utah, and all rights conferred on members herein are granted subject to this reservation.

ARTICLE IX
ADOPTION OR AMENDMENT OF OPERATING AGREEMENT

The initial operating agreement of the Company shall be adopted by its members. The power to alter, amend, or repeal the operating agreement or adopt a new operating agreement shall be vested in the members. The operating agreement may contain any provisions for the regulation and management of the affairs of the Company not inconsistent with the Utah Revised Limited Liability Company Act, as now existing or as hereafter amended, or these Articles of Organization.

ARTICLE X
RESTRICTION ON TRANSFER OF OWNERSHIP

No member shall sell, assign, hypothecate, or dispose of his interest or any part thereof in the Company without the written consent of the others except as may be set forth in the operating agreement.

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ARTICLE XI
REGISTERED OFFICE AND REGISTERED AGENT

The address of the Company's registered office in the state of Utah is 50 West Broadway, Suite 800, Salt Lake City, Utah 84101. The name of its initial registered agent at such registered office is CT Corporation. Either the registered office or the registered agent may be changed in the manner provided for by law. In the event that the registered agent of the Company resigns, the agent's authority has been revoked, or the registered agent cannot be found or served with the exercise of reasonable diligence and a new registered agent has not been appointed by the Company, the director of the Division of Corporations and Commercial Code of the state of Utah shall be deemed appointed the agent of the Company for the purpose of service of process.

ARTICLE XII
DESIGNATED OFFICE

The address of the Company's designated office in the state of Utah is CT Corporation, 50 West Broadway, Suite 800, Salt Lake City, Utah 84101.

ARTICLE XIII
INITIAL MANAGERS

The Company shall be managed by a manager or managers. The governing body of the Company shall be known as the manager, and the number of managers of the Company shall be fixed by the operating agreement of the Company. The name and street address of the initial managers to serve as provided in the operating agreement and until his or her successors are elected and shall qualify are as follows:

Name	Address
F. David Graeber	10440 North Central Expressway Suite 1400 Dallas, TX 75231
Lois Banasiewicz	P. O. Box 774000-359 31 585 Runaway Place Steamboat Springs, CO 80477

The undersigned, being the managers of the Company hereinbefore named, makes and files these Articles of Organization, hereby declaring that the facts herein are true.

DATED this 11 day of February, 2002.

F. David Graeber

Lois Banasiewicz

CT Corporation hereby accepts appointment as registered agent for Spring Canyon Energy, LLC, as named in the foregoing Articles of Organization.

CT CORPORATION

By: [signature]

Title: Ms Deanette Widmer
Special Assistant
Secretary

DEPARTMENT OF THE TREASURY
INTERNAL REVENUE SERVICE
OGDEN UT 84201

DATE OF THIS NOTICE: 02-21-2002
NUMBER OF THIS NOTICE: CP 575 B
EMPLOYER IDENTIFICATION NUMBER: 68-0489498
FORM: SS-4
0533626984 B

SPRING CANYON ENERGY LLC
% LOIS BANASIEWICZ
PO BOX 774000 359
STEAMBOAT SPRINGS CO 80477

FOR ASSISTANCE CALL US AT:
1-800-829-1040

OR WRITE TO THE ADDRESS SHOWN AT THE TOP LEFT.

IF YOU WRITE, ATTACH THE STUB OF THIS NOTICE.

WE ASSIGNED YOU AN EMPLOYER IDENTIFICATION NUMBER (EIN)

Thank you for your Form SS-4, Application for Employer Identification Number (EIN). We assigned you EIN 68-0489498. This EIN will identify your business account, tax returns, and documents, even if you have no employees. Please keep this notice in your permanent records.

Use your complete name and EIN shown above on all federal tax forms, payments and related correspondence. If you use any variation in your name or EIN, it may cause a delay in processing and incorrect information in your account. It also could cause you to be assigned more than one EIN.

Based on the information shown on your Form SS-4, you must file the following forms(s) by the date we show.

Form 1065	04/15/2003

Your assigned tax classification is based on information obtained from your Form SS-4. It is not a legal determination of your tax classification and is not binding on the IRS. If you want a determination on your tax classification, you may seek a private letter ruling from the IRS under the procedures set forth in Rev. Proc. 98-01, 1998-1 I.R.B. 7 (or the superceding revenue procedure for the year at issue).

If you need help in determining what your tax year is, you can get Publication 538, Accounting Periods and Methods, at your local IRS office.

If you have questions about the forms shown or the date they are due, you may call us at 1-800-829-1040 or write to us at the address shown above.

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STATE OF UTAH DEPARTMENT OF COMMERCE REGISTRATION SPRING CANYON ENERGY, LLC EFFECTIVE 02/11/2002 EXPIRATION *RENEWAL	REFERENCE NUMBER(S), CLASSIFICATION(S) & DETAIL(S) LLC - Domestic 5069048-0160

C T CORPORATION SYSTEM
SPRING CANYON ENERGY, LLC
50 W BROADWAY 8TH FLOOR
SALT LAKE CITY UT 84101

STATE OF UTAH
DEPARTMENT OF COMMERCE
DIVISION OF CORPORATIONS & COMMERCIAL CODE
REGISTRATION

EFFECTIVE DATE: 02/11/2002

EXPIRATION DATE: *RENEWAL

ISSUED TO: SPRING CANYON ENERGY, LLC

THE GREAT SEAL OF THE STATE OF UTAH 1896

REFERENCE NUMBER(S), CLASSIFICATION(S) & DETAIL(S)

5069048-0160 LLC - Domestic

*RENEWAL
You will need to renew your registration each anniversary date of the effective date.
Exceptions: DBAs and Business Trusts renew every three (3) years from the effective date.

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CONFIDENTIAL

USA Power Partners LLC

Supplemental Due Diligence Information
To
Preliminary Offering Memorandum

Volume 3

Spring Canyon Energy LLC

450 Mw Natural Gas Fired,
Combined-Cycle Power Facility,
With Duct-Firing Capability for an
Additional 80 MW

Located in Juab County, Utah
With interconnection to the Western US RTO
Via the Mona (PacifiCorp) Substation

January 2003

Supplemental Due Diligence Information
To
Preliminary Offering Memorandum
Volume 3

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Spring Canyon Energy, LLC
January 2003

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Spring Canyon Energy Strategic Power Market Assessment

In June 2002, Spring Canyon Energy, LLC contracted with Navigant Consulting to conduct a power market assessment for possible delivery of power from its Mona substation site in central Utah to areas in the western United States. The following summarizes the Navigant Study, which is included in the Spring Canyon Energy Preliminary Offering Memorandum, dated August 2002.

Navigant concluded that the Spring Canyon Energy project will be able to access power markets in a minimum of seven western states. Despite the potential and real transmission issues that exist in the Western Electricity Coordinating Council (WECC), there are multiple opportunities for the Spring Canyon Energy project to deliver competitively priced power to specific market areas with a need for new resources. There are two primary target markets, Utah and Southern California, and a secondary market, Northern Nevada. A third opportunity would involve a displacement arrangement with PacifiCorp and one or more of its trading partners. The Navigant work did not include an analysis of the Colorado or Idaho markets since pricing in these markets has been lower than others in the region; however, these markets should be considered to be a viable potential backup to the primary targets.

Utah Market Area

The Utah market area is the prime target for the output of the Spring Canyon Energy project. Whether the output is ultimately used for sale to the Utah market area electric utilities or as displacement for transactions with entities located outside of the Utah market area, the Spring Canyon Energy project's prime market focus is Utah.

Within the Utah market area there are four entities that provide viable opportunities PacifiCorp, UAMPS, UMPA and Deseret G&T Obviously, due to its size and the ownership of transmission facilities, the largest opportunity is with PacifiCorp

Based upon existing resources in the Utah market area and the expected load growth for the region, PacifiCorp is seeking additional capacity in the Utah market area and the Spring Canyon Energy project will provide fuel diversity and operational flexibility. Opportunities with PacifiCorp include diversity programs, base load resource, displacement opportunities, operational flexibility, and access to newer technology with a superior heat rate, lower operation and maintenance costs, and significantly reduced emissions.

Southern California Market Area

The Southern California market area provides the other prime market for the Spring Canyon Energy project. Via the Intermountain DC transmission line (which begins at the Mona Switching Station and ends near Los Angeles) the Spring Canyon Energy project can serve the deep Southern California market area. The Southern California Public Power Agency (SCPPA) owns the Intermountain DC transmission line and the uncommitted capacity on this system could be utilized to move the entire output from Spring Canyon to the Southern California market area. The members of SCPPA include Los Angeles, Anaheim, Riverside, Pasadena, Burbank and Glendale, which together represent over 7,500 Mw of Load. The members of SCPPA do not have the same credit issues plaguing many of California's investor and utilities.

Northern Nevada Market Area

The Northern Nevada market area is a very viable market due to its deficiency of in-area generation and forecasted load growth. However, due to the current poor financial condition of Nevada's investor owned utility, Sierra Pacific, a long-term commitment from these entities will not be creditworthy until the Nevada Utility Commission resolves the rate and recovery issues in a definitive way

PacifiCorp Integrated Resource Plan - 2003

In October 2002, PacifiCorp issued its draft Integrated Resource Plan. The final plan will be submitted for commission approval on January 24, 2003 The final version of the plan, which will include an additional focus on renewables, will not alter its conclusion regarding a new generation facility located at the Mona Switching Station. The following summarizes the PacifiCorp Integrated Resource Plan:

> "The purpose of the IRP is to provide the framework for the prudent future actions required to ensure that PacifiCorp continues to provide reliable and least-cost electric service to its customers. The IRP reveals that PacifiCorp expects its obligation to provide electricity to its customers will continue to grow while at the same time its existing resources will diminish significantly. Load growth, load shape growth, asset retirement and contract expirations cause the gap between demand and supply to grow over time Measures must be taken to close the gap, and the IRP proposes several specific actions. Not taking these actions will expose PacifiCorp to unacceptable levels of cost, reliability and market risk."

The IRP proposes a significant procurement of new resources. The strategy outlined in the IRP includes the addition of 4,000 Mw of new capacity in the next ten years The least cost, risk-adjusted approach proposed includes.

- 450 Mw of demand side management,
- 1,146 Mw of renewables,
- 2,200 Mw of base-load capacity,
- 1,000 Mw of peaking capacity, and
- 300-700 Mw of shaped resource contracts

PacifiCorp currently serves 1 5 million retail customers in six western states Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp forecasts load on its system to grow by 2 2% on the average At the same time, the resources available to PacifiCorp to serve this demand will diminish over time as contracts expire, hydro facilities are subjected to relicensing conditions and thermal plants comply with more stringent emission requirements. This creates an imbalance, which is referred to as the "gap." In 2004, the gap is estimated to be 1,275 Mw, which grows to over 4,000 Mw by 2014.

IRP Recommended Actions

Like most integrated resource plans, the IRP analyzes many different resource scenarios and draws a conclusion that there are three scenarios that will best meet the goals associated with the IRP. Appendix D, which begins on page 189 of the IRP, describes each of the scenarios. For each scenario, the specific resources and their timing are described. The three selected scenarios are 1) Gas/Coal I, page 189, 2) Renewables, page 190, and 3) Coal/Gas III, page 197. Each Scenario includes a gas-fired facility at the Mona Switching Station ranging from 480 Mw to 680 Mw scheduled to come on line as early as 2007. Also each scenario includes short-term purchases of 500 Mw terminating when the Mona facility comes on line. Each scenario also includes a 500 Mw gas-fired facility at Gatsby located in downtown Salt Lake City. Both of the Gas/Coal I and Coal/Gas III scenarios includes a new 575 Mw unit at the Hunter Station. The renewable scenario replaces the coal resource at Hunter with additional wind resource purchases. The IRP states that for each resource, PacifiCorp will compare the economic benefit of issuing a long-term contract or building the generating asset themselves.

Strategy with PacifiCorp

The IRP concludes that there will be a gas-fired facility at Mona in 2007. The timing (i.e. 2007) of the Mona facility is based on the assumption that PacifiCorp will develop and build the facility, which will require 48 months. In the meantime, PacifiCorp will make short-term purchases. Since the Spring Canyon Energy project has received all of its permits and approvals required to commence construction, it is possible for the Spring Canyon Energy project to begin operation two years sooner (i.e. 2005 verses 2007). The value that Spring Canyon Energy provides to PacifiCorp is that the price of energy from Spring Canyon Energy, utilizing competitively priced Rocky Mountain natural gas, is significantly lower than that which would be paid from short-term contracts

Conservative estimates of this saving are between \$20-\$40 million per year. This provides a huge incentive for PacifiCorp to either purchase the Spring Canyon Energy project or to issue a long-term power contract to Spring Canyon Energy. Spring Canyon Energy, LLC is currently discussing both possibilities with high-level representatives from PacifiCorp. It is the preference of Spring Canyon Energy to secure a long-term power contract and, with an involvement from Energy Investors Fund Group ("EIF"); Spring Canyon Energy will be in a position to terminate its discussions regarding the sale of the facility to PacifiCorp.

In order for PacifiCorp to move forward with the PPA discussions, PacifiCorp must receive an "acknowledgment of approval" from the public service commissions in the various states, which they serve. PacifiCorp representatives estimate that this acknowledgement could be obtained before the end of March 2003, but could take longer. Discussions and perhaps document drafting may occur prior to the acknowledgement, however, PacifiCorp will not finalize or submit the PPA for commission approval without commission acknowledgement of its IRP.

The timing of the PacifiCorp commission's acknowledgement provides an opportunity for Spring Canyon Energy to secure addition parties interested in purchasing the output of Spring Canyon Energy. In order to receive the best pricing from PacifiCorp, it is important that they are convinced that they are not the only viable purchaser.

Recent studies conducted by Henwood Consulting conclude that several of the California purchasers will again be short on energy supplies. This includes Sempra and SCPPA, which are the two most creditworthy purchasers in California. While a contract with PacifiCorp is the highest priority, selling and transporting power to either SCPPA or Sempra remains extremely viable. The Spring Canyon Energy interconnect is with the PacifiCorp system, however, the Mona Switching Station is owned jointly by SCPPA, Deseret G&T, and PacifiCorp. The owners have declared Mona to be a "zero cost bus," therefore; Spring Canyon Energy can interconnect with PacifiCorp and sell power to SCPPA without an additional wheeling charge The agreements between Sempra and

SCPPA would allow Sempra to purchase power from Spring Canyon Energy and move the power on SCPPA's transmission system.

CONCLUSION

In conclusion, Spring Canyon Energy LLC will likely secure a long-term power contract from PacifiCorp, however, other creditworthy entities also have resource needs and these entities may ultimately be willing to pay prices higher than PacifiCorp.

Utah!
Where ideas connect
Department of Environmental Quality
Division of Air Quality

Michael O Leavitt
Governor
Dianne R. Nielson, Ph D
Executive Director
Richard W Sprott
Director

150 North 1950 West
P O Box 144820
Salt Lake City, Utah 84114-4820
(801) 536-4099 Fax
(801) 536-4414 T D D
www deq utah gov

DAQE-AN2627001-02

November 27, 2002

Ms. Lois Banasiewicz
Principal
Spring Canyon Energy, LLC.
P. O. Box 774000-359
Steamboat Springs, Colorado 80477

Dear Ms. Banasiewicz:

Re: Approval Order: Power Generating Facility With One Natural Gas Fired Combined Cycle Turbine Generator Set With Duct Burner, Juab County - CDS SM; ATT; NSPS, HAPs
Project Code: N2627001-02

The attached document is the Approval Order for the above-referenced project.

Future correspondence on this Approval Order should include the engineer's name as well as the DAQE number as shown on the upper right-hand corner of this letter. Please direct any technical questions you may have on this project to Ms. Milka M. Radulovic. She may be reached at (801) 536-4232.

Sincerely,

Richard W Sprott, Executive Secretary
Utah Air Quality Board

RWS RR MR re

cc: Central Utah Public Health Department
Mike Owens, EPA Region VIII

P1100

10039

STATE OF UTAH

Department of Environmental Quality

Division of Air Quality

APPROVAL ORDER: POWER GENERATING FACILITY WITH ONE NATURAL GAS FIRED COMBINED CYCLE TURBINE GENERATOR SET WITH DUCT BURNER

Prepared By: Milka M. Radulovic, Engineer
(801) 536-4232
Email:milkar@utah.gov

APPROVAL ORDER NUMBER

DAQE-AN2627001-02

Date: November 27, 2002

Spring Canyon Energy, LLC.
Source Contact
Lois Banasiewicz
(970) 871-6223

Richard W. Sprott
Executive Secretary
Utah Air Quality Board

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Abstract

Spring Canyon Energy, LLC (SCE) is proposing to construct, own, and operate a new power generating facility in the Juab Valley, Juab County, just west of the Mona Reservoir. The facility will consist of one natural gas turbine generator set in a combined cycle configuration [with one heat recovery steam generator (HRSG) and one steam turbine-generator]. In addition, there will be one diesel fired emergency generator, one diesel-fired emergency fire pump, small diesel fuel storage tanks, an air- cooled condenser (to condense spent steam back into water for recycling to the HRSG), and aqueous ammonia storage and handling equipment. The HRSG duct burners will be fired with natural gas to augment waste heat from the gas turbine exhaust. The power facility will operate with a combined net maximum generating capacity of about 280 MW at 0^0F. It is anticipated that the gas turbine will be purchased from General Electric with Dry Lo-NO_x combustion system. NO_x emissions from the gas turbine will be controlled to 2 ppmvd at 15% O_2 reference (by selective catalytic reduction system), CO to 4 ppmvd at 15% O_2 reference (9 ppmvd with duct firing), and ammonia slippage to 10 ppm. The turbine will not be designed to operate in a simple-cycle mode (i.e., bypassing the HRSG unit). Raw materials used at the Spring Canyon plant in addition to natural gas and air, are water (to generate the steam) and ammonia for the selective catalytic (NO_x) reduction process. Use of the dry type air-cooled condenser greatly reduces the plant's water usage.

Juab County is an attainment area of the National Ambient Air Quality Standards (NAAQS) for all pollutants.

New Source Performance Standards (NSPS) 40 CFR 60, Subpart GG (Standards of Performance for Stationary Gas Turbines) applies to the proposed turbine. NSPS 40 CFR 60, Subpart Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978) applies to the duct burners.

Estimated annual emissions from the entire facility, in tons per year, will be as follows: 66,4 of NO_x, 97.5 of CO, 5.3 of SO_2, 70.9 of PM_{10}, 67.12 of VOC, and 5.7 tons of hazardous air pollutants (mainly formaldehyde).

Since the emissions have increased above modeling threshold levels for the NO_x, CO, PM_{10}, and formaldehyde, an air quality modeling assessment consistent with UAC R307-410-2 was performed. The US EPA and the State accepted Industrial Source Complex Short Term - Version 3 (ISCST3) model was used by the Applicant to predict air pollutant concentrations under a simple/complex terrain/wake effect situation. The modeling analysis indicated, and the State verified, that there would be no violations of NAAQS and Prevention of Significant Deterioration increments consumption for the proposed project.

The project has been evaluated and found to be consistent with the requirements of the Utah Administrative Code Rule 307 (UAC R307). A public comment period was held in accordance with UAC R307-401-4 and comments were received. The comments were evaluated and no comment was found to be adverse to the proposed AO. This air quality Approval Order (AO) authorizes the project with the following conditions, and failure to comply with any of the conditions may constitute a violation of this order.

General Conditions:

1. This Approval Order (AO) applies to the following company:

   Corporate Office Location
   USA Power Partners, LLC
   Spring Canyon Energy, LLC
   PO Box 774000-359
   Steamboat Springs, Colorado 80477
   Phone Number (970) 871-6223
   Fax Number (970) 871-6234

   The equipment listed in this AO shall be operated at the following location:

   From Salt Lake City take I-15 south approximately 77 miles to Hwy 54. Take exit and proceed west through Mona. Go ½ mile north on Goshen Canyon Road; Plant site is ½ mile to the west.
   Juab County

   Universal Transverse Mercator (UTM) Coordinate System: UTM Datum NAD27
   4,410.042 kilometers Northing, 422.81 kilometers Easting, Zone 12

2. All definitions, terms, abbreviations, and references used in this AO conform to those used in the Utah Administrative Code (UAC) Rule 307 (R307) and Title 40 of the Code of Federal Regulations (40 CFR). Unless noted otherwise, references cited in these AO conditions refer to those rules.

3. The limits set forth in this AO shall not be exceeded without prior approval in accordance with R307-401.

4. Modifications to the equipment or processes approved by this AO that could affect the emissions covered by this AO must be reviewed and approved in accordance with R307-401-1.

5. All records referenced in this AO or in applicable NSPS standards, which are required to be kept by the owner/operator, shall be made available to the Executive Secretary or Executive Secretary's representative upon request, and the records shall include the two-year period prior to the date of the request. Records shall be kept for the following minimum periods:

A.	Emission inventories	Five years from the due date of each emission statement or until the next inventory is due, whichever is longer.
B	All other records	Two years

6. Spring Canyon Energy, LLC shall install and operate one natural gas fueled combined cycle turbine generator set with duct burner and ambient air inlet chiller with maximum combined rating of approximately 280 MW, one diesel fired emergency generator rated at 700 bhp, one diesel fired fire pump rated at 250 bhp, and miscellaneous small diesel

fuel storage tanks (each with storage capacity of less that 10,000 gallons) at the Spring Canyon Energy power generating facility in accordance with the terms and conditions of this AO, which was written pursuant to Spring Canyon Energy, LLC's Notice of Intent submitted to the Division of Air Quality (DAQ) on August 13, 2002 and additional information submitted to the DAQ on August 15, 2002, August 29, 2002, September 18, 2002, September 26, 2002, and October 10, 2002.

7. The approved installations shall consist of the following equipment or equivalent*.

A. One (1) General Electric Frame 7-FA (PG7241FA)* gas turbine, with one (1) HRSG, and one (1) steam turbine generator set

The gas turbine is provided with ambient inlet air chiller coils. The Heat Recovery Steam Generator (HRSG) is equipped with a Selective Catalytic Reduction System for abatement of NO_x emissions from the Duct Burner and the Gas Turbine. Continuous Emission Monitoring System (CEMS) for the HRSG stack is provided for monitoring emissions from the gas turbine and duct burners. The power generating facility has the following characteristics:

Maximum plant site rated output at 100% Load,
0^0F, 12.19 psia and 25% relative humidity: 280 MW
Heat input at the baseload, ISO (59^{0}F, site elevation): 1,472.9 x Btu/hr (HHV)***
Maximum gas turbine firing rate: 1,621.5 x 10^6 Btu/scf (HHV)

B. One (1) Coen Power Plus* duct burner state of the art, low emission technology Coen Power Plus* (subject to 40 CFR 60, Subpart Da)
Maximum firing rate: 520 x 10^6 Btu/hr (HHV)

C. One (1) Diesel Fired Emergency Generator rated at 700 bhp

D. One (1) Diesel Fired Emergency Fire Pump rated at 250 bhp

E. Miscellaneous diesel fuel storage tanks, each individual tank storage capacity is less than 10,000 gallons

F. One (1) Dry type air-cooled condenser **

* Equivalency shall be determined by the Executive Secretary.

** This equipment is listed for informational purposes only There are no emissions from this equipment

***Fuel Higher Heating Value

8 Spring Canyon Energy, LLC shall notify the Executive Secretary in writing when the installation of the equipment listed in Condition #7 has been completed and is operational, as an initial compliance inspection is required To insure proper credit when notifying the Executive Secretary, send your correspondence to the Executive Secretary, attn Compliance Section

If construction and/or installation have not been completed within eighteen months from the date of this AO, the Executive Secretary shall be notified in writing on the status of the construction and/or installation. At that time, the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation and may revoke the AO in accordance with R307-401-11.

Limitations

9. Visible emissions from the following emission points shall not exceed the following values:
   A. Natural gas combustion exhaust stacks - 10% opacity
   B. All other points - 20% opacity

   Opacity observations of emissions from stationary sources shall be conducted according to 40 CFR 60, Appendix A, Method 9.

10. The following limits shall apply:

    A. Gas Turbine, Stack Height - no less than 295.27 feet (90 meters) as measured from the ground
    B. Gas Turbine, Stack Exit Diameter - not greater than 17 feet

11. Combined source wide CO emissions shall be no greater than 97.5 tons per rolling 12-month period.

    Compliance to the above emission limitation shall be determined as follows:

    CO from the gas turbine and the duct burner shall be obtained from CEMS recorded data (conversion from ppmvd into pounds shall be done using the procedure in the EPA reference Method 19 or other procedure approved by the Executive Secretary).
    CO from the emergency generators shall be obtained by multiplying the engine rating, recorded hours of operation and emission factors from the Vendor data if available or EPA' s Compilation of Air Pollutant Emission Factors, AP-42

    To determine compliance with a rolling 12-month total the owner/operator shall calculate a new 12-month total by the twentieth day of each month using data from the previous 12 months. Records of hours of operation and emissions rates shall be kept for all periods when the plant is in operation. For emergency generator and the emergency fire pump hours of operation shall be determined by supervisor monitoring and maintaining of an operations log. The records of consumption/production shall be kept on a daily basis.

12. Combined emission rate of PM_{10}+ NO_x + SO_2 shall not be greater than of 780 72 lb per any rolling 24-hour average at the stack exhaust (turbine and the duct burner) Compliance to the above emission limitation shall be determined as follows

    NO_x from the gas turbine and the duct burner shall be obtained from CEMS recorded data (conversion from ppmvd into pounds shall be done using the procedure in EPA reference Method 19 or other procedure approved by the Executive Secretary)

PM_{10} from the gas turbine and the duct burner shall be from the latest emission test recorded data
SO_2 from the gas turbine and the duct burner shall be from the latest emission test or if testing is not required by the other alternative method as approved by the Executive Secretary or Administrator

To determine compliance with rolling 24-hour total the owner/operator shall calculate average hourly rate and sum them over 24-hour period New 24-hour total shall be calculated by the noon of the next day Records of hours of operation and emissions rates shall be kept for all periods when the plant is in operation

13 Emergency generators shall be used for electricity producing operation only during the periods when electric power from the public utilities is interrupted, or for regular maintenance of the generators Records documenting generator usage and fire pump usage shall be kept in a log and they shall show the date the generator was used, the duration in hours of the generator usage, and the reason for each generator usage

Fuels

14 The owner/operator shall use only natural gas, as fuel in the gas turbine and duct burner; fuel oil #2 or better in the emergency generator and the fire pump

15. The sulfur content of any fuel oil or diesel burned shall not exceed.

0 5 percent by weight for diesel fuels

The sulfur content shall be determined by ASTM Method D-4294-89 or approved equivalent Certification of other fuels shall be either by USA Power, LLC's own testing or test reports from the fuel marketer

Federal Limitations and Requirements

16. In addition to the requirements of this AO, all applicable provisions of 40 CFR 60, New Source Performance Standards (NSPS) Subpart A, 40 CFR 60 1 to 60 18, Subpart GG, 40 CFR 60 330 to 60 334 (Standards of Performance for Stationary Gas Turbines) and Subpart Da, 40 CFR 60 40a to 60 49a (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978) apply to this installation

17. In addition to the requirements of this AO, all applicable provisions of 40 CFR Part 72, 73, 75, 76, 77, and 78 Federal regulations for the Acid Rain Program under Clean Air Act Title IV apply to this installation

Limitations and Tests Procedures

18 Emissions to the atmosphere from the indicated emission points shall not exceed the following rates and concentrations

Source: Turbine GE Frame 7-FA (PG7241FA)) and Duct Burner Exhaust Stack

Pollutant	ppmvd* (15% O_2 dry) (30-day rolling average)	ppmvd** (15% O_2 dry) (30-day rolling average)	ppmvd (15% O_2 dry)
NO_x	2	2	***
CO	4	9	NA

*Total emissions concentration from the gas turbine under steady state operation not including startups and shutdowns
**Combined emissions concentration from the gas turbine and the duct burner under steady state operation not including startups and shutdowns
*** Emissions from the gas turbine (in accordance with 40 CFR 60 Subpart GG requirements)

19. Emissions testing, and compliance monitoring to the atmosphere from the duct burner shall be performed in accordance with all applicable provisions of 40 CFR 60, New Source Performance Standards (NSPS) Subpart A and Subpart Da, 40 CFR 60.40a to 60.49a (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978) apply to this installation.

20. Stack testing to show compliance with the emission limitations stated in the above condition shall be performed as specified below

A.

Emissions Point	Pollutant	Testing Status	Test Frequency
Gas turbine only	NO_x	*, **	CEMs
	CO	*	CEMs
Gas turbine & duct burner	NO_x	*	CEMs
	CO	*	CEMs
Gas turbine	PM_{10}	***	NA
Gas turbine & duct burner	PM_{10}	****	NA
Duct Burner	*****		

*Initial compliance shall be demonstrated with Relative Accuracy Testing Audit.
**Initial compliance testing for NO_x for the gas turbine shall be performed in accordance with the 40 CFR 60 Subpart GG.
***, ****Initial test to establish emission rate value for the calculations in the Condition #12
***** Initial compliance testing for the Duct Burner shall be performed in accordance with the 40 CFR 60 Subpart Da.

Initial compliance testing shall be performed within 60 days after achieving the maximum production rate at which the affected facility will be operated and in no case later than 180 days after the start up of a new emission source.

B. Notification

The Executive Secretary shall be notified at least 30 days prior to conducting any required emission testing. A source test protocol shall be submitted to DAQ when the testing notification is submitted to the Executive Secretary.

The source test protocol shall be approved by the Executive Secretary prior to performing the test(s). The source test protocol shall outline the proposed test methodologies, stack to be tested, procedures to be used. A pretest conference shall be held, if directed by the Executive Secretary.

C. Sample Location

The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other methods as approved by the Executive Secretary. An Occupational Safety and Health Administration (OSHA) or Mine Safety and Health Administration (MSHA) approved access shall be provided to the test location.

D. Volumetric Flow Rate

40 CFR 60, Appendix A, Method 2 or other testing methods approved by the Executive Secretary.

E. PM_{10}

For stacks in which no liquid drops are present, the following methods shall be used: 40 CFR 51, Appendix M, Methods 201, 201a, 202 or other testing methods approved by the Executive Secretary. The back half condensibles shall also be tested using the method specified by the Executive Secretary. All particulate captured shall be considered PM_{10}.

For stacks in which liquid drops are present, methods to eliminate the liquid drops should be explored. If no reasonable method to eliminate the drops exists, then the following methods shall be used: 40 CFR 60, Appendix A, Method 5, 5a, 5d, or 5e as appropriate, or other testing methods approved by the Executive Secretary. The back half condensibles shall also be tested using the method specified by the Executive Secretary. The portion of the front half of the catch considered PM_{10} shall be based on information in Appendix B of the fifth edition of the EPA document, AP-42, or other data acceptable to the Executive Secretary.

The back half condensibles shall not be used for compliance demonstration but shall be used for inventory purposes

F. Calculations

To determine mass emission rates (lb/hr, etc) the pollutant concentration as determined by the appropriate methods above shall be multiplied by the

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volumetric flow rate and any necessary conversion factors determined by the Executive Secretary, to give the results in the specified units of the emission limitation.

G. New Source Operation

For a new source/emission point, the production rate during all compliance testing shall be no less than 90% of the production rate listed in this AO. If the maximum AO allowable production rate has not been achieved at the time of the test, the following procedure shall be followed:

1. Testing shall be at no less than 90% of the production rate achieved to date.

2. If the test is passed, the new maximum allowable production rate shall be 110% of the tested achieved rate, but not more than the maximum allowable production rate. This new allowable maximum production rate shall remain in effect until successfully tested at a higher rate.

3. The owner/operator shall request a higher production rate when necessary. Testing at no less than 90% of the higher rate shall be conducted. A new maximum production rate (110% of the new rate) will then be allowed if the test is successful. This process may be repeated until the maximum AO production rate is achieved.

H. Existing Source Operation

For an existing source/emission point, the production rate during all compliance testing shall be no less than 90% of the maximum production achieved in the previous three (3) years.

Monitoring - Continuous Emissions Monitoring

21. The owner/operator shall install, calibrate, maintain, and operate a continuous monitoring system for measuring nitrogen oxides, oxygen and carbon monoxide emissions discharged to the atmosphere from each turbine stack and record the output of the system. The monitoring system shall be used for measuring and determining compliance. The continuous monitoring system shall comply with applicable provisions of UAC, R307-170 and applicable Federal regulations for the Acid Rain Program under Clean Air Act Title IV.

22. Spring Canyon Energy, LLC shall submit for review and Executive Secretary approval CEMs monitoring plan 45 days before the turbine become operational. The plan shall address the number of monitors to be used, the method of measuring the rate in tons per hour, and the method of calculating emissions during the CEMs breakdowns.

Records & Miscellaneous

23. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any equipment approved under this Approval Order including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Executive Secretary which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. All maintenance performed on equipment authorized by this AO shall be recorded.

24 The owner/operator shall comply with R307-150 Series Inventories, Testing and Monitoring

25. The owner/operator shall comply with R307-107. General Requirements Unavoidable Breakdowns.

The Executive Secretary shall be notified in writing if the company is sold or changes its name.

Under R307-150-1, the Executive Secretary may require a source to submit an emission inventory for any full or partial year on reasonable notice.

This AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including R307.

A copy of the rules, regulations and/or attachments addressed in this AO may be obtained by contacting the Division of Air Quality The Utah Administrative Code R307 rules used by DAQ, the Notice of Intent (NOI) guide, and other air quality documents and forms may also be obtained on the Internet at the following web site http //www.deq state ut us/eqair/aq_home htm

The annual emission estimations below include point source and do not include fugitive emissions, fugitive dust, road dust, tail pipe emissions, etc. These emissions are for the purpose of determining the applicability of Prevention of Significant Deterioration, non-attainment area, maintenance area, and Title V source requirements of the R307 They are not to be used for determining compliance

The Potential To Emit (PTE) emissions for this source (the entire plant, or specify what portion) are currently calculated at the following values

Pollutant		Tons/yr
A.	PM_{10}	70 9
B	SO_2	5 3
C.	NO_x	66 4
D	CO	97 5
E.	VOC	67 12

HAPs

Acetaldehyde	0.015
Acrolein	0.015
1,3 Butadiene	0.017
Benzene	0.17
Ethylbenzene	1.35
Formaldehyde	1.51
Naphthalene	0.01
PAH	0.002
Propylene Oxide	1.20
Toluene	1.12
Xylenes	0.26
Totals	5.7

Approved By:

RW Sprott

Richard W. Sprott, Executive Secretary
Utah Air Quality Board

State of Utah
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RIGHTS

Michael O. Leavitt
Governor
Robert L. Morgan
Executive Director
Jerry D. Olds
State Engineer

1594 West North Temple, Suite 220
PO Box 146300
Salt Lake City, Utah 84114-6300
(801) 538-7240 telephone
(801) 538-7467 fax
www.nr.utah.gov

MULTIPLE APPLICANTS
START CARDS SENT TO
ANOTHER APPLICANT

December 13, 2002

Spring Canyon Energy L.L.C. 53-97
P.O. Box 774000 #359
Steamboat Springs, CO 80477

Dear Applicant:

RE: APPROVED CHANGE APPLICATION
NUMBER 53-97 (a27090)

This is your authority to develop the water under the above referenced application which under Sections 73-3-10 and 73-3-12, Utah Code Annotated, 1953, as amended, must be diligently prosecuted to completion. The water must be put to beneficial use and proof of beneficial use be made to the State Engineer on or before December 31, 2005; otherwise, the application will be lapsed.

Proof of beneficial use is evidence to the State Engineer that the wate has been placed to its full intended beneficial use. By law, it must be prepared by a registered engineer or land surveyor, who will certify to the location and the uses for the water. Your proof of change will become the basis for the extent of your water right.

Utah water law provides that to maintain a water right's validity, the water must be benefically used. The filing of a change application does not excuse placing the water to beneficial use or protect the right from challenge of partial or total forfeiture.

Failure on your part to comply with the requirements of the statutes may result in forfeiture of this application. It is the applicant's obligation to maintain a current address with this office. Please notify this office immediately of any change.

Also enclosed are two post cards. You must give the Driller (Start) Card to the licensed driller with whom you contract to construct the well(s). The other card is the Applicant Card which is your responsibility to sign and return to this office immediately after final completion of the well. CAUTION: There may be local health department requirements for the actual siting of your well. Please check with the proper local authority before construction begins.

Your contact with this office, should you need it, is with the Utah Lake/Jordan River Regional Office. The telephone number is (801)538-7421.

Sincerely,

Jerry D. Olds

Jerry D. Olds, P.E.
State Engineer

Utah!

Encl.: Memorandum Decision

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10103

BEFORE THE STATE ENGINEER OF THE STATE OF UTAH

IN THE MATTER OF CHANGE APPLICATION	)	
	)	MEMORANDUM DECISION
NUMBER 53-97 (a27090)	)	

Change Application Number 53-97 (a27090) in the names of R Blake Garrett and Spring Canyon Energy L L C , was filed on September 17, 2002, to change the point of diversion, place of use, and nature of use of 3 0 cfs of water Heretofore, the water has been diverted from a well located North 1354 feet and West 48 feet from the S¼ Corner of Section 31, T12S, R1E, SLB&M, and used for the irrigation of 107 00 acres from April 1 to October 31 in the, W½NW¼ of Section 31, T12S, R1E, SLB&M., S½NE¼ of Section 36, T12S, R1W, SLB&M

Hereafter, it is proposed to divert 3 0 cfs of water from an existing 8-inch well and four proposed 16-inch well 100 to 1000 feet deep Although eight locations are described, only four will be drilled These are to be located. (1) North 2000 feet and East 1300 feet from the SW Corner of Section 30, T11S, R1E, SLB&M,; (2) North 2615 feet and West 660 feet; (3) North 2615 feet and West 25 feet, (4) North 1980 feet and West 25 feet; (5) North 1345 feet and West 25 feet, (6) North 1345 feet and West 660 feet; (7) North 2615 feet and West 1295 feet, (8) North 1980 feet and West 1295 feet, and (9) North 1345 feet and West 1295 feet, all eight from the SE Corner of Section 23, T11S, R1W, SLB&M The water is to be used for steam generation at the Spring Canyon Project with a rated capacity of 530 megawatts and other incidental uses at the Spring Canyon Energy Project including domestic and other uses in the NE¼SE¼ of Section 23, T11S, R1W, SLB&M

The application was advertised in The Nephi Times News on October 9 and 16, 2002, and was protested by the United States Bureau of Reclamation In the written protest concern is expressed that no increase in depletion should be allowed by this change application

The State Engineer has reviewed the change application, the underlying water right, the protest and the extant literature on groundwater in the area The historic water right is for the irrigation of 107 acres, however, 96 acres are solely supplied under this right The balance is covered by shares of stock in the Nephi Irrigation Company This use would require a diversion of 384 acre-feet of water (96 acres X 4 0 acre-feet per acre) and would have consumed a total of 210 24 acre-feet of water (96 acres X 2 19 acre feet per acre) The remainder of the water returned to the hydrologic system The proposed use basically industrial steam power generation and industrial use has not been quantified for the amount of water that would be depleted from the hydrologic system The applicants have enumerated a total of nine wells sites however from the comments submitted in the application only four wells will be drilled The applicants have met all of the criteria governing change applications and it appears if conditions are imposed, this change application can be approved.

In evaluating the various elements of the underlying rights, it is not the intention of the State Engineer to adjudicate the extent of these rights, rather to provide sufficient definition of the rights to assure that other vested rights are not impaired by the change and no enlargement occurs. If, in a subsequent action, the court adjudicates that this right is entitled to either more or less water, the State Engineer will adjust the figures accordingly.

It is, therefore, ORDERED and Change Application Number 53-97 (a27090) is hereby APPROVED subject to prior rights and the following conditions:

1. This change application is limited to a total diversion of 384 acre-feet annually and to the depletion of 210.24 acre-feet annually.

2. Upon submittal of proof of change, in addition to all other information required at that time, the applicants shall provide evidence that the diversion and depletion limits have not been exceeded and that the historic uses have been eliminated.

3. The applicants shall install permanent totalizing meters on all wells and on all water that is being allowed to recharge the groundwater or being placed back to the natural stream environment. The applicants shall keep at least monthly records of all water diverted from the wells and water being returned. The meters and the records shall be available to the State Engineer or his representative at all reasonable times as may be required to regulate this change application.

4. The applicants are responsible for obtaining all other permits from the appropriate entities that will be required for this type of water use.

This Decision is subject to the provisions of Rule R655-6-17 of the Division of Water Rights and to Sections 63-46b-13 and 73-3-14 of the Utah Code Annotated, 1953, which provide for filing either a Request for Reconsideration with the State Engineer or an appeal with the appropriate District Court. A Request for Reconsideration must be filed with the State Engineer within 20 days of the date of this Decision. However, a Request for Reconsideration is not a prerequisite to filing a court appeal. A court appeal must be filed within 30 days after the date of this Decision, or if a Request for Reconsideration has been filed, within 30 days after the date the Request for Reconsideration is denied A Request for Reconsideration is considered denied when no action is taken 20 days after the Request is filed.

Dated this 13th day of December, 2002.

Jerry D. Olds

Jerry D. Olds, P.E., State Engineer

JDO:JER:kkh

Mailed a copy of the foregoing Memorandum Decision this 13th day of December, 2002, to:

R. Blake Garrett
North Airport Road
Mona, UT 84648

Spring Canyon Energy L.L.C.
P.O. Box 774000 #359
Steamboat Springs, CO 80477

Jody Williams
Holme, Roberts and Owen LLP
229 South Main Street, Suite 1800
Salt Lake City, UT

Bureau of Reclamation
c/o Jonathan B. Jones
302 East 1860 South
Provo, UT 84606-7317

Division of Water Quality
PO Box 144870
Salt Lake City, UT 84116

Water User Program
Division of Water Rights

BY: Kelly K. Horne

Kelly K Horne, Secretary

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State of Utah
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RIGHTS

Michael O Leavitt
Governor
Robert L Morgan
Executive Director
Jerry D Olds
State Engineer

1594 West North Temple, Suite 220
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Salt Lake City, Utah 84114-6300
(801) 538-7240 telephone
(801) 538-7467 fax
www nr utah.gov

January 22, 2003

Spring Canyon Energy L.L.C. 53-1431
P.O. Box 774000 #359
Steamboat Springs, CO 80477

Dear Applicant:

RE: APPROVED CHANGE APPLICATION
NUMBER 53-1431 (a27051)

This is your authority to develop the water under the above referenced application which under Sections 73-3-10 and 73-3-12, Utah Code Annotated, 1953, as amended, must be diligently prosecuted to completion. The water must be put to beneficial use and proof of beneficial use filed with the State Engineer, as provided in the original application, a21754, with the proof-due date of March 31, 2007, as amended by this approved change application.

Failure on your part to comply with the requirements of the statutes may result in forfeiture of this application. It is the applicant's obligation to maintain a current address with this office. Please notify this office immediately of any change.

Also enclosed are two post cards. You must give the Driller (Start) Card to the licensed driller with whom you contract to construct the well(s). The other card is the Applicant Card which is your responsibility to sign and return to this office immediately after final completion of the well. CAUTION: There may be local health department requirements for the actual siting of your well. Please check with the proper local authority before construction begins.

Your contact with this office, should you need it, is with the Utah Lake/Jordan River Regional Office. The telephone number is (801)538-7421.

Sincerely,

Jerry D Olds

Jerry D. Olds, P.E.
State Engineer

JDO:et

Encl.: Memorandum Decision

BEFORE THE STATE ENGINEER OF THE STATE OF UTAH

IN THE MATTER OF CHANGE APPLICATION)
) MEMORANDUM DECISION
NUMBER 53-1431 (a27051))

Change Application Number 53-1431 (a27051), in the names of Michael S. Keyte and Spring Canyon Energy L.L.C., was filed on September 3, 2002, to change the point of diversion, place of use, and nature of use of 163.22 acre-feet of water. Heretofore, the water has been diverted from three wells located: (1) North 2300 feet and East 1300 feet; (2) North 2010 feet and East 1300 feet; and (3) North 2000 feet and East 1300 feet all from the SW Corner of Section 30, T11S, R1E, SLB&M. The water has been used for the irrigation of 40.00 acres from April 1 to October 31, the watering of 83 cattle or equivalent, and the domestic purposes of two families in the S½NW¼ and the N½SW¼ of Section 30, T11S, R1E, SLB&M.

Hereafter, it is proposed to divert 163.22 acre-feet of water from four wells, although nine wells are described only four will be drilled, located: (1) North 2000 feet and East 1300 feet from the SW Corner of Section 30, T11S, R1E, SLB&M.; (2) North 2615 feet and West 660 feet; (3) North 2615 feet and West 25 feet; (4) North 1980 feet and West 25 feet; (5) North 1345 feet and West 25 feet; (6) North 1345 feet and West 660 feet; (7) North 2615 feet and West 1295 feet; (8) North 1980 feet and West 1295 feet; and (9) North 1345 feet and West 1295 feet all eight from the SE Corner of Section 23, T11S, R1W, SLB&M. The water is to be used for steam generation at the Spring Canyon Project with a rated capacity of 530 megawatts and other incidental uses at the Spring Canyon Energy Project including domestic and other uses in the NE¼SE¼ of Section 23, T11S, R1W, SLB&M.

The application was advertised in The Nephi Times-News on September 25 and October 2, 2002, and was protested by the United States Bureau of Reclamation. In the written protest concern is expressed that no increase in depletion should be allowed by this change application.

The State Engineer has reviewed the change application, the underlying water right, the protest, and the extant literature on groundwater in the area. The historic water right is for the irrigation of 40 acres, livestock water for 83 cattle or equivalent, and for the domestic use of two families. These uses require a diversion of 163.22 acre-feet of water (40 acres X 4.0 acre-feet per acre + 83 livestock X 0.028 acre-foot per head + two families X 0.45 acre-foot per family). These same uses would have consumed a total of 90.1 acre-feet of water (40 acres X 2.19 acre-feet per acre + 83 livestock X 0.028 acre-foot per head + two families X 0.45 acre-foot per family X 20% depletion). The proposed use, basically industrial steam power generation and industrial use, has not been quantified for the amount of water that can be depleted from the hydrologic system. The applicants have enumerated a total of nine well sites, however, from

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the comments submitted in the application, only four wells will be drilled. The State Engineer is of the opinion that, if appropriate conditions are imposed, this change can be approved without impairing rights of others.

In evaluating the various elements of the underlying rights, it is not the intention of the State Engineer to adjudicate the extent of these rights, rather to provide sufficient definition of the rights to assure that other vested rights are not impaired by the change and no enlargement occurs. If, in a subsequent action, the court adjudicates that this right is entitled to either more or less water, the State Engineer will adjust the figures accordingly.

It is, therefore, ORDERED and Change Application Number 53-1431 (a27051) is hereby APPROVED subject to prior rights and the following conditions:

1. This change application is limited to a diversion of 163.22 acre-feet annually and the depletion of 90.1 acre-feet annually.

2. Upon submittal of proof of change, in addition to all other information required at that time, the applicants shall provide evidence that the diversion and depletion limits have not been exceeded and that the historic uses have been eliminated.

3. The applicants shall install permanent totalizing meters on all wells and shall keep at least monthly records of all water diverted from the wells. The meters and the records shall be available to the State Engineer or his representative at all reasonable times as may be required to regulate this change application.

This Decision is subject to the provisions of Rule R655-6-17 of the Division of Water Rights and to Sections 63-46b-13 and 73-3-14 of the Utah Code Annotated, 1953, which provide for filing either a Request for Reconsideration with the State Engineer or an appeal with the appropriate District Court. A Request for Reconsideration must be filed with the State Engineer within 20 days of the date of this Decision. However, a Request for Reconsideration is not a prerequisite to filing a court appeal. A court appeal must be filed within 30 days after the date of this Decision, or if a Request for Reconsideration has been filed, within 30 days after the date the Request for Reconsideration is denied. A Request for Reconsideration is considered denied when no action is taken 20 days after the Request is filed

MEMORANDUM DECISION
CHANGE APPLICATION NUMBER
53-1431 (a27051)
PAGE 3–

Dated this 22nd day of January, 2003.

Jerry D. Olds

Jerry D. Olds, P.E., State Engineer

JDO·JER:kkh

Mailed a copy of the foregoing Memorandum Decision this 22nd day of January, 2003, to:

Michael S. Keyte
P.O. Box 274
Mona, UT 84645

Spring Canyon Energy L.L.C.
P.O. Box 774000 #359
Steamboat Springs, CO 80477

Jody Williams
Holme, Roberts and Owen LLP
229 South Main Street, Suite 1800
Salt Lake City, UT

Bureau of Reclamation
c/o Jonathan B. Jones
302 East 1860 South
Provo, UT 84606-7317

BY: Kelly K. Horne

Kelly K. Horne, Secretary

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Spring Canyon Energy, L.L.C. Docket No. EG02-183-000

NOTICE OF APPLICATION FOR COMMISSION DETERMINATION OF EXEMPT WHOLESALE GENERATOR STATUS

(September 13, 2002)

On September 10, 2002, Spring Canyon Energy, L.L.C. (the Applicant) whose address is 10440 N. Central Expressway, No. 1400, Dallas, Texas 75231, filed with the Federal Energy Regulatory Commission an application for determination of exempt wholesale generator status pursuant to Part 365 of the Commission's regulations.

The Applicant states that it will be engaged directly or indirectly and exclusively in the business of owning and/or operating a 430 MW (up to 540 MW with duct burners) electric generating facility located near Mona, Utah and selling electric energy at wholesale. The Applicant requests a determination that the Applicant is an exempt wholesale generator under Section 32(a)(1) of the Public Utility Holding Company Act of 1935.

Any person desiring to intervene or to protest this filing should file with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. All such motions or protests should be filed on or before the comment date, and, to the extent applicable, must be served on the applicant and on any other person designated on the official service list. This filing is available for review at the Commission or may be viewed on the Commission's web site at http://www.ferc.gov, using the "FERRIS" link. Enter the docket number excluding the last three digits in the docket number filed to access the document. For assistance, call (202) 502-8222 or TTY, (202) 502-8659. Protests and

interventions may be filed electronically via the Internet in lieu of paper; see 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's web site under the "e-Filing" link. The Commission strongly encourages electronic filings.

Comment Date: October 4, 2002

Magalie R. Salas
Secretary

Transaction & Proforma Assumptions

It is anticipated that the Spring Canyon Energy project will provide power sales to PacifiCorp in accordance with a long-term contract (20-years plus two optional periods of 5-years each). The base case proforma included in Section 5 is representative of the discussions and negotiations with PacifiCorp and includes the following salient business points:

- PacifiCorp will purchase 100% of the output of the Facility and will have full dispatch rights consistent with manufacturers requirements.

- A capacity payment will be made which allows an 18% pre-tax return to equity assuming that lenders will require one-third equity and assuming a debt rate of 7.5% with a 20-year amortization. The base case proforma assumes a capacity payment of $8.00/kw.mo utilizing the base capacity of 420 Mw (which is equivalent to $6.25/kw.m capacity payment utilizing the full plant capacity of 539 Mw).

- Since it is further assumed that lenders will insist upon a 5-year balloon refinancing, the capacity payment will be adjusted for any lender required refinancings as well as for interest rate changes prior to the close of construction and term financing. The interest rate for construction financing is assumed to be 5.5%.

- Fuel cost will be a direct pass through subject to the project meeting a specified heat rate, which is expected to be the EPC guarantee plus 300 Btu/kw.h. If the actual heat rate (adjusted for ambient temperature and normal degradation) is above the specified heat rate, the project will absorb the additional fuel cost (which will be recoverable from the EPC contractor) and if the actual heat rate is below the specified heat rate, the project will receive a benefit. The heat-rate benefit is expected to be approximately $2 million per year based on a $3.50/mmBtu gas price.

- A Fixed O&M payment and a Variable O&M payment will be made which are intended to provide compensation for all fixed and variable costs.

- In order to compensate the project for excellence, there will be a bonus payment for start-ups, which are achieved within specified timeframes and a bonus payment for achieving high levels of plant availability. The base case proforma assumes that the project receives $20,000 for each on-time start but that none of the starts-ups are achieved within the specified timeframe. The base case proforma assumes that availability above 90% will be rewarded at the rate of $1 million for each percentage above 90%. While availability above 95% is anticipated, the base case proforma assumes 90.0%. The base case proforma further assumes that the operator earns a bonus payment. Therefore, these bonus revenue payments represent significant upside potential.

The facility is expected to operate in a typical intermediate plant mode of Monday through Friday, 18 hours per day. The Fixed and Variable O&M payments allow for full recovery of operating expense including a $500,000 contingency in Fixed O&M expense and a $500,000 contingency in Variable O&M expense.

The Project in intended to provide PacifiCorp with a reliable and flexible source of generation, which as a result of its access to Rocky Mountain natural gas, provides competitively priced energy. The transaction is intended to result in a low risk 18% pre-tax return to equity with significant upside potential to reward excellent performance.

Spring Canyon Energy
Financial Assumptions

Construction Financing Assumptions

Construction Costs:		$	317,709,000
Interest rate:	5.50%		
Construction Period (6, 12, 18, 24, 30, or 36 Mo)	24		
Legal Fees:	1.00%	$	3,177,090
Total Financed during Constr:		$	320,886,090
Interest Expense during const		$	24,002,280
Commitment Fees:	1.00%	$	2,053,671
Debt reserve (approx. 6 mo)		$	8,500,000
Amount Financed after Construction		$	355,442,041

Senior Debt Financing Assumptions

Percent of Total Financing	66.67%		
Senior Debt:		$	236,973,208
Amortization Term (Yrs)	20		
Interest Rate:	7.50%		
Amort Method (Straight-line, Mortgage, Variable)			Mortgage

Equity Financing Assumptions

Equity Investment:	Total:	Outside:	USA Power:
% of Total Financing	33.33%	100.00%	0.00%
Total Equity Required:	$ 118,468,832	$118,468,832	$0
Cash Flow Allocation %		100.00%	0.00%
Pre-Tax Equity IRR	18.16%	0.00%	0.00%

Other Financing Assumptions:

Expected Financial Closing Date - Senior Debt	Dec-04
Expected Financial Closing Date - Equity	Dec-04
Initial Debt Service Reserve	$8,762,818
Interest Income Rate	6.00%

	Min.	Max.	Avg.
Debt Coverage Ratios (pre-tax)	2.28	2.54	2.38

Spring Canyon Energy
Construction Conceptual Assumptions

Plant Configuration	2x1	2(1x1)
EPC		
Civil Work, Foundation & Buildings	S5 543 950	S5 987 509
Power Island Equipment	S108 927 290	S117 641 473
Balance of Plant, Mechanical	S96 248,500	S103 948 380
Balance of Plant, Electrical & Control	S15 445 000	S16 680 600
Total Direct Cost	$226,164,780	$244,257 962
Spare Parts	S11 031 040	$11,031,040
Engineering & Construction Management	S15 831 535	$15 831,535
Contractor's Overhead & Profit	S10 576 751	$10 576 751
Logistics & Freight	S992,794	S992,794
Tax Allowance	S0	S0
Total EPC	$264 596 900	$282 690 082

Total Project Cost		
Construction Cost		
Turnkey Construction Contract (EPC)	$264 597,000	$282,690,000
Construction Contingency (7 5% of EPC Direct Cost)	$16,962,000	$18,319 000
Fuel Pipeline	S0	S0
Gas Interconnect	$250 000	$250 000
Electrical Transmission Line	$750 000	$750 000
Electrical Interconnect	S2,850 000	$2,650,000
Construction Insurance	$750 000	$750,000
Water Wells	S500 000	$500,000
Sales Tax	S0	S0
Total Construction Cost	$286 459 000	$305 909 000

Development Cost		
Land Acquisition	S250 000	$250 000
Easements & ROW	S100 000	S100 000
Water Acquisition	$2,200 000	$2,200 000
Emission Credits	S1 000 000	$1 000 000
Permitting / Legal/G&A	S? 000 000	$2,000 000
Construction Management	S2,200 000	$2,200 000
Property Tax During Construction	S2 000 000	$2,000 000
Startup	S3 000 000	S3 000 000
Initial Fuel Supply	S3 000 000	$3 000 000
Development Fee	S14 000 000	$14 000 000
Contingency	S1 500 000	$1 500 000
Total Development Cost	$31,250 000	$31 250 000
Total Project Cost	**$317 709,000**	**$337 159 000**

Notes

Equipment Description *

201 = Two 7FA on one Steam Turbine

2 GE Fr7FA Turbine

1-GE Steam Turbine

1 HRSG — Air Cooled

202 = Two 7FA Turbines on two Steam turbines

2 GE Fr7FA Turbines

2-GE Steam Turbines — Air Cooled

HRSG

10104

CONSTRUCTION PERIOD DRAW-DOWN SCHEDULE

Construction Period	24
Construction Loan Amount	$320 886 090
Construction Loan Rate	5 50%
Commitment Fee (%)	1 00%

No	Month	Draw %	Principal O S	Unused Principal	Months to Comm Oprs	Commitment Fee	IDC	Cum IDC
1 00	Jun-03	15 0%	$48 132,914	$272,753 177	24 00	$227 294	$5,294 620	$5 294 620
2 00	Jul-03	10 0%	$32 088 609	$240 664 568	23 00	$200 554	$3 382,674	$8 677 295
3 00	Aug-03	8 0%	$19 253 165	$221 411 402	22 00	$184,510	$1 941 361	$10 618 656
4 00	Sep-03	8 0%	$19 253 165	$202 158 237	21 00	$168 465	$1 853 117	$12,471 773
5 00	Oct 03	8 0%	$19 253 165	$182 905 071	20 00	$152 421	$1 764 873	$14 236 646
6 00	Nov-03	5 0%	$18 044 305	$166 860 767	19 00	$139 051	$1,397 192	$15 633 838
7 00	Dec-03	5 0%	$16 044 305	$150 818 462	18 00	$125 680	$1 323 655	$16 957 493
8 00	Jan-04	4 0%	$12 835 444	$137 981 018	17 00	$114 984	$1 000 095	$17 957 588
9 00	Feb-04	4 0%	$12,835 444	$125 145 575	16 00	$104,288	$941,286	$18 898 854
10 00	Mar-04	4 0%	$12 835 444	$112 310 132	15 00	$93 592	$882,437	$19 781,290
11 00	Apr 04	3 0%	$9 626 583	$102 683 549	14 00	$85 570	$617 706	$20 398 998
12 00	May 04	3 0%	$9 626 583	$93 058 966	13 00	$77 547	$573 584	$20 972,580
13 00	Jun-04	3 0%	$9 628 583	$83 430 383	12 00	$69 525	$529 462	$21,502 042
14 00	Jul-04	3 0%	$9 626 583	$73 803 801	11 00	$61,503	$485 340	$21,987 382
15 00	Aug-04	3 0%	$9 626 583	$64 177 218	10 00	$53 481	$441 218	$22 428 601
16 00	Sep-04	3 0%	$9 626 583	$54 550 635	9 00	$45 459	$397 097	$22 825 697
17 00	Oct-04	3 0%	$9 626 583	$44 924 053	8 00	$37 437	$352,975	$23 178 672
18 00	Nov-04	2 0%	$8 417 722	$38 506 331	7 00	$32 089	$205 902	$23 384 574
19 00	Dec-04	2 0%	$6 417 722	$32,088 609	6 00	$26 741	$176 487	$23 561 061
20 00	Jan-05	2 0%	$8 417 722	$25 670 887	5 00	$21 392	$147 073	$23 708 134
21 00	Feb-05	2 0%	$8 417 722	$19 253 165	4 00	$16 044	$117 658	$23 825 792
22 00	Mar-05	2 0%	$8 417 722	$12 835 444	3 00	$10 696	$88,244	$23 914 036
23 00	Apr 05	2.0%	$6 417 722	$6 417 722	2 00	$5 348	$58 829	$23,972 865
24 00	May 05	2 0%	$6 417 722	($0)	1 00	($0)	$29 415	$24 002 280
25 00								
26 00								
27 00								
28 00								
29 00								
30 00								
31 00								
32 00								
33 00								
34 00								
35 00								
36 00								
Total		100 0%	$320,886,090			$2 053 671	$24 002,280	

Draw Down Percentages

No	6-Month	12 Month	18-Month	24-Month	30-Month	36-Month
1 00	30 0%	25 0%	20 0%	15 0%	8 0%	6 0%
2.00	25 0%	20 0%	15 0%	10 0%	7 0%	6 0%
3 00	15 0%	10 0%	10 0%	6 0%	7 0%	5 0%
4 00	15 0%	7 0%	8 0%	6 0%	6 0%	5 0%
5 00	10 0%	7 0%	7 0%	6 0%	6 0%	5 0%
6 00	5 0%	6 0%	6 0%	5 0%	6 0%	5 0%
7 00		6 0%	5 0%	5 0%	5 0%	5 0%
8 00		5 0%	4 0%	4 0%	5 0%	4 0%
9 00		5 0%	3 0%	4 0%	5 0%	4 0%
10 00		4 0%	3 0%	4 0%	4 0%	4 0%
11 00		3 0%	3 0%	3 0%	4 0%	4 0%
12.00		2.0%	3 0%	3 0%	4 0%	4 0%
13 00			3 0%	3 0%	3 0%	3 0%
14 00			2 0%	3 0%	3 0%	3 0%
15 00			2.0%	3 0%	3 0%	3 0%
16 00			2.0%	3 0%	3 0%	2 0%
17 00			2 0%	3 0%	3 0%	3 0%
18 00			2 0%	2 0%	2.0%	3 0%
19 00				2 0%	2 0%	2 0%
20 00				2 0%	2 0%	2 0%
21 00				2 0%	2.0%	2 0%
22.00				2 0%	2 0%	2 0%
23 00				2 0%	1 0%	2 0%
24 00				2.0%	1 0%	2 0%
25 00					1 0%	2 0%
26 00					1 0%	2.0%
27 00					1 0%	1 0%
28 00					1 0%	1 0%
29 00					1 0%	1 0%
30 00					1 0%	1 0%
31 00						1 0%
32.00						1 0%
33 00						1 0%
34 00						1 0%
35 00						1 0%
36 00						1 0%
Total	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%

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ICIAL PROJECTIC
ONFIGURATION
L PROJECT COST $355,442,041

4/2/03

		1	2	3	~	5	6	7	8	9	10
		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
IMPTIONS REVENUE											
A ELECTRIC ENERGY REVENUE											
1 MW BASE CAPACITY		420	420	420	420	420	420	420	420	420	420
MW PEAKING CAPACITY	100%	539	539	539	539	539	539	539	539	539	539
2 ANNUAL OPERATING HOURS											
18 hr/d,5d/wk,52 wkp/yr		1,880	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680
		0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0
Total Operating Hours		4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680
Cumulative Equivalent Operating Hours		4,680	9,360	14,040	23,153	27,033	32,513	37,193	41,873	46,553	51,233
3 KWH SOLD 000 s											
KWH		1,967,846	1,967,846	1,967,846	1,967,846	1,987,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846
		0	0	0	0	0	0	0	0	0	0
Total KWh Sold		1,987,846	1,987,846	1,967,846	1,967,848	1,967,846	1,987,846	1,967,846	1,967,846	1,967,846	1,967,846

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CIAL PROJECTIC
NFIGURAT ON
PROJECT COST $300,412,041

4/2/03

			2	3	[illegible]	5	6	7	8	[illegible]	[illegible]
		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
CAPACITY REVENUE											
Base Capacity MW		420	420	420	420	420	420	420	420	420	420
Capac ty Payment	$kw yr	$96 00	$96 00	$96 00	$96 00	$98 00	$96 00	$96 00	$96 00	$96 00	$96 00
		0 000	0 000	0 000	0 000	0 000	0 000	0 000	0 000	0 000	0 000
Tota Capacity Revenue		40 366 080	40 366 080	40 366 080	40 366 080	40 366 080	40 366 080	40 366 080	40 366 080	40 366 080	40 366 080
FIXED O&M REVENUE											
Base Capacity MW		420	420	420	420	420	420	420	420	420	420
Fixed O&M Payment ($20 928/kw yr)		$21 773	$22.208	$22 653	$23 106	$23 568	$24 039	$24 520	$25 010	$25.511	$26 021
Esca a es with General Inflation											
Tota Fixed O&M Revenue		9 155 111	9 338 213	9 524 878	9 715 477	9 909 787	10 107 982	10 310 142	10 516 345	10 726 672	10 941 205
) **VAR ABLE O&M REVENUE**											
Base Capacity MW		420	420	420	420	420	420	420	420	420	420
Tota Cummu ative Operl ng Hours		4 680	4 680	4 680	4 680	4 680	4 680	4 680	4 680	4 680	4 680
Va able O&M Payment ($4 410/mw h)		$4 508	$4 680	$4 773	$4 869	$4 966	$5 066	$5 167	$5 270	$5 376	$5 483
Escala es with General nflation											
Total Variable O&M Revenue		9 028 479	9 209 049	9 393 230	9 581 094	9 772 716	9 968 171	10 167 534	10 370 885	10 578 302	10 789 868
E. **HEAT RATE BENEFIT**											
Hea Rate Benef t	300 00	2 036 465	2 133 317	[illegible] 170 908	2 209 [illegible]17	2 248 355	2 288 21[illegible]	2 328 933	[illegible] 370 435	2 112 7C7	2 455 915
300 btus /kwhr op hrs kw/1000 gas price											
F **FUEL PAYMENT (Pass Th ough)**		51 413 607	52,317 370	53 239 208	54 179 483	55 138 664	56 116 826	57 114 653	58 132,437	59 170 577	60 229 479
G **START UP BONUS**											
START UP REVENUE FACTOR											
# On Tir e Starts		0	0	0	0	0	0	0	0	0	0
$ 20 000/On Time Start		20 808	21 224	21 649	22,082	22 523	22,974	23 433	23 902	24 380	24 867
START UP BONUS		0	0	0	0	0	0	0	0	0	0
H **AVAILABILITY BONUS**											
Bonus Facto ($1 000 000/% avail >90%)		0 00%	0 00%	0 00%	0 00%	0 00%	0 00%	0 00%	0 00%	0 00%	0 00%
Bonus Facto Earned		0 00%	0 00%	0 00%	0 00%	0 00%	0 00%	0 00%	0 00%	0 00%	0 00%
Ava abl lty Bonus		0	0	0	0	0	0	0	0	0	0

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OJECT SPRING C
IANCIAL PROJECTIC
I CONFIGURATION
TAL PROJECT COST

		1	2	3	[illegible]	5	6	7	8	9	10
TAL PROJECT COST	$355,442,041	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
ISUMPTIONS EXPENSES											
A. FUEL											
1 FUEL CONSUMPTION											
Base Heat Rate 7169 Btu/kw h(HHV)		7,169	7,159	7,169	7,159	7,159	7,159	7,159	7,159	7,159	7,169
KWH Produced (000's)		1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846
Fuel Usage-Before Start-Up Gas (000's mmBtu (HHV))		14,088	14,088	14,088	14,088	14,088	14,088	14,088	14,088	14,088	14,088
Start Up Gas (Hot Start)	750mmbtu's/turbine/s	390	390	390	390	390	390	390	390	390	390
TOTAL GAS USED IN OPERATIONS		14,478	14,478	14,478	14,478	14,478	14,478	14,478	14,478	14,478	14,478
2. FUEL COST PER UNIT											
Rate $/mmBtu (HHV) $3 00		3 121	3 184	3 247	3.312	3.378	3.446	3.515	3 585	3.657	3.730
Transportation $/mmBtu (HHV)		0 430	0.430	0.430	0.430	0.430	0.430	0.430	0 430	0 430	0.430
TOTAL FUEL PRICE		3 551	3,614	3 677	3 742	3 808	3.876	3.945	4 016	4 087	4.160
TOTAL FUEL EXPENSE		51,413,607	52,317,370	53,239,208	54,179,483	55,138,564	56,116,826	57,114,653	58,132,437	59,170,577	60,229,479
B VARIABLE COSTS											
Chemical Lubricant & Ammonia Cost **($/Mwh)**		0 2142	0.2185	0 2229	0.2273	0 2319	0.2365	0 2412	0.2460	0 2510	0.2560
Contingency ($/Mwh)		0 3200	0.3331	0 3398	0 3466	0 3535	0.3606	0.3678	0.3752	0 3827	0.3903
C. FIXED COSTS											
Property and Other Taxes	1.1600%	2,623,611	2,676,982	2,729,501	2,784,091	2,839,773	2,896,569	2,954,500	3,013,690	3,073,862	3,135,339
O&M Labor		1,690,650	1,724,463	1,768,952	1,784,131	1,830,014	1,866,614	1,903,946	1,942,025	1,980,866	2,020,483
Compliance & Professional Fees		26,010	26,530	27,061	27,602	28,154	28,717	29,291	29,877	30,476	31,084
General & Administrative (GP)		780,300	795,906	811,824	828,061	844,622	861,514	878,745	896,319	914,246	932,531
Operator Fee		312,120	318,362	324,730	331,224	337,849	344,606	351,498	358,528	365,698	373,012
Operator Bonus		728,280	742,846	757,703	772,857	788,314	804,080	820,162	836 565	853,296	870,362
Management Fee (GP)		260,100	265,302	270,608	276,020	281,541	287,171	292,915	298,773	304,749	310,844
Insurance		1,872,720	1,910,174	1,948,378	1,987,345	2,027,092	2,067,634	2,108,987	2,151,167	2,194,190	2,238,074
Contingency		520,200	530,604	541,216	552,040	563,081	574,343	585,830	597,646	609,497	621,687

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OJECT: SPRING (
IANCIAL PROJECTI(
I CONFIGURATION
TAL PROJECT COST $338,442,041

		1	2	3	4	5	6	7	8	9	10
		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
D. VARIABLE O&M RESERVE											
ANNUAL OVERHAUL RESERVES											
GT Insp/OH Reserve	$890	6,505,013	6,635,113	6,767,815	6,903,172	7,041,235	7,182,060	7,325,701	7,472,215	7,621,659	7,774,092
$668/hr /turbine x 2										0	0
ST Insp/OH Reserve	$187	782,529	798,179	814,143	830,426	847,034	863,975	881,254	898,880	916,857	935,194
$ 9 million /56,000 hrs											
SCR Replacement Reserve	$173	811,512	827,742	844,297	861,183	878,407	895,975	913,894	932,172	950,816	969,832
$6 million /36,000 hrs											
Misc. Contingency	0.2643	520,023	530,424	541,032	551,853	562,890	574,148	585,630	597,343	609,290	621,476
$0.2540 /Mwh											
ANNUAL RESERVE ACTIVITY											
GAS TURBINE											
Beginning Balance		0	6,505,013	13,140,126	19,907,941	26,811,113	33,852,348	7,182,060	14,507,761	21,979,976	29,601,635
Annual Accrual		6,505,013	6,635,113	6,767,815	6,903,172	7,041,235	7,182,060	7,325,701	7,472,216	7,621,659	7,774,092
Reserves Used							(33,852,348)				
Ending Balance		6,505,013	13,140,126	19,907,941	26,811,113	33,852,348	7,182,060	14,507,761	21,979,976	29,601,635	37,375,727
STEAM TURBINE											
Beginning Balance		0	782,529	1,580,708	2,394,851	3,225,277	4,072,311	4,936,286	5,817,541	6,716,420	7,633,277
Annual Accrual		782,529	798,179	814,143	830,426	847,034	863,975	881,254	898,880	916,857	935,194
Reserves Used											
Ending Balance		782,529	1,580,708	2,394,851	3,225,277	4,072,311	4,936,286	5,817,541	6,716,420	7,633,277	8,568,472
SCR											
Beginning Balance		0	811,512	1,639,254	2,483,551	3,344,734	4,223,141	5,119,116	6,033,010	932,172	1,882,988
Annual Accrual		811,512	827,742	844,297	861,183	878,407	895,976	913,894	932,172	950,816	969,832
Reserves Used									(6,033,010)		
Ending Balance		811,512	1,639,264	2,483,551	3,344,734	4,223,141	5,119,116	6,033,010	932,172	1,882,988	2,852,820
MISC CONTIGENCY											
Beginning Balance		0	520,023	1,050,447	541,032	1,092,885	562,890	1,137,037	585,630	1,182,974	609,290
Annual Accrual		520,023	530,424	541,032	551,853	562,890	574,140	585,630	597,343	609,290	621,476
Reserves Used				(1,050,447)		(1,092,885)		(1,137,037)		(1,182,974)	
Ending Balance		520,023	1,050,447	541,032	1,092,885	562,890	1,137,037	585,630	1,182,974	609,290	1,230,766
TOTAL OVERHAUL RESERVE											
Beginning Balance		0	8,619,077	17,410,535	25,327,376	34,474,009	42,710,690	18,374,499	26,943,942	30,811,542	39,727,190
Annual Accrual		8,619,077	8,791,458	8,967,287	9,146,633	9,329,566	9,516,167	9,706,480	9,900,610	10,098,622	10,300,594
Reserves Used		0	0	(1,050,447)	0	(1,092,885)	(33,852,348)	(1,137,037)	(6,033,010)	(1,182,974)	0
Ending Balance		8,619,077	17,410,535	25,327,378	34,474,009	42,710,690	18,374,499	26,943,942	30,811,542	39,727,190	50,027,784
DEBT RESERVE (FROM BELOW)		8,762,818	8,762,818	8,762,818	0	0	0	0	0	0	0
WORKING CAP RESERVE (BELOW)		0	0	0	0	0	0	0	0	0	0
TOTAL RESERVE FUNDS		17,381,894	26,173,352	34,090,193	34,474,009	42,710,691	18,374,500	26,943,943	30,811,543	39,727,191	50,027,786
INTEREST INCOME	1.50%	130,364	326,664	451,977	514,232	578,865	458,139	339,888	433,166	629,041	673,162
ESCALATION FACTORS											
GAS ESCALATION		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
GENERAL INFLATION		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
PROPERTY TAXES		1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%

4/2/03

4/2/03

		1	2	3	4	5	6	7	8	9	10
JECT: SPRING / N											
ANCIAL PROJECTI(											
CONFIGURATION											
TAL PROJECT COST	$366,442,041	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
OME AND CASHFLOW STATEMENT											
ECTRIC REVENUE:											
Capacity Sales		40,366,080	40,366,080	40,366,080	40,366,080	40,366,080	40,366,080	40,366,080	40,366,080	40,366,080	40,366,080
Fixed O&M Revenue		9,155,111	9,338,213	9,524,978	9,715,477	9,909,787	10,107,982	10,310,142	10,516,345	10,726,672	10,941,205
Variable O&M Revenue		9,028,479	9,209,049	9,393,230	9,581,094	9,772,716	9,968,171	10,167,534	10,370,885	10,578,302	10,789,868
Heat Rate Benefit		2,096,465	2,133,317	2,170,906	2,209,247	2,248,355	2,288,245	2,328,933	2,370,435	2,412,767	2,455,945
Fuel Payment		51,413,607	52,317,370	53,239,208	54,179,483	55,138,564	56,116,826	57,114,653	58,132,437	59,170,577	60,229,479
Availability Bonus Payment		0	0	0	0	0	0	0	0	0	0
Startup Payment		0	0	0	0	0	0	0	0	0	0
		112,059,742	113,364,029	114,694,402	116,051,382	117,435,602	118,847,305	120,287,343	121,756,182	123,254,398	124,782,578
ITEREST REVENUE		130,364	326,664	451,977	514,232	578,885	458,139	339,888	433,166	529,041	673,162
OTAL REVENUE		112,190,107	113,690,694	115,146,379	116,565,614	118,014,388	119,305,443	120,627,231	122,189,348	123,783,438	125,455,740
PERATING EXPENSES											
Fuel Costs		51,413,607	52,317,370	53,239,208	54,179,483	55,138,564	56,116,826	57,114,653	58,132,437	59,170,577	60,229,479
Property and Other Taxes		2,623,511	2,675,982	2,729,501	2,784,091	2,839,773	2,896,569	2,954,500	3,013,590	3,073,862	3,135,339
O&M Labor		1,690,650	1,724,463	1,758,952	1,794,131	1,830,014	1,866,614	1,903,946	1,942,025	1,980,866	2,020,483
Compliance & Professional Fees		26,010	26,530	27,061	27,602	28,164	28,717	29,291	29,877	30,475	31,084
General & Administrative		780,300	795,906	811,824	828,061	844,622	861,514	878,745	896,319	914,246	932,531
Operator Fee		312,120	318,362	324,730	331,224	337,849	344,606	351,498	358,528	365,698	373,012
Operator Bonus		728,280	742,846	757,703	772,857	788,314	804,080	820,162	836,565	853,296	870,362
Management Fee		260,100	265,302	270,608	276,020	281,541	287,171	292,915	298,773	304,749	310,844
Insurance		1,872,720	1,910,174	1,948,378	1,987,345	2,027,092	2,067,634	2,108,987	2,151,167	2,194,190	2,238,074
Chem, Lubricant&Ammonia		421,513	429,943	438,542	447,313	456,259	465,384	474,692	484,186	493,869	503,747
Contingency		520,200	530,604	541,216	552,040	563,081	574,343	585,830	597,546	609,497	621,687
		60,649,011	61,737,483	62,847,723	63,980,168	65,135,262	66,313,458	67,515,218	68,741,014	69,991,325	71,266,642
OPERATING CASHFLOW		51,541,095	51,953,211	52,298,656	52,585,446	52,879,125	52,991,985	53,112,013	53,448,334	53,792,113	54,189,098
DEBT SERVICE REQUIREMENTS											
Principal Payment on Debt		5,322,418	5,758,449	6,201,589	6,677,905	7,194,507	7,751,394	8,348,196	8,990,764	9,682,725	10,431,561
Interest Payment		17,525,635	17,106,326	16,653,959	16,166,668	15,641,831	15,076,428	14,467,437	13,811,524	13,105,092	12,344,097
		22,848,053	22,864,775	22,855,548	22,844,573	22,836,338	22,827,822	22,813,633	22,802,288	22,787,818	22,775,658
CASHFLOW BEFORE OTHER ITEMS		28,693,042	29,088,437	29,443,108	29,740,873	30,042,787	30,164,163	30,298,380	30,646,046	31,004,296	31,413,440
OTHER ITEMS:											
Fees Payment		0	0	0	0	0	0	0	0	0	0
Contribution to Reserves		(8,619,077)	(8,791,468)	(8,967,287)	(383,816)	(9,329,666)	(9,516,157)	(9,706,480)	(9,900,610)	(10,098,622)	(10,300,594)
Working Capital/other				0	0	0	0	0	0	0	0
		(8,619,077)	(8,791,468)	(8,967,287)	(383,816)	(9,329,666)	(9,516,157)	(9,706,480)	(9,900,610)	(10,098,622)	(10,300,594)
DEBT RESERVE								0			
Release of Debt Reserve					8,762,818						
Refinancing Proceeds											
DISTRIBUTABLE CASHFLOW		20,073,965	20,298,978	20,475,821	38,119,876	20,713,221	20,648,006	20,591,899	20,745,437	20,905,674	21,112,846
EQUITY AMOUNT INVESTED:	$ (118,468,832)	20,073,965	20,296,978	20,475,821	38,119,875	20,713,221	20,648,006	20,591,899	20,745,437	20,905,674	21,112,846
Pre-Tax IRR of Equity (20 years)		18.16%									
OUTSIDE											
USA Power											

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		1	2	3	4	5	6	7	8	9	10
ROJECT: SPRING C											
NANCIAL PROJECTIC											
1 CONFIGURATION											
OTAL PROJECT COST	$355,442,041	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
OTAL PROJECT COST	$355,442,041										
QUITY INVESTED	33.53%										
DISCOUNT RATE	1.16	14,918,226	13,003,415	11,308,614	18,149,369	8,501,581	7,305,874	6,281,054	5,455,074	4,738,973	4,125,807
PRESENT VALUE		14,918,226	27,921,641	39,230,256	57,379,624	65,881,205	73,187,079	79,468,133	84,923,207	89,662,181	93,787,987
NET PRESENT VALUE		-103,550,606	-90,647,191	-79,238,577	-61,089,209	-52,687,627	-45,281,753	-39,000,899	-33,645,625	-28,806,652	-24,680,845
SENIOR DEBT SERVICE											
INTEREST RATES											
Libor Swap Assumption		6.250%	6.25%	6.25%	6.26%	6.25%					
Interest Rate Spreads		1.250%	1.250%	1.250%	1.250%	1.250%					
Effective Years		Yr 1-4	Yr 5-8	Yr 9-12	Yr 13-15	Yr 16-20					
AMORTIZATION SCHEDULE	Tranche A										
QRTR #1 Percentage Amortization		0.55%	0.59%	0.64%	0.69%	0.74%	0.80%	0.86%	0.92%	0.99%	1.07%
QRTR #2 Percentage Amortization		0.56%	0.60%	0.65%	0.70%	0.75%	0.81%	0.87%	0.94%	1.01%	1.09%
QRTR #3 Percentage Amortization		0.56%	0.61%	0.66%	0.71%	0.77%	0.83%	0.89%	0.96%	1.03%	1.11%
QRTR #4 Percentage Amortization		0.58%	0.62%	0.67%	0.72%	0.78%	0.84%	0.91%	0.98%	1.05%	1.13%
Total		2.25%	2.43%	2.62%	2.82%	3.04%	3.27%	3.52%	3.79%	4.09%	4.40%
PRINCIPAL PAYMENTS											
QRTR #1 Principal	Tranche A	1,298,613	1,400,612	1,507,150	1,623,266	1,748,862	1,883,937	2,028,491	2,184,893	2,353,144	2,535,613
QRTR #2 Principal	Tranche A	1,324,680	1,426,579	1,535,586	1,654,073	1,782,039	1,919,483	2,066,406	2,227,548	2,398,169	2,583,008
QRTR #3 Principal	Tranche A	1,324,680	1,452,646	1,564,023	1,684,880	1,815,215	1,955,029	2,106,692	2,267,834	2,443,194	2,632,772
QRTR #4 Principal	Tranche A	1,374,445	1,478,713	1,594,830	1,715,686	1,848,391	1,992,945	2,144,608	2,310,489	2,488,219	2,680,167
Total Principal		5,322,418	5,758,449	6,201,589	6,677,905	7,194,507	7,751,394	8,346,196	8,990,764	9,682,725	10,431,561
Period Beginning Balance	66.67%	236,973,208	231,650,790	225,892,341	219,690,752	213,012,847	205,818,341	198,066,947	189,720,751	180,729,987	171,047,262
Payments		5,322,418	5,758,449	6,201,589	6,677,905	7,194,507	7,751,394	8,346,196	8,990,764	9,682,725	10,431,561
Period Ending Balance		231,650,790	225,892,341	219,690,752	213,012,847	205,818,341	198,066,947	189,720,751	180,729,987	171,047,262	160,615,701
PRINCIPAL PAYMENTS											
Tranch A											
QRTR #1 Principal		1,298,613	1,400,612	1,507,150	1,623,266	1,748,862	1,883,937	2,028,491	2,184,893	2,353,144	2,535,613
QRTR #2 Principal		1,324,680	1,426,579	1,535,586	1,654,073	1,782,039	1,919,483	2,066,406	2,227,548	2,398,169	2,583,008
QRTR #3 Principal		1,324,680	1,452,646	1,564,023	1,684,880	1,815,215	1,955,029	2,106,692	2,267,834	2,443,194	2,632,772
QRTR #4 Principal		1,374,445	1,478,713	1,594,830	1,715,686	1,848,391	1,992,945	2,144,608	2,310,489	2,488,219	2,680,167
Total Principal		5,322,418	5,758,449	6,201,589	6,677,905	7,194,507	7,751,394	8,346,196	8,990,764	9,682,725	10,431,561
Period Beginning Balance		236,973,208	231,650,790	225,892,341	219,690,752	213,012,847	205,818,341	198,066,947	189,720,751	180,729,987	171,047,262
Payments		5,322,418	5,758,449	6,201,589	6,677,905	7,194,507	7,751,394	8,346,196	8,990,764	9,682,725	10,431,561
Period Ending Balance		231,650,790	225,892,341	219,690,752	213,012,847	205,818,341	198,066,947	189,720,751	180,729,987	171,047,262	160,615,701
INTEREST PAYMENTS		1	2	3	4	5	6	7	8	9	10
Interest Rate on Debt (swap amount)		6.25%	6.25%	6.25%	6.26%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%
Spread		1.250%	1.250%	1.250%	1.250%	1.250%	1.250%	1.250%	1.250%	1.250%	1.250%
All-In Rate		7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%
QRTR #1 Interest		4,418,899	4,317,193	4,207,222	4,088,765	3,961,200	3,823,770	3,675,721	3,516,297	3,344,566	3,159,593
QRTR #2 Interest		4,394,061	4,290,444	4,178,430	4,057,751	3,927,786	3,787,780	3,636,976	3,474,531	3,299,600	3,111,162
QRTR #3 Interest		4,369,223	4,263,207	4,149,105	4,026,160	3,893,751	3,751,123	3,597,475	3,432,009	3,253,790	3,061,798
QRTR #4 Interest		4,343,452	4,235,481	4,119,202	3,993,891	3,859,094	3,713,755	3,557,264	3,388,687	3,207,136	3,011,544
Total Interest		17,525,635	17,106,326	16,653,959	16,166,668	15,641,831	15,076,428	14,467,437	13,811,524	13,105,092	12,344,097
Annual Admin						-	-	-	-	-	-
LOC Fee Payment		0	0	0	0	0	0	0	0	0	0
Total Interest and Fees		17,525,635	17,106,326	16,653,959	16,166,668	15,641,831	15,076,428	14,467,437	13,811,524	13,105,092	12,344,097
DEBT RESERVE											
Beginning		8,762,818	8,762,818	8,762,818	8,762,818	0	0	0	0	0	0
Addition			0	0	(8,762,818)	0	0	0	0	0	0
Ending		8,762,818	8,762,818	8,762,818	0	0	0	0	0	0	0
Debt Coverage Ratio		2.266	2.272	2.288	2.302	2.316	2.321	2.328	2.344	2.361	2.379
WORKING CAPITAL RESERVE											
Beginning			0	0	0	0	0	0	0	0	0
Addition to working capital			0	0	4/2/03	0	0	0	0	0	0
Ending		0	0	0	0	0	0	0	0	0	0

ROJECT: SPRING C
IANCIAL PROJECTIO
I CONFIGURATION
OTAL PROJECT COST $356,442,041

4/2/03

		11	12	13	14	15	16	17	18	19	20
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
SSUMPTIONS-REVENUE											
A. ELECTRIC ENERGY REVENUE											
1. MW BASE CAPACITY		420	420	420	420	420	420	420	420	420	420
MW PEAKING CAPACITY	100%	539	539	539	539	539	539	539	539	539	539
2. ANNUAL OPERATING HOURS											
18 hr/d,5d/wk,52 wkp/yr		4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680
		0	0	0	0		0	0	0	0	0
		0	0	0	0		0	0	0	0	0
		0	0	0	0		0	0	0	0	0
Total Operating Hours		4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680
Cumulative Equivalent Operating Hours		55,913	60,593	65,273	69,953	74,633	79,313	83,993	88,673	93,353	98,033
3. KWH SOLD 000's											
KWH		1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846
		0	0	0	0	0	0	0	0	0	0
Total kWh Sold		1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846

P1133
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PROJECT: SPRING C N
FINANCIAL PROJECTIC
2x1 CONFIGURATION
TOTAL PROJECT COST $358,442,041

4/2/03

		11	12	13	14	15	16	17	18	19	20
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
B CAPACITY REVENUE											
Base Capacity MW		420	420	420	420	420	420	420	420	420	420
Capacity Payment	$kw/yr	$96.00	$96.00	$96.00	$96.00	$96.00	$96.00	$96.00	$96.00	$96.00	$96 00
		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Capacity Revenue		40,366,080	40,366,080	40,366,080	40,366,080	40,366,080	40,366,080	40,366,080	40,366,080	40,366,080	40,366,080
C. FIXED O&M REVENUE											
Base Capacity MW		420	420	420	420	420	420	420	420	420	420
Fixed O&M Payment ($20 928/kw yr)		$26.541	$27.072	$27.613	$28.166	$28.729	$29.304	$29.890	$30.487	$31.097	$31.719
Escalates with General Inflation											
Total Fixed O&M Revenue		11,160,029	11,383,230	11,610,894	11,843,112	12,079,975	12,321,574	12,668,006	12,819,366	13,075,753	13,337,268
D VARIABLE O&M REVENUE											
Base Capacity MW		420	420	420	420	420	420	420	420	420	420
Total Cummulative Operting Hours		4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680
Variable O&M Payment ($4.410/mw.h)		$5.593	$5.705	$5.819	$5.935	$6.054	$6.175	$6.298	$6.424	$6.553	$6.684
Escalates with General Inflation											
Total Variable O&M Revenue		11,005,666	11,225,779	11,450,296	11,679,301	11,912,887	12,151,144	12,394,167	12,642,051	12,894,892	13,152,789
E. HEAT RATE BENEFIT											
Heat Rate Benefit*	300.00	2,499,987	2,544,909	2,590,731	2,637,469	2,685,140	2,733,766	2,703,364	2,833,935	2,885,567	2,938,191
*300 plus /kwhr*op hrs*kw/1000*gas **price**											
F. FUEL PAYMENT (Pass Through)		61,309,560	62,411,242	63,534,957	64,681,147	65,850,261	67,042,757	68,259,103	69,499,776	70,765,262	72,056,058
G. START-UP BONUS											
START-UP REVENUE FACTOR											
# - On Time Starts		0	0	0	0	0	0	0	0	0	0
$ 20,000/On Time Start		25,365	25,872	26,390	26,917	27,456	28,005	28,565	29,136	29,719	30,313
START-UP BONUS		0	0	0	0	0	0	0	0	0	0
H. AVAILABILITY BONUS											
Bonus Factor ($1,000,000/% **avail.>90%)**		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Bonus Factor Earned		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Availability Bonus		0	0	0	0	0	0	0	0	0	0

P1134
[illegible]

PROJECT: SPRIN--- N
FINANCIAL PROJECTIC
2x1 CONFIGURATION
TOTAL PROJECT COST $395,412,041

ASSUMPTIONS EXPENSES

	11	12	13	14	15
	2015	2016	2017	2018	2019
A. FUEL					
1. FUEL CONSUMPTION					
Base Heat Rate 7159 Btu/kw.h(HHV)	7,159	7,159	7,159	7,159	7,159
KWH Produced (000's)	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846
Fuel Usage-Before Start-Up Gas (000's mmBtu (HHV))	14,088	14,088	14,088	14,088	14,088
Start-Up Gas (Hot Start) 750mmbtu's/turbine/	380	390	390	390	390
TOTAL GAS USED IN OPERATIONS	14,478	14,478	14,478	14,478	14,478
2. FUEL COST PER UNIT					
Rate $/mmBtu (HHV) $3.00	3.805	3.881	3.958	4.038	4.118
Transportation $/mmBtu (HHV)	0.430	0.430	0.430	0.430	0.430
TOTAL FUEL PRICE	4.235	4.311	4.388	4.468	4.548
TOTAL FUEL EXPENSE	61,309,560	62,411,242	63,534,957	64,681,147	65,860,261
B. VARIABLE COSTS					
Chemical Lubricant & Ammonia Cost ($/Mwh)	0.2611	0.2663	0.2717	0.2771	0.2826
Contingency ($/Mwh)	0.3981	0.4061	0.4142	0.4225	0.4309
C. FIXED COSTS					
Property and Other Taxes 1.1600%	3,198,046	3,262,007	3,327,247	3,393,792	3,461,668
O&M Labor	2,060,893	2,102,111	2,144,153	2,187,036	2,230,777
Compliance & Professional Fees	31,706	32,340	32,987	33,647	34,320
General & Administrative (GP)	951,181	970,205	989,609	1,009,401	1,029,589
Operator Fee	380,473	388,082	395,844	403,761	411,836
Operator Bonus	887,769	905,525	923,635	942,108	960,950
Management Fee (GP)	317,060	323,402	329,870	336,467	343,196
Insurance	2,282,835	2,328,492	2,375,062	2,422,563	2,471,014
Contingency	634,121	646,803	659,739	672,934	686,393

	16	17	18	19	20
	2020	2021	2022	2023	2024
A. FUEL					
1. FUEL CONSUMPTION					
Base Heat Rate 7159 Btu/kw.h(HHV)	7,159	7,159	7,159	7,159	7,159
KWH Produced (000's)	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846
Fuel Usage-Before Start-Up Gas (000's mmBtu (HHV))	14,088	14,088	14,088	14,088	14,088
Start-Up Gas (Hot Start) 750mmbtu's/turbine/	390	390	390	390	390
TOTAL GAS USED IN OPERATIONS	14,478	14,478	14,478	14,478	14,478
2. FUEL COST PER UNIT					
Rate $/mmBtu (HHV) $3.00	4.201	4.285	4.370	4.458	4.547
Transportation $/mmBtu (HHV)	0.430	0.430	0.430	0.430	0.430
TOTAL FUEL PRICE	4.631	4.715	4.800	4.888	4.977
TOTAL FUEL EXPENSE	67,042,757	68,259,103	69,499,776	70,765,262	72,056,058
B. VARIABLE COSTS					
Chemical Lubricant & Ammonia Cost ($/Mwh)	0.2883	0.2941	0.2999	0.3059	0.3120
Contingency ($/Mwh)	0.4396	0.4484	0.4573	0.4665	0.4758
C. FIXED COSTS					
Property and Other Taxes 1.1600%	3,530,901	3,601,519	3,673,549	3,747,020	3,821,961
O&M Labor	2,275,392	2,320,900	2,367,318	2,414,665	2,462,958
Compliance & Professional Fees	35,006	35,706	36,420	37,149	37,892
General & Administrative (GP)	1,050,181	1,071,185	1,092,608	1,114,461	1,136,750
Operator Fee	420,072	428,474	437,043	445,784	454,700
Operator Bonus	980,169	999,772	1,019,768	1,040,163	1,060,966
Management Fee (GP)	350,060	357,062	364,203	371,487	378,917
Insurance	2,520,435	2,570,843	2,622,260	2,674,705	2,728,189
Contingency	700,121	714,123	728,406	742,974	757,833

P1135 6059

PROJECT: SPRING I 'N
FINANCIAL PROJECTI\
2x1 CONFIGURATION
TOTAL PROJECT COST 4336,442,641

4/2/03

		11	12	13	14	15	16	17	18	19	20
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
D. VARIABLE O&M RESERVE											
ANNUAL OVERHAUL RESERVES											
GT Insp/OH Reserve	$806	7,929,574	8,088,166	8,249,929	8,414,928	8,583,226	8,754,891	8,929,989	9,108,688	9,290,760	9,476,575
$668/hr /turbine x 2		0	0	0	0	0	0	0	0	0	0
ST Insp/OH Reserve	$167	953,898	972,976	992,436	1,012,284	1,032,630	1,053,181	1,074,244	1,095,729	1,117,644	1,139,997
$ 9 million /56,000 hrs											
SCR Replacement Reserve	$173	989,229	1,009,013	1,029,193	1,049,777	1,070,773	1,092,188	1,114,032	1,136,313	1,159,039	1,182,220
$6 million /38,000 hrs											
Misc. Contingency	0.2843	633,905	646,583	659,516	672,706	686,159	699,883	713,880	728,168	742,721	757,575
$0.2540 /Mwh											
ANNUAL RESERVE ACTIVITY											
GAS TURBINE											
Beginning Balance		37,375,727	7,929,574	16,017,740	24,267,669	32,682,597	41,265,823	8,754,891	17,684,879	26,793,468	36,084,228
Annual Accrual		7,929,674	8,088,166	8,249,929	8,414,928	8,583,226	8,754,891	8,929,989	9,108,688	9,290,760	9,476,575
Reserves Used		(37,375,727)					(41,265,823)				
Ending Balance		7,929,574	16,017,740	24,267,669	32,682,597	41,265,823	8,754,891	17,684,879	26,793,468	36,084,228	45,560,803
STEAM TURBINE											
Beginning Balance		8,568,472	953,898	1,926,874	2,919,310	3,931,594	4,984,124	6,017,305	7,091,549	8,187,279	9,304,922
Annual Accrual		953,898	972,976	992,436	1,012,284	1,032,630	1,053,181	1,074,244	1,095,729	1,117,644	1,139,997
Reserves Used		(8,568,472)									
Ending Balance		953,898	1,926,874	2,919,310	3,931,594	4,984,124	6,017,305	7,091,549	8,187,279	9,304,922	10,444,919
SCR											
Beginning Balance		2,852,820	3,842,048	4,851,062	5,880,255	6,930,032	1,070,773	2,162,961	3,276,993	4,413,306	5,572,345
Annual Accrual		989,229	1,009,013	1,029,193	1,049,777	1,070,773	1,092,188	1,114,032	1,136,313	1,159,039	1,182,220
Reserves Used						(6,930,032)					
Ending Balance		3,842,048	4,851,062	5,880,255	6,930,032	1,070,773	2,162,961	3,276,993	4,413,306	5,572,346	6,754,565
MISC CONTIGENCY											
Beginning Balance		1,230,766	633,905	1,280,489	659,516	1,332,220	686,159	1,386,042	713,880	1,442,038	742,721
Annual Accrual		633,905	646,583	659,516	672,706	686,159	699,883	713,880	728,158	742,721	757,575
Reserves Used		(1,230,766)		(1,280,489)		(1,332,220)		(1,386,042)		(1,442,038)	
Ending Balance		633,905	1,280,489	659,515	1,332,220	686,159	1,386,042	713,880	1,442,038	742,721	1,500,296
TOTAL OVERHAUL RESERVE											
Beginning Balance		50,027,784	13,359,426	24,076,165	33,726,749	44,876,444	47,986,880	18,321,199	28,767,302	40,836,090	51,704,216
Annual Accrual		10,506,606	10,716,738	10,931,073	11,149,695	11,372,689	11,600,142	11,832,145	12,068,788	12,310,164	12,556,367
Reserves Used		(47,174,965)	0	(1,280,489)	0	(8,262,253)	(41,265,823)	(1,386,042)	0	(1,442,038)	0
Ending Balance		13,359,426	24,076,165	33,726,749	44,876,444	47,986,880	18,321,199	28,767,302	40,836,090	51,704,218	64,260,583
DEBT RESERVE (FROM BELOW)		0	0	0	0	0	0	0	0	0	0
WORKING CAP RESERVE (BELOW)		0	0	0	0	0	0	0	0	0	0
TOTAL RESERVE FUNDS		13,359,427	24,076,166	33,726,750	44,876,445	47,986,881	18,321,200	28,767,304	40,836,092	51,704,217	64,260,585
INTEREST INCOME	1.50%	475,404	280,767	433,522	589,524	696,476	497,311	353,164	522,025	694,052	869,736
ESCALATION FACTORS											
GAS ESCALATION		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
GENERAL INFLATION		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
PROPERTY TAXES		1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%

		11	12	13	14	15	16	17	18	19	20
PROJECT: SPRING ( )N											
FINANCIAL PROJECTI.											
2x1 CONFIGURATION											
TOTAL PROJECT COST	$330,442,041	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
INCOME AND CASHFLOW STATEMENT											
ELECTRIC REVENUE:											
Capacity Sales		40,366,080	40,366,080	40,366,080	40,366,080	40,366,080	40,366,080	40,366,080	40,366,080	40,366,080	40,366,080
Fixed O&M Revenue		11,160,029	11,383,230	11,610,894	11,843,112	12,079,975	12,321,574	12,568,006	12,819,366	13,075,753	13,337,268
Variable O&M Revenue		11,005,666	11,225,779	11,450,295	11,679,301	11,912,887	12,151,144	12,394,167	12,642,051	12,894,892	13,152,789
Heat Rate Benefit		2,499,987	2,544,909	2,590,731	2,637,468	2,685,140	2,733,766	2,783,364	2,833,955	2,885,557	2,938,191
Fuel Payment		61,309,560	62,411,242	63,534,957	64,681,147	65,850,261	67,042,757	68,259,103	69,499,776	70,765,262	72,056,058
Availability Bonus Payment		0	0	0	0	0	0	0	0	0	0
Startup Payment		0	0	0	0	0	0	0	0	0	0
		126,341,321	127,931,240	129,552,957	131,207,108	132,894,343	134,615,322	136,370,720	138,161,227	139,987,544	141,850,387
INTEREST REVENUE		475,404	280,767	433,522	589,524	696,475	497,311	353,164	522,025	694,052	869,736
TOTAL REVENUE		126,816,726	128,212,007	129,986,479	131,796,632	133,590,818	135,112,632	136,723,884	138,683,252	140,681,596	142,720,123
OPERATING EXPENSES											
Fuel Costs		61,309,560	62,411,242	63,534,957	64,681,147	65,850,261	67,042,757	68,259,103	69,499,776	70,765,262	72,056,058
Property and Other Taxes		3,198,046	3,262,007	3,327,247	3,393,792	3,461,668	3,530,901	3,601,519	3,673,549	3,747,020	3,821,961
O&M Labor		2,060,893	2,102,111	2,144,153	2,187,036	2,230,777	2,275,392	2,320,900	2,367,318	2,414,665	2,462,958
Compliance & Professional Fees		31,706	32,340	32,987	33,647	34,320	35,006	35,706	36,420	37,149	37,892
General & Administrative		951,181	970,205	989,609	1,009,401	1,029,589	1,050,181	1,071,185	1,092,608	1,114,461	1,136,750
Operator Fee		380,473	388,082	395,844	403,761	411,836	420,072	428,474	437,043	445,784	454,700
Operator Bonus		887,769	905,525	923,635	942,108	960,950	980,169	999,772	1,019,768	1,040,163	1,060,966
Management Fee		317,060	323,402	329,870	336,467	343,196	350,060	357,062	364,203	371,487	378,917
Insurance		2,282,835	2,328,492	2,376,062	2,422,683	2,471,014	2,520,435	2,570,843	2,622,260	2,674,705	2,728,199
Chem, Lubricant&Ammonia		513,822	524,098	534,580	545,272	556,177	567,301	578,647	590,220	602,024	614,064
Contingency		634,121	646,803	659,739	672,934	686,393	700,121	714,123	728,406	742,974	757,833
		72,567,466	73,894,306	75,247,683	76,628,127	78,036,181	79,472,395	80,937,334	82,431,671	83,955,693	85,510,298
OPERATING CASHFLOW		54,249,260	54,317,701	54,738,798	55,168,505	55,654,637	55,640,237	55,786,550	56,251,581	56,725,902	57,209,824
DEBT SERVICE REQUIREMENTS											
Principal Payment on Debt		11,237,270	12,106,961	13,035,896	14,040,663	15,128,370	16,294,278	17,547,866	18,900,983	20,363,108	21,934,240
Interest Payment		11,524,318	10,641,134	9,690,012	8,665,666	7,562,052	6,373,306	5,092,984	3,714,066	2,228,556	628,409
		22,761,588	22,748,095	22,726,908	22,706,329	22,690,422	22,667,583	22,640,850	22,615,049	22,591,663	22,562,649
CASHFLOW BEFORE OTHER ITEMS		31,487,672	31,569,606	32,012,888	32,462,177	32,864,215	32,972,654	33,145,701	33,636,632	34,134,239	34,647,176
OTHER ITEMS:											
Fees Payment		0	0	0	0	0	0	0	0	0	0
Contribution to Reserves		(10,506,606)	(10,716,738)	(10,931,073)	(11,149,695)	(11,372,689)	(11,600,142)	(11,832,145)	(12,068,788)	(12,310,164)	(12,556,367)
Working Capital/other		0	0	0	0	0	0	0	0	0	0
		(10,506,606)	(10,716,738)	(10,931,073)	(11,149,695)	(11,372,689)	(11,600,142)	(11,832,145)	(12,068,788)	(12,310,164)	(12,556,367)
DEBT RESERVE										0	
Release of Debt Reserve											
Refinancing Proceeds											
DISTRIBUTABLE CASHFLOW		20,981,066	20,852,868	21,081,814	21,312,482	21,491,527	21,372,512	21,313,555	21,567,844	21,824,075	22,090,809
EQUITY AMOUNT INVESTED:	$ (118,468,832)	20,981,066	20,852,868	21,081,814	21,312,482	21,491,527	21,372,512	21,313,555	21,567,844	21,824,075	22,090,809
Pre-Tax IRR of Equity (20 years)											
OUTSIDE											
USA Power											

4/2/03

P1137

4/2/03

		11	12	13	14	15	16	17	18	19	20
PROJECT: SPRING (											
FINANCIAL PROJECTIO.											
2x1 CONFIGURATION											
TOTAL PROJECT COST	$355,442,041	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
TOTAL PROJECT COST	$355,442,041										
EQUITY INVESTED	33.33%										
DISCOUNT RATE	1.16	3,534,530	3,028,391	2,639,345	2,300,193	1,999,683	1,714,233	1,473,710	1,285,697	1,121,440	978,574
PRESENT VALUE		97,322,517	100,350,908	102,990,253	105,290,446	107,290,029	109,004,261	110,477,971	111,763,669	112,885,009	113,863,583
NET PRESENT VALUE		-21,146,315	-18,117,924	-15,478,579	-13,178,387	-11,178,803	-9,464,571	-7,990,861	-6,705,263	-5,583,823	-4,605,249
SENIOR DEBT SERVICE											
INTEREST RATES											
Libor Swap Assumption											
Interest Rate Spreads											
Effective Years											
AMORTIZATION SCHEDULE	**Tranche A**										
QRTR #1 Percentage Amortization		1.15%	1.24%	1.34%	1.44%	1.55%	1.67%	1.80%	1.94%	2.09%	2.25%
QRTR #2 Percentage Amortization		1.17%	1.27%	1.36%	1.47%	1.58%	1.70%	1.83%	1.98%	2.13%	2.29%
QRTR #3 Percentage Amortization		1.20%	1.29%	1.39%	1.50%	1.61%	1.74%	1.87%	2.01%	2.17%	2.34%
QRTR #4 Percentage Amortization		1.22%	1.31%	1.41%	1.52%	1.64%	1.77%	1.90%	2.05%	2.21%	2.38%
Total		4.74%	5.11%	5.50%	5.93%	6.38%	6.88%	7.41%	7.98%	8.59%	9.26%
PRINCIPAL PAYMENTS											
QRTR #1 Principal	Tranche A	2,732,301	2,943,207	3,168,332	3,412,414	3,677,824	3,959,822	4,265,518	4,594,911	4,950,370	5,331,897
QRTR #2 Principal	Tranche A	2,782,065	2,997,711	3,227,575	3,476,397	3,746,646	4,036,654	4,346,089	4,680,221	5,042,790	5,431,426
QRTR #3 Principal	Tranche A	2,834,200	3,054,585	3,289,188	3,542,749	3,815,269	4,111,485	4,426,860	4,767,901	5,137,579	5,533,324
QRTR #4 Principal	Tranche A	2,888,703	3,111,458	3,350,801	3,609,102	3,888,730	4,187,317	4,509,600	4,857,951	5,232,368	5,637,593
Total Principal		11,237,270	12,106,961	13,035,896	14,040,683	15,128,370	16,294,278	17,547,866	18,900,983	20,363,108	21,934,240
Period Beginning Balance	66.67%	160,615,701	149,378,432	137,271,470	124,235,574	110,194,912	95,066,542	78,772,264	61,224,398	42,323,415	21,960,307
Payments		11,237,270	12,106,961	13,035,896	14,040,663	15,128,370	16,294,278	17,547,866	18,900,983	20,363,108	21,934,240
Period Ending Balance		149,378,432	137,271,470	124,235,574	110,194,912	95,066,542	78,772,264	61,224,398	42,323,415	21,960,307	26,067
PRINCIPAL PAYMENTS											
Tranch A											
QRTR #1 Principal		2,732,301	2,943,207	3,168,332	3,412,414	3,677,824	3,959,822	4,265,518	4,594,911	4,950,370	5,331,897
QRTR #2 Principal		2,782,065	2,997,711	3,227,576	3,476,397	3,746,646	4,035,654	4,346,089	4,680,221	5,042,790	5,431,426
QRTR #3 Principal		2,834,200	3,054,585	3,289,188	3,542,749	3,815,269	4,111,485	4,426,660	4,767,901	5,137,579	5,533,324
QRTR #4 Principal		2,888,703	3,111,458	3,350,801	3,609,102	3,888,730	4,187,317	4,509,600	4,857,951	5,232,368	5,637,593
Total Principal		11,237,270	12,106,961	13,035,896	14,040,683	15,128,370	16,294,278	17,547,866	18,900,983	20,363,108	21,934,240
Period Beginning Balance		160,616,701	149,378,432	137,271,470	124,235,574	110,194,912	95,068,542	78,772,264	61,224,398	42,323,415	21,960,307
Payments		11,237,270	12,108,961	13,035,898	14,040,683	15,128,370	16,294,278	17,547,866	18,900,983	20,383,108	21,934,240
Period Ending Balance		149,378,432	137,271,470	124,235,574	110,194,912	95,068,542	78,772,284	61,224,398	42,323,416	21,960,307	26,067
INTEREST PAYMENTS		11	12	13	14	15	16	17	18	19	20
Interest Rate on Debt (swap amount)		6.25%	6.25%	6.26%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%	6.25%
Spread		1.250%	1.250%	1.250%	1.250%	1.250%	1.250%	1.250%	1.250%	1.250%	1.250%
All-in Rate		7.50%	7.50%	7.60%	7.50%	7.60%	7.50%	7.60%	7.50%	7.50%	7.50%
QRTR #1 Interest		2,960,314	2,745,660	2,514,434	2,265,434	1,997,195	1,708,261	1,397,001	1,061,803	700,745	311,783
QRTR #2 Interest		2,908,150	2,689,463	2,453,917	2,200,252	1,926,948	1,632,682	1,315,512	974,049	606,192	209,843
QRTR #3 Interest		2,855,009	2,632,180	2,392,245	2,133,825	1,855,411	1,556,492	1,232,512	884,651	509,863	108,194
QRTR #4 Interest		2,800,846	2,573,840	2,329,417	2,066,155	1,782,498	1,476,980	1,147,957	793,564	411,756	489
Total Interest		11,524,318	10,641,134	9,690,012	8,665,666	7,562,052	6,373,306	5,092,984	3,714,066	2,228,555	628,409
Annual Admin		-	-	-	-	-	-	-	-	-	-
LOC Fee Payment		0	0	0	0	0	0	0	0	0	0
Total Interest and **Fees**		11,524,318	10,641,134	9,690,012	8,665,666	7,562,052	6,373,306	5,092,984	3,714,066	2,228,555	628,409
DEBT RESERVE											
Beginning		0	0	0	0	0	0	0	0	0	0
Addition		0	0	0	0	0	0	0	0	0	0
Ending		0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio		2.383	2.388	2.409	2.430	2.448	2.455	2.464	2.487	2.511	2.536
WORKING CAPITAL RESERVE											
Beginning		0	0	0	0	0	0	0	0	0	0
Addition to working capital		0	0	0	0 4/2/03	0	0	0	0	0	0
Ending		0	0	0	0	0	0	0	0	0	0

P1138

PROJECT: SPRING I N
FINANCIAL PROJECTIL
2x1 CONFIGURATION
TOTAL PROJECT COST $388,442,041

		21	22	23	24	25	26	27	28	29	30
		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSUMPTIONS-REVENUE											
A. ELECTRIC ENERGY REVENUE											
1. MW BASE CAPACITY		420	420	420	420	420	420	420	420	420	420
MW PEAKING CAPACITY	**100%**	539	539	539	539	539	539	539	539	539	539
2. ANNUAL OPERATING HOURS											
18 hr/d,6d/wk,52 wkp/yr		4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680
		0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0
Total Operating Hours		4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680
Cumulative Equivalent Operating **Hours**		102,713	107,393	112,073	116,753	121,433	126,113	130,793	135,473	140,153	144,833
3. KWH SOLD 000's											
KWH		1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846
		0	0	0	0	0	0	0	0	0	0
Total kWh Sold		1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846

P1139
10003

ROJECT: SPRING (N
HANCIAL PROJECTIC
(I CONFIGURATION
OTAL PROJECT COST $355,442,041

		21	22	23	24	25	26	27	28	29	30
		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
B. CAPACITY REVENUE											
Base Capacity MW		420	420	420	420	420	420	420	420	420	420
Capacity Payment	$kw/yr	$96.00	$96.00	$96.00	$96.00	$96.00	$96.00	$96.00	$96.00	$96.00	$96.00
		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Capacity Revenue		40,366,080	40,366,080	40,366,080	40,366,080	40,366,080	40,366,080	40,366,080	40,366,080	40,366,080	40,366,080
C. FIXED O&M REVENUE											
Base Capacity MW		420	420	420	420	420	420	420	420	420	420
Fixed O&M Payment ($20.928/kw.yr)		$32.354	$33.001	$33.661	$34.334	$35.021	$35.721	$36.435	$37.164	$37.907	$38.665
Escalates with General Inflation											
Total Fixed O&M Revenue		13,604,013	13,876,094	14,153,616	14,436,688	14,725,422	15,019,930	15,320,329	15,626,735	15,939,270	16,258,055
D. VARIABLE O&M REVENUE											
Base Capacity MW		420	420	420	420	420	420	420	420	420	420
Total Cummulative Operting Hours		4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680
Variable O&M Payment ($4.410/mw.h)		$6.818	$6.954	$7.093	$7.235	$7.380	$7.527	$7.678	$7.831	$7.988	$8.148
Escalates with General Inflation											
Total Variable O&M Revenue		13,415,645	13,684,162	13,957,845	14,237,002	14,521,742	14,812,177	15,108,421	15,410,589	15,718,801	16,033,177
E. HEAT RATE BENEFIT											
Heat Rate Benefit*	300.00	2,991,870	3,046,628	3,102,494	3,169,467	3,217,579	3,276,854	3,337,314	3,396,983	3,461,886	3,526,046
*300 btus /kwhr*op hrs*kw/1000*gas price											
F. FUEL PAYMENT (Pass Through)		73,372,670	74,715,614	76,085,417	77,482,617	78,907,760	80,361,406	81,844,125	83,356,498	84,899,119	86,472,592
G. START-UP BONUS											
START-UP REVENUE FACTOR											
# On Time Starts		0	0	0	0	0	0	0	0	0	0
$ 20,000/On Time Start		30,920	31,538	32,169	32,812	33,468	34,138	34,820	35,517	36,227	36,952
START-UP BONUS		0	0	0	0	0	0	0	0	0	0
H. AVAILABILITY BONUS											
Bonus Factor ($1,000,000/% avail.>90%)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Bonus Factor Earned		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Availability Bonus		0	0	0	0	0	0	0	0	0	0

P1140
16,804

PROJECT: SPRING ' ON
FINANCIAL PROJECTI
2x1 CONFIGURATION
TOTAL PROJECT COST $388,442,041

		21	22	23	24	25	26	27	28	29	30
		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSUMPTIONS EXPENSES											
A. FUEL											
1. FUEL CONSUMPTION											
Base Heat Rate 7159 Btu/kw.h(HHV)		7,159	7,159	7,159	7,159	7,159	7,159	7,159	7,159	7,159	7,159
KWH Produced (000's)		1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846
Fuel Usage-Before Start-Up Gas (000's mmBtu (HHV))		14,088	14,088	14,088	14,088	14,088	14,088	14,088	14,088	14,088	14,088
Start-Up Gas (Hot Start)	760mmbtu's/turbine/s	390	390	390	390	390	390	390	390	390	390
TOTAL GAS USED IN OPERATIONS		14,478	14,478	14,478	14,478	14,478	14,478	14,478	14,478	14,478	14,478
2. FUEL COST PER UNIT											
Rate $/mmBtu (HHV) $3.00		4.638	4.731	4.825	4.922	5.020	5.121	5.223	5.328	5.434	5.543
Transportation $/mmBtu (HHV)		0.430	0.430	0.430	0.430	0.430	C.430	0.430	0.430	0.430	0.430
TOTAL FUEL PRICE		5.068	5.161	5.255	5.352	5.450	5.551	5.653	5.758	5.864	5.973
TOTAL FUEL EXPENSE		73,372,670	74,715,614	76,085,417	77,482,617	78,907,760	80,361,408	81,844,125	83,356,498	84,899,119	86,472,592
B. VARIABLE COSTS											
Chemical Lubricant & Ammonia **Cost ($/Mwh)**		0.3183	0.3247	0.3311	0.3378	0.3445	0.3514	0.3584	0.3656	0.3729	0.3804
Contingency ($/Mwh)		0.4853	0.4950	0.5049	0.5150	0.5253	0.5358	0.5465	0.5575	0.5686	0.5800
C. FIXED COSTS											
Property and Other Taxes	**1.1600%**	3,898,400	3,976,368	4,055,895	4,137,013	4,219,754	4,304,149	4,390,232	4,478,036	4,567,597	4,658,949
O&M Labor		2,512,217	2,562,461	2,613,711	2,665,985	2,719,304	2,773,691	2,829,164	2,885,748	2,943,463	3,002,332
Compliance & Professional Fees		38,649	39,422	40,211	41,015	41,835	42,672	43,526	44,396	45,284	46,190
General & Administrative (GP)		1,159,485	1,182,674	1,206,328	1,230,454	1,255,064	1,280,165	1,305,768	1,331,884	1,358,521	1,385,692
Operator Fee		463,794	473,070	482,531	492,182	502,025	512,066	522,307	532,753	543,408	554,277
Operator Bonus		1,082,186	1,103,829	1,125,906	1,148,424	1,171,393	1,194,821	1,218,717	1,243,091	1,267,953	1,293,312
Management Fee (GP)		386,495	394,225	402,109	410,151	418,355	426,722	435,256	443,961	452,840	461,897
Insurance		2,782,763	2,838,419	2,895,187	2,953,091	3,012,153	3,072,396	3,133,844	3,196,520	3,260,451	3,325,660
Contingency		772,990	788,450	804,219	820,303	836,709	853,443	870,512	887,922	905,681	923,794

OJECT: SPRING (N
IANCIAL PROJECTIL
I CONFIGURATION
'TAL PROJECT COST $386,442,041

		21	22	23	24	25	26	27	28	29	30
		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
D. VARIABLE O&M RESERVE											
ANNUAL OVERHAUL RESERVES											
GT Insp/OH Reserve	$895	9,666,107	9,859,429	10,056,618	10,257,750	10,462,905	10,672,163	10,885,606	11,103,318	11,325,385	11,551,892
$668/hr /turbine x 2		0	0	0	0	0	0	0	0	0	0
ST Insp/OH Reserve	$187	1,162,797	1,186,053	1,209,774	1,233,969	1,258,648	1,283,821	1,309,498	1,335,688	1,362,402	1,389,650
$ 9 million /56,000 hrs											
SCR Replacement Reserve	$173	1,205,864	1,229,981	1,254,581	1,279,673	1,305,266	1,331,371	1,357,999	1,385,159	1,412,862	1,441,119
$6 million /36,000 hrs											
Misc. Contingency	0.2843	772,727	788,181	803,945	820,024	836,425	853,153	870,216	887,620	905,373	923,480
$0.2640 /Mwh											
ANNUAL RESERVE ACTIVITY											
GAS TURBINE											
Beginning Balance		45,560,803	9,666,107	19,525,536	29,582,153	39,839,903	50,302,808	10,672,163	21,557,769	32,661,088	43,986,472
Annual Accrual		9,666,107	9,859,429	10,056,618	10,257,750	10,462,905	10,672,163	10,885,606	11,103,318	11,325,385	11,551,892
Reserves Used		(45,560,803)					(50,302,808)				(43,986,472)
Ending Balance		9,666,107	19,525,536	29,582,153	39,839,903	50,302,808	10,672,163	21,557,769	32,661,088	43,986,472	11,551,892
STEAM TURBINE											
Beginning Balance		10,444,919	1,162,797	2,348,849	3,558,623	4,792,592	6,051,240	7,335,061	8,644,559	9,980,247	11,342,649
Annual Accrual		1,162,797	1,186,053	1,209,774	1,233,969	1,258,648	1,283,821	1,309,498	1,335,688	1,362,402	1,389,650
Reserves Used		(10,444,919)									(11,342,649)
Ending Balance		1,162,797	2,348,849	3,558,623	4,792,592	6,051,240	7,335,061	8,644,559	9,980,247	11,342,649	1,389,650
SCR											
Beginning Balance		6,754,565	7,960,429	1,229,981	2,484,562	3,764,235	5,069,501	6,400,873	7,758,872	9,144,030	1,412,862
Annual Accrual		1,205,864	1,229,981	1,254,581	1,279,673	1,305,266	1,331,371	1,357,999	1,385,159	1,412,862	1,441,119
Reserves Used			(7,960,429)							(9,144,030)	
Ending Balance		7,960,429	1,229,981	2,484,562	3,764,235	5,069,501	6,400,873	7,758,872	9,144,030	1,412,862	2,853,981
MISC CONTIGENCY											
Beginning Balance		1,500,296	772,727	1,560,908	803,945	1,623,969	836,425	1,689,578	870,216	1,757,836	905,373
Annual Accrual		772,727	788,181	803,945	820,024	836,425	853,153	870,216	887,620	905,373	923,480
Reserves Used		(1,500,296)		(1,560,908)		(1,623,969)		(1,689,578)		(1,757,836)	
Ending Balance		772,727	1,560,908	803,945	1,623,969	836,425	1,689,578	870,216	1,757,836	905,373	1,828,853
TOTAL OVERHAUL RESERVE											
Beginning Balance		64,260,583	19,562,059	24,665,275	36,429,284	50,020,699	62,259,974	26,097,675	38,831,416	53,543,202	57,647,356
Annual Accrual		12,807,495	13,063,644	13,324,917	13,591,416	13,863,244	14,140,509	14,423,319	14,711,785	15,006,021	15,306,142
Reserves Used		(57,506,019)	(7,960,429)	(1,560,908)	0	(1,623,969)	(50,302,808)	(1,689,578)	0	(10,901,867)	(55,329,121)
Ending Balance		19,562,059	24,665,275	36,429,284	50,020,699	62,259,974	26,097,675	38,831,416	53,543,202	57,647,356	17,624,376
DEBT RESERVE (FROM BELOW)		0	0	0	0	0	0	0	0	0	0
WORKING CAP RESERVE (BELOW)		0	0	0	0	0	0	0	0	0	0
TOTAL RESERVE FUNDS		19,562,060	24,665,276	36,429,285	50,020,701	62,259,975	26,097,676	38,831,418	53,543,203	57,647,357	17,624,378
INTEREST INCOME	1.50%	628,670	331,705	458,209	648,375	842,105	662,682	486,968	692,810	833,929	564,536
ESCALATION FACTORS											
GAS ESCALATION		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
GENERAL INFLATION		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
PROPERTY TAXES		1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%

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ROJECT: SPRING ' 'N
INANCIAL PROJECTI
‹1 CONFIGURATION
OTAL PROJECT COST $365,142,041

		21	22	23	24	25	26	27	28	29	30
		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
'NCOME AND CASHFLOW STATEMENT											
:LECTRIC REVENUE:											
Capacity Sales		40,366,080	40,366,080	40,366,080	40,368,080	40,366,080	40,366,080	40,366,080	40,368,080	40,366,080	40,366,080
Fixed O&M Revenue		13,604,013	13,876,094	14,153,616	14,436,688	14,725,422	15,019,930	15,320,329	15,626,735	15,939,270	16,258,055
Variable O&M Revenue		13,415,845	13,684,162	13,957,845	14,237,002	14,521,742	14,812,177	15,108,421	15,410,589	15,718,801	16,033,177
Heat Rate Benefit		2,991,878	3,046,638	3,102,494	3,159,467	3,217,579	3,276,854	3,337,314	3,398,983	3,461,885	3,526,046
Fuel Payment		73,372,670	74,715,614	76,085,417	77,482,617	78,907,760	80,361,406	81,844,125	83,356,498	84,899,119	86,472,592
Availability Bonus Payment		0	0	0	0	0	0	0	0	0	0
Startup Payment		0	0	0	0	0	0	0	0	0	0
		143,750,487	145,688,588	147,665,452	149,681,854	151,738,583	153,836,447	155,976,268	158,158,885	160,385,155	162,655,950
INTEREST REVENUE		628,670	331,705	458,209	648,375	842,105	662,682	486,968	692,810	833,929	564,538
TOTAL REVENUE		144,379,156	146,020,293	148,123,662	150,330,228	152,580,688	154,499,129	156,463,236	158,851,696	161,219,084	163,220,488
OPERATING EXPENSES											
Fuel Costs		73,372,670	74,715,614	76,085,417	77,482,617	78,907,760	80,361,406	81,844,126	83,356,498	84,899,119	86,472,592
Property and Other Taxes		3,898,400	3,976,368	4,055,895	4,137,013	4,219,764	4,304,149	4,390,232	4,478,036	4,567,597	4,658,949
O&M Labor		2,512,217	2,562,461	2,613,711	2,665,985	2,719,304	2,773,691	2,829,164	2,885,748	2,943,463	3,002,332
Compliance & Professional Fees		38,649	39,422	40,211	41,015	41,835	42,672	43,526	44,396	45,284	46,190
General & Administrative		1,159,485	1,182,674	1,206,328	1,230,454	1,255,064	1,280,165	1,305,768	1,331,884	1,358,521	1,385,692
Operator Fee		463,794	473,070	482,531	492,182	502,025	512,066	522,307	532,753	543,408	554,277
Operator Bonus		1,082,186	1,103,829	1,125,906	1,148,424	1,171,393	1,194,821	1,218,717	1,243,091	1,267,953	1,293,312
Management Fee		386,495	394,225	402,109	410,151	418,355	426,722	435,256	443,961	452,840	461,897
Insurance		2,782,763	2,838,419	2,895,187	2,953,091	3,012,153	3,072,396	3,133,844	3,196,520	3,260,451	3,325,660
Chem, Lubricant&Ammonia		626,346	638,873	651,650	664,683	677,977	691,536	705,367	719,474	733,864	748,541
Contingency		772,990	788,450	804,219	820,303	836,709	853,443	870,512	887,922	905,681	923,794
		87,095,995	88,713,406	90,363,165	92,045,918	93,762,328	95,513,065	97,298,817	99,120,284	100,978,181	102,873,235
OPERATING CASHFLOW		57,283,161	57,306,888	57,760,497	58,284,310	58,818,360	58,986,064	59,164,419	59,731,410	60,240,903	60,347,253
DEBT SERVICE REQUIREMENTS											
Principal Payment on Debt		0	0	0	0	0	0	0	0	0	0
Interest Payment		0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0
CASHFLOW BEFORE OTHER ITEMS		57,283,161	57,306,888	57,760,497	58,284,310	58,818,360	58,986,064	59,164,419	59,731,410	60,240,903	60,347,253
OTHER ITEMS:											
Fees Payment		0	0	0	0	0	0	0	0	0	0
Contribution to Reserves		(12,807,495)	(13,063,644)	(13,324,917)	(13,591,416)	(13,863,244)	(14,140,509)	(14,423,319)	(14,711,785)	(15,006,021)	(15,306,142)
Working Capital/other		0	0	0	0	0	0	0	0	0	0
		(12,807,495)	(13,063,644)	(13,324,917)	(13,591,416)	(13,863,244)	(14,140,509)	(14,423,319)	(14,711,785)	(15,006,021)	(15,306,142)
DEBT RESERVE											
Release of Debt Reserve											
Refinancing Proceeds											
DISTRIBUTABLE CASHFLOW		44,475,667	44,243,243	44,435,580	44,692,894	44,955,116	44,845,555	44,741,100	45,019,625	45,234,882	45,041,112
EQUITY AMOUNT INVESTED:	$ (118,468,832)	44,475,667	44,243,243	44,435,580	44,692,894	44,955,116	44,845,555	44,741,100	45,019,625	45,234,882	45,041,112
Pre-Tax IRR of Equity (20 years)											
OUTSIDE											
USA Power											

4/2/03

P11436

.OJECT: SPRING ' N
IANCIAL PROJECTIL
1 CONFIGURATION

		21	22	23	24	25	26	27	28	29	30
)TAL PROJECT COST	$355,442,041	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
)TAL PROJECT COST	$355,442,041										
QUITY INVESTED	33.33%										
DISCOUNT RATE	1.16	1,698,426	1,456,509	1,261,070	1,093,424	948,138	816,368	701,266	608,303	526,907	524,650
PRESENT VALUE		115,562,009	117,018,619	118,279,588	119,373,013	120,321,150	121,136,518	121,837,785	122,446,088	122,972,995	123,497,644
NET PRESENT VALUE		-2,906,823	-1,460,314	-189,244	904,181	1,852,318	2,667,686	3,368,953	3,977,256	4,504,163	5,028,812
ENIOR DEBT SERVICE											
INTEREST RATES											
Libor Swap Assumption											
Interest Rate Spreads											
Effective Years											
AMORTIZATION SCHEDULE	Tranche A										
QRTR #1 Percentage Amortization											
QRTR #2 Percentage Amortization											
QRTR #3 Percentage Amortization											
QRTR #4 Percentage Amortization											
Total											
PRINCIPAL PAYMENTS											
QRTR #1 Principal	Tranche A	0									
QRTR #2 Principal	Tranche A	0									
QRTR #3 Principal	Tranche A	0									
QRTR #4 Principal	Tranche A	0									
Total Principal											
Period Beginning Balance	66.67%										
Payments											
Period Ending Balance											
PRINCIPAL PAYMENTS											
Tranch A											
QRTR #1 Principal											
QRTR #2 Principal											
QRTR #3 Principal											
QRTR #4 Principal											
Total Principal											
Period Beginning Balance											
Payments											
Period Ending Balance											
INTEREST PAYMENTS											
Interest Rate on Debt (swap amount)											
Spread											
All-in Rate											
QRTR #1 Interest											
QRTR #2 Interest											
QRTR #3 Interest											
QRTR #4 Interest											
Total Interest											
Annual Admin											
LOC Fee Payment											
Total Interest and Fees											
DEBT RESERVE											
Beginning											
Addition											
Ending											
Debt Coverage Ratio											
WORKING CAPITAL RESERVE											
Beginning											
Addition to working capital											
Ending											

4/2/03

P0144

Spring Canyon Energy LLC
Financial Assumptions

Construction Financing Assumptions

Construction Costs:		$	317,709,000
Interest rate:	5.50%		
Construction Period (6, 12, 18, 24, 30, or 36 Mo)	24		
Legal Fees:	1.00%	$	3,177,090
Total Financed during Constr:		$	320,886,090
Interest Expense during const:		$	24,002,280
Commitment Fees:	1.00%	$	2,053,671
Debt reserve (approx. 6 mo)		$	8,500,000
Amount Financed after Construction		$	355,442,041

Senior Debt Financing Assumptions

Percent of Total Financing		66.67%		
Senior Debt:			$	236,973,208
Amortization Term (Yrs)		20		
Treasury Bond (10yr)	Years 1-4	4.50%		
Spread over T-Bond	Years 1-4	3.00%		
Amort Method (Straight-line, Mortgage, Variable)				Mortgage

Equity Financing Assumptions

Equity Investment:	Total:	Outside:	USA Power:
% of Total Financing	33.33%	100.00%	0.00%
Total Equity Required:	$ 118,468,832	$118,468,832	$0
Cash Flow Allocation %		100.00%	0.00%
Pre-Tax Equity IRR	24.73%	0.00%	0.00%

Other Financing Assumptions:

Expected Financial Closing Date - Senior Debt	Dec-04
Expected Financial Closing Date - Equity	Dec-04
Initial Debt Service Reserve	$8,762,818
Interest Income Rate	2.50%

	Min.	Max.	Avg.
Debt Coverage Ratios (pre-tax)	2.55	2.84	2.73

P1146

10,07C

Spring Canyon Energy LLC
Construction Conceptual Assumptions

Plant Configuration	2x1	2(1x1)
EPC		
Civil Work, Foundation & Buildings	$5,543,990	$5,987,509
Power Island Equipment	$108,927,290	$117,641,473
Balance of Plant, Mechanical	$96,245,500	$103,948,380
Balance of Plant, Electrical & Control	$15,445,000	$16,680,600
Total Direct Cost	$226,164,780	$244,257,962
Spare Parts	$11,031,040	$11,031,040
Engineering & Construction Management	$15,831,535	$15,831,535
Contractor's Overhead & Profit	$10,576,751	$10,576,751
Logistics & Freight	$992,794	$992,794
Tax Allowance	$0	$0
Total EPC	$264,596,800	$282,690,082
Total Project Cost		
Construction Cost		
Turnkey Construction Contract (EPC)	$264,597,000	$282,690,000
Construction Contingency (7.5% of EPC Direct Cost)	$16,962,000	$18,318,000
Fuel Pipeline	$0	$0
Gas Interconnect	$250,000	$250,000
Electrical Transmission Line	$750,000	$750,000
Electrical Interconnect	$2,650,000	$2,650,000
Construction Insurance	$750,000	$750,000
Water Wells	$500,000	$500,000
Sales Tax	$0	$0
Total Construction Cost	$286,459,000	$305,908,000
Development Cost		
Land Acquisition	$250,000	$250,000
Easements & ROW	$100,000	$100,000
Water Acquisition	$2,200,000	$2,200,000
Emission Credits	$1,000,000	$1,000,000
Permitting / Legal/G&A	$2,000,000	$2,000,000
Construction Management	$2,200,000	$2,200,000
Property Tax During Construction	$2,000,000	$2,000,000
Startup	$3,000,000	$3,000,000
Initial Fuel Supply	$3,000,000	$3,000,000
Development Fee	$14,000,000	$14,000,000
Contingency	$1,500,000	$1,500,000
Total Development Cost	$31,250,000	$31,250,000
Total Project Cost	$317,709,000	$337,159,000

Notes:
Equipment Descriptions *
201= Two 7FA on one Steam Turbine
2- GE Fr7FA Turbine
1-GE Steam Turbine
1 HRSG Air Cooled

202 = Two 7FA Turbines on two Steam turbines
2- GE Fr7FA Turbines
2-GE Steam Turbines Air Cooled
HRSG

P1147
10,071

CONSTRUCTION PERIOD DRAW-DOWN SCHEDULE

Construction Period	24
Construction Loan Amount	$320,888,090
Construction Loan Rate	5.50%
Commitment Fee (%)	1.00%

No.	Month	Draw %	Principal O/S	Unused Principal	Months to Comm Oprs	Commitment Fee	IDC	Cum IDC
1.00	Jun-03	15.0%	$48,132,914	$272,753,177	24.00	$227,294	$5,294,620	$5,294,620
2.00	Jul-03	10.0%	$32,088,609	$240,664,568	23.00	$200,554	$3,382,674	$8,677,295
3.00	Aug-03	8.0%	$19,253,165	$221,411,402	22.00	$184,510	$1,941,381	$10,618,658
4.00	Sep-03	6.0%	$19,253,165	$202,158,237	21.00	$168,465	$1,853,117	$12,471,773
5.00	Oct-03	6.0%	$19,253,165	$182,905,071	20.00	$152,421	$1,764,673	$14,236,848
6.00	Nov-03	5.0%	$16,044,305	$166,860,767	19.00	$139,051	$1,397,192	$15,633,838
7.00	Dec-03	5.0%	$16,044,305	$150,816,462	18.00	$125,680	$1,323,655	$16,957,493
8.00	Jan-04	4.0%	$12,835,444	$137,981,019	17.00	$114,984	$1,000,095	$17,957,588
9.00	Feb-04	4.0%	$12,835,444	$125,145,575	16.00	$104,288	$941,286	$18,898,854
10.00	Mar-04	4.0%	$12,835,444	$112,310,132	15.00	$93,592	$882,437	$19,781,290
11.00	Apr-04	3.0%	$9,626,583	$102,683,549	14.00	$85,570	$617,706	$20,398,998
12.00	May-04	3.0%	$9,626,583	$93,056,966	13.00	$77,547	$573,584	$20,972,580
13.00	Jun-04	3.0%	$9,626,583	$83,430,383	12.00	$69,525	$529,462	$21,502,042
14.00	Jul-04	3.0%	$9,626,583	$73,803,801	11.00	$61,503	$485,340	$21,987,382
15.00	Aug-04	3.0%	$9,626,583	$64,177,218	10.00	$53,481	$441,218	$22,428,601
16.00	Sep-04	3.0%	$9,626,583	$54,550,635	9.00	$45,459	$397,097	$22,825,697
17.00	Oct-04	3.0%	$9,626,583	$44,924,053	8.00	$37,437	$352,975	$23,178,672
18.00	Nov-04	2.0%	$6,417,722	$38,506,331	7.00	$32,089	$205,902	$23,384,574
19.00	Dec-04	2.0%	$6,417,722	$32,088,609	6.00	$26,741	$176,487	$23,561,061
20.00	Jan-05	2.0%	$6,417,722	$25,670,887	5.00	$21,392	$147,073	$23,708,134
21.00	Feb-05	2.0%	$6,417,722	$19,253,165	4.00	$16,044	$117,658	$23,825,792
22.00	Mar-05	2.0%	$6,417,722	$12,835,444	3.00	$10,696	$88,244	$23,914,038
23.00	Apr-05	2.0%	$6,417,722	$6,417,722	2.00	$5,348	$58,829	$23,972,865
24.00	May-05	2.0%	$6,417,722	($0)	1.00	($0)	$29,415	$24,002,280
25.00								
26.00								
27.00								
28.00								
29.00								
30.00								
31.00								
32.00								
33.00								
34.00								
35.00								
36.00								
Total		100.0%	$320,888,090			$2,053,671	$24,002,280	

Draw-Down Percentages

No.	6-Month	12-Month	18-Month	24-Month	30-Month	36-Month
1.00	30.0%	25.0%	20.0%	15.0%	8.0%	6.0%
2.00	25.0%	20.0%	15.0%	10.0%	7.0%	6.0%
3.00	15.0%	10.0%	10.0%	6.0%	7.0%	5.0%
4.00	15.0%	7.0%	8.0%	6.0%	6.0%	5.0%
5.00	10.0%	7.0%	7.0%	6.0%	6.0%	5.0%
6.00	5.0%	6.0%	6.0%	5.0%	6.0%	5.0%
7.00		6.0%	5.0%	5.0%	5.0%	5.0%
8.00		5.0%	4.0%	4.0%	5.0%	4.0%
9.00		5.0%	3.0%	4.0%	5.0%	4.0%
10.00		4.0%	3.0%	4.0%	4.0%	4.0%
11.00		3.0%	3.0%	3.0%	4.0%	4.0%
12.00		2.0%	3.0%	3.0%	4.0%	4.0%
13.00			3.0%	3.0%	3.0%	3.0%
14.00			2.0%	3.0%	3.0%	3.0%
15.00			2.0%	3.0%	3.0%	3.0%
16.00			2.0%	3.0%	3.0%	2.0%
17.00			2.0%	3.0%	3.0%	3.0%
18.00			2.0%	2.0%	2.0%	3.0%
19.00				2.0%	2.0%	2.0%
20.00				2.0%	2.0%	2.0%
21.00				2.0%	2.0%	2.0%
22.00				2.0%	2.0%	2.0%
23.00				2.0%	1.0%	2.0%
24.00				2.0%	1.0%	2.0%
25.00					1.0%	2.0%
26.00					1.0%	2.0%
27.00					1.0%	1.0%
28.00					1.0%	1.0%
29.00					1.0%	1.0%
30.00					1.0%	1.0%
31.00						1.0%
32.00						1.0%
33.00						1.0%
34.00						1.0%
35.00						1.0%
36.00						1.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

P1143
1017

JECT: SPRING 'ON
ıNCIAL PROJECı
CONFIGURATION
AL PROJECT COST $356,442,041

	1	2	3	[illegible]	5	6	7	[illegible]	9	10
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
UMPTIONS-REVENUE										
A. ELECTRIC ENERGY REVENUE										
1. MW BASE CAPACITY	420	420	420	420	420	420	420	420	420	420
MW PEAKING CAPACITY 100%	539	539	539	539	539	539	539	539	539	599
2. ANNUAL OPERATING HOURS	4,000	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680
18 hr/d,6d/wk,52 wkp/yr	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0
Total Operating Hours	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680
Cumulative Equivalent Operating Hours	4,680	9,360	14,040	23,153	27,833	32,513	37,193	41,873	46,553	51,233
3. TOTAL NUMBER OF STARTS	260	260	260	260	260	260	260	260	260	260
4. KWH SOLD 000's	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846
KWH	0	0	0	0	0	0	0	0	0	0
Total kWh Sold	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846

4/2/03

lOJECT: SPRING ON .
NANCIAL PROJECT.
1 CONFIGURATION
)TAL PROJECT COST $338,442,041

		1	2	3	4	5	6	7	8	9	10
		2005	2006	2007	2008	2008	2010	2011	2012	2013	2014
B. CAPACITY REVENUE											
Base Capacity MW		420	420	420	420	420	420	420	420	420	420
Capacity Payment	$kw/yr	$102.00	$102.00	$102.00	$102.00	$102.00	$102.00	$102.00	$102.00	$102.00	$102.00
		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Capacity Revenue		42,888,960	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960
C. FIXED O&M REVENUE											
Base Capacity MW		420	420	420	420	420	420	420	420	420	420
Fixed O&M Payment ($19.018/kw.yr)		$19.706	$20.182	$20.585	$20.997	$21.417	$21.846	$22.282	$22.728	$23.182	$23.646
Escalates with General Inflation											
Total Fixed O&M Revenue		8,319,817	8,486,010	8,655,730	8,828,844	9,005,421	9,185,530	9,369,240	9,556,625	9,747,758	9,942,713
D. VARIABLE O&M REVENUE											
Base Capacity MW		420	420	420	420	420	420	420	420	420	420
Total Cummulative Operting Hours		4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680
Variable O&M Payment ($4.410/mw.h)		$4.588	$4.680	$4.773	$4.869	$4.966	$5.068	$5.167	$5.270	$5.376	$5.483
Escalates with General Inflation											
Total Variable O&M Revenue		9,028,479	9,209,049	9,393,230	9,581,094	9,772,716	9,968,171	10,167,534	10,370,885	10,578,302	10,789,868
E. HEAT RATE BONUS/PENALITY											
Heat Rate Differential*	300.00	2,096,466	2,133,317	2,170,905	2,200,247	2,248,355	2,280,245	2,328,933	2,370,435	2,412,767	2,465,946
*300 btus /kwhr*op hrs*kw/1000*gas price											
F. FUEL PAYMENT (Pass Through)		51,413,607	52,317,370	53,239,208	54,179,483	55,138,564	56,116,826	57,114,653	58,132,437	59,170,577	60,229,479
G. START-UP BONUS											
START-UP REVENUE FACTOR											
# of On Time Starts		130	130	130	130	130	130	130	130	130	130
$ 20,000/On Time Start		20,808	21,224	21,649	22,082	22,523	22,974	23,433	23,902	24,380	24,867
START-UP BONUS		2,705,040	2,759,141	2,814,324	2,870,610	2,928,022	2,986,583	3,046,314	3,107,241	3,169,385	3,232,773
H. AVAILABILITY BONUS											
Bonus Factor ($1,000,000/% avail.>90%)		1,040,400	1,061,208	1,082,432	1,104,081	1,126,162	1,148,686	1,171,659	1,195,093	1,218,994	1,243,374
Bonus Factor Earned		2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Availability Bonus		2,601,000	2,653,020	2,706,080	2,760,202	2,815,406	2,871,714	2,929,148	2,987,731	3,047,486	3,108,436

4/2/03

PROJECT: SPRING 'ON
FINANCIAL PROJEC.
1x1 CONFIGURATION
TOTAL PROJECT COST $356,442,041

4/2/03

		1	2	3		5	6	7	8	9	10
		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
ASSUMPTIONS EXPENSES											
A. FUEL											
1. FUEL CONSUMPTION											
Base Heat Rate 7159 Btu/kw.h(HHV)		7,159	7,159	7,159	7,159	7,159	7,159	7,159	7,159	7,159	7,159
KWH Produced (000's)		1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846
Fuel Usage-Before Start-Up Gas (000's mmBtu (HHV))		14,088	14,088	14,088	14,088	14,088	14,088	14,088	14,088	14,088	14,088
Start-Up Gas (Hot Start)	750mmbtu's/turbine/s	390	390	390	390	390	390	390	390	390	390
TOTAL GAS USED IN OPERATIONS		14,478	14,478	14,478	14,478	14,478	14,478	14,478	14,478	14,478	14,478
2. FUEL COST PER UNIT											
Rate $/mmBtu (HHV) $3.00		3.121	3.184	3.247	3.312	3.378	3.446	3.515	3.585	3.657	3.730
Transportation $/mmBtu (HHV)		0.430	0.430	0.430	0.430	0.430	0.430	0.430	0.430	0.430	0.430
TOTAL FUEL PRICE		3.551	3.614	3.677	3.742	3.808	3.876	3.945	4.015	4.087	4.160
TOTAL FUEL EXPENSE		51,413,607	52,317,370	53,239,208	54,179,483	55,136,564	56,116,826	57,114,853	58,132,437	59,170,577	60,229,479
B. VARIABLE COSTS											
Chemical Lubricant & Ammonia Cost ($/Mwh)		0.2142	0.2185	0.2229	0.2273	0.2319	0.2365	0.2412	0.2460	0.2510	0.2560
Contingency ($/Mwh)		0.3265	0.3331	0.3398	0.3466	0.3535	0.3606	0.3678	0.3752	0.3827	0.3903
C. FIXED COSTS											
Property and Other Taxes	1.1600%	2,023,611	2,675,982	2,729,501	2,784,091	2,839,773	2,896,569	2,954,500	3,013,590	3,073,862	3,135,339
O&M Labor		1,690,650	1,724,463	1,758,952	1,794,131	1,830,014	1,866,614	1,903,946	1,942,025	1,980,866	2,020,483
Compliance & Professional Fees		260,100	265,302	270,608	276,020	281,541	287,171	292,915	298,773	304,749	310,844
General & Administrative (GP)		780,300	795,906	811,824	828,061	844,622	861,514	878,745	896,319	914,246	932,531
Operator Fee		312,120	318,362	324,730	331,224	337,849	344,606	351,498	358,528	365,698	373,012
Operator Bonus		780,300	795,906	811,824	828,061	844,622	861,514	878,745	896,319	914,246	932,531
Management Fee (GP)		260,100	265,302	270,608	276,020	281,541	287,171	292,915	298,773	304,749	310,844
Insurance		1,872,720	1,910,174	1,948,378	1,987,345	2,027,092	2,067,634	2,108,987	2,151,167	2,194,190	2,238,074
Contingency		520,200	530,604	541,216	552,040	563,081	574,343	585,830	597,546	609,497	621,687

:OJECT: SPRING ON
JANCIAL PROJECTI
1 CONFIGURATION
)TAL PROJECT COST [$388,442,041]

4/2/03

		1	2	3	4	5	6	7	8	9	10
		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
D. VARIABLE O&M RESERVE											
ANNUAL OVERHAUL RESERVES											
GT Insp/OH Reserve	$890	6,505,013	6,635,113	6,767,815	6,903,172	7,041,235	7,182,060	7,325,701	7,472,215	7,621,659	7,774,092
$668/hr /turbine x 2										0	0
ST Insp/OH Reserve	$187	782,529	798,179	814,143	830,426	847,034	863,975	881,254	898,880	916,857	935,194
$ 9 million /56,000 hrs											
SCR Replacement Reserve	$173	811,512	827,742	844,297	861,183	878,407	895,975	913,894	932,172	950,816	969,832
$6 million /36,000 hrs											
Misc. Contingency	$ 0.2540	520,023	530,424	541,032	551,853	562,890	574,148	585,630	597,343	609,290	621,476
$0.2540 /Mwh											
ANNUAL RESERVE ACTIVITY											
GAS TURBINE											
Beginning Balance		0	6,505,013	13,140,126	19,907,941	26,811,113	33,852,348	7,182,060	14,507,761	21,979,976	29,601,635
Annual Accrual		6,505,013	6,635,113	6,767,815	6,903,172	7,041,235	7,182,060	7,325,701	7,472,215	7,621,659	7,774,092
Reserves Used							(33,852,348)				
Ending Balance		6,505,013	13,140,126	19,907,941	26,811,113	33,852,348	7,182,060	14,507,761	21,979,976	29,601,635	37,375,727
STEAM TURBINE											
Beginning Balance		0	782,529	1,580,708	2,394,851	3,225,277	4,072,311	4,936,286	5,817,541	6,716,420	7,633,277
Annual Accrual		782,529	798,179	814,143	830,426	847,034	863,975	881,254	898,880	916,857	935,194
Reserves Used											
Ending Balance		782,529	1,580,708	2,394,851	3,225,277	4,072,311	4,936,286	5,817,541	6,716,420	7,633,277	8,568,472
SCR											
Beginning Balance		0	811,512	1,639,254	2,483,551	3,344,734	4,223,141	5,119,116	6,033,010	932,172	1,882,988
Annual Accrual		811,512	827,742	844,297	861,183	878,407	895,975	913,894	932,172	950,816	969,832
Reserves Used									(6,033,010)		
Ending Balance		811,512	1,639,254	2,483,551	3,344,734	4,223,141	5,119,116	6,033,010	932,172	1,882,988	2,852,820
MISC CONTINGENCY											
Beginning Balance		0	520,023	1,050,447	541,032	1,092,885	562,890	1,137,037	585,630	1,182,974	609,290
Annual Accrual		520,023	530,424	541,032	551,853	562,890	574,148	585,630	597,343	609,290	621,476
Reserves Used				(1,050,447)		(1,092,885)		(1,137,037)		(1,182,974)	
Ending Balance		520,023	1,050,447	541,032	1,092,885	562,890	1,137,037	585,630	1,182,974	609,290	1,230,766
TOTAL OVERHAUL RESERVE											
Beginning Balance		0	8,619,077	17,410,535	25,327,376	34,474,009	42,710,690	18,374,499	26,943,942	30,811,542	39,727,190
Annual Accrual		8,619,077	8,791,458	8,967,287	9,146,633	9,329,566	9,516,157	9,706,480	9,900,610	10,098,622	10,300,594
Reserves Used		0	0	(1,050,447)	0	(1,092,885)	(33,852,348)	(1,137,037)	(6,033,010)	(1,182,974)	0
Ending Balance		8,619,077	17,410,535	25,327,376	34,474,009	42,710,690	18,374,499	26,943,942	30,811,542	39,727,190	50,027,784
DEBT RESERVE (FROM BELOW)		8,762,818	8,762,818	8,762,818	0	0	0	0	0	0	0
WORKING CAP RESERVE (BELOW)		0	0	0	0	0	0	0	0	0	0
TOTAL RESERVE FUNDS		17,381,894	26,173,352	34,090,193	34,474,009	42,710,691	18,374,500	26,943,943	30,811,543	39,727,191	50,027,786
INTEREST INCOME	2.50%	217,274	544,441	753,294	867,053	964,809	763,565	666,481	721,944	881,734	1,121,937
ESCALATION FACTORS											
GAS ESCALATION		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
GENERAL INFLATION		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
PROPERTY TAXES		1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%

P1152

OJECT. SPRING ϽN												
IANCIAL PROJECTı												
I CONFIGURATION			1	2	3		5	6	7	8	9	10
TAL PROJECT COST		$355,442,041	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
ƆOME AND CASHFLOW STATEMENT												
ECTRIC REVENUE.												
Capacity Sales			42 888 960	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960	42 888 960
Fixed O&M Revenue			8 319 617	8,486,010	8,655,730	8,828,844	9,005,421	9,185,630	9,369,240	9,656,625	9,747,758	9 942 713
Variable O&M Revenue			9,028 479	9,209,049	9,393,230	9,581,094	9,772,716	9,968,171	10,167,534	10,370,885	10,578,302	10,789,868
Heat Rate Bonus/Penalty			2,096,465	2,133,317	2,170,906	2,209,247	2,248,355	2,288,245	2,328,933	2,370,435	2,412,767	2,455,945
Fuel Payment			51,413 607	52,317,370	53,239,208	54,179,483	55,138,664	56,116,826	57,114,853	58,132,437	59,170,577	60,229,479
Availability Bonus Payment			2 705,040	2,759,141	2,814,324	2,870,610	2,928,022	2,986,583	3,046,314	3,107,241	3,169,385	3,232,773
Startup Bonus Payment			2,601,000	2,653,020	2,706,080	2,760,202	2,815,406	2,871,714	2,929,148	2,987,731	3,047,486	3,108,436
			119,053,169	120,446,867	121,868,439	123,318,442	124,797,445	126,306,029	127,844,784	129,414,314	131,015,235	132,648,174
TEREST REVENUE			217,274	544,441	753,294	857,053	964,809	763,665	566,481	721,944	881,734	1,121,937
ϽTAL REVENUE			119,270,442	120,991,307	122,621,733	124,175,494	125,762,254	127,069,594	128,411,264	130,136,258	131,896,969	133,770,112
PERATING EXPENSES												
Fuel Costs			51,413 607	52,317,370	53,239,208	54,179,483	55,138,564	56,116,828	57,114,653	58,132,437	59,170,577	60,229,479
Property and Other Taxes			2,623,511	2,675,982	2,729,501	2,784,091	2,839,773	2,896,569	2,954,500	3,013,590	3,073,862	3,135,339
O&M Labor			1,690 650	1,724,463	1,758,952	1,794,131	1,830,014	1,866,614	1,903,946	1,942,025	1,980,866	2,020,483
Compliance & Professional Fees			260,100	265,302	270,608	276,020	281,541	287,171	292,916	298,773	304,749	310,844
General & Administrative			780,300	795,906	811,824	828,061	844,622	861,514	878,745	896,319	914,246	932,531
Operator Fee			312 120	318,362	324,730	331,224	337,849	344,606	351,498	358,528	365,698	373,012
Operator Bonus			780,300	795,906	811,824	828,061	844,822	861,514	878,745	896,319	914,246	932,531
Management Fee			260,100	265,302	270,608	276,020	281,541	287,171	292,915	298,773	304,749	310,844
Insurance			1,872 720	1,910,174	1,948,378	1,987,345	2,027,092	2,067,634	2,108,987	2,151,167	2,194,190	2,238,074
Chem Lubricant&Ammonia			421,513	429,943	438,542	447,313	456,259	465,384	474,692	484,186	493,869	503,747
Contingency			520,200	530,604	541,216	552,040	563,081	574,343	585,830	597,546	609,497	621,687
			60,935,121	62,029,315	63,145,392	64,283,790	65,444,957	66,629,347	67,837,425	69,069,664	70,326,648	71,608,570
PERATING CASHFLOW			58,335,321	58,961,993	59,476,341	59,891,704	60,317,297	60,440,247	60,573,840	61,066,594	61,570,421	62,161,542
EBT SERVICE REQUIREMENTS												
Principal Payment on Debt			5,322,418	5,758,449	6,201,589	6,677,905	7,194,507	7,751,394	8,346,196	8,990,764	9,682,725	10,431,561
Interest Payment			17,525,635	17,106,326	16,653,959	16,166,668	15,641,831	15,076,428	14,467,437	13,811,524	13,105,092	12,344,097
			22,848,053	22,864,775	22,855,648	22,844,573	22,836,338	22,827,822	22,813,633	22,802,288	22,787,818	22,775,658
˙ASHFLOW BEFORE OTHER ITEMS			35,487,268	36,097,218	36,620,793	37,047,131	37,480,959	37,612,425	37,760,207	38,264,306	38,782,603	39,385,884
ϽTHER ITEMS												
Fees Payment			0	0	0	0	0	0	0	0	0	0
Contribution to Reserves			(8,619,077)	(8,791,458)	(8,967,287)	(383,816)	(9,329,666)	(9,516,167)	(9,706,480)	(9,900,610)	(10,098,622)	(10,300,594)
Working Capital/other					0	0	0	0	0	0	0	0
			(8 619,077)	(8,791,458)	(8,967,287)	(383,816)	(9,329,566)	(9,516,157)	(9,706,480)	(9,900,610)	(10,098,622)	(10,300,594)
DEBT RESERVE									0			
Release of Debt Reserve						8,762,818						
Refinancing Proceeds												
DISTRIBUTABLE CASHFLOW			26 868,191	27,305,760	27,653,506	45,426,133	28,151,393	28,096,268	28,053,727	28,363,696	28 683,981	29,085,289
EQUITY AMOUNT INVESTED	$	(118 468,832)	26,868,191	27,305,760	27,653,506	45,426,133	28,151,393	28,096,268	28,053,727	28,363,696	28,683,981	29,085,289
Pre Tax IRR of Equity (20 years)			24.73%									
CASH FLOW DISTRIBUTION												
OUTSIDE Pre-Tax IRR to Equity (20 year)												
74 60%	$	(118 468,832)	20,016,802	20,342,791	20,601,862	33,842,469	20,972,788	20,931,720	20,900,026	21,130,954	21,369,566	21,668,640
			18.01%									
Total Outside Cash Flow	$	(118,468 832)	21,387,080	21,735,385	22,012,191	36,159,202	22,408,509	22,364,629	22,330,766	22,577,502	22,832,449	23,161,890
(20% remaining)			18.38%									
USA Power Partners @ (80% of Remaining Cash Flow)			5,481,111	5,570,376	5,641,315	9,266,931	5,742,884	5,731,639	5,722,960	5,786,194	5,851,532	5,933,398

4/2/03

		1	2	3	[illegible]	5	6	7	8	9		4/2/03
JECT· SPRINC ON												
\NCIAL PROJEC\												
CONFIGURATION	$355,442,041											
AL PROJECT COS⁻		2005	2008	2007	2008	2009	2010	2011	2012	2013	201-	
AL PROJECT COS⁻	$355,442,041											
SENT VALUE OF USA CASH FLOW	1 10	5 662,305	5,231,381	4,816,368	7,192,544	4,062,136	3,676,646	3,337,254	3,067,369	2,820,024	2,599 525	
DISCOUNT RATE		5,662,305	10,893,686	15,710,054	22,902,698	26,954,733	30,631,280	33,968,534	37,035,922	39,855,946	42,455,47-	
PRESENT VALUE		58,747,502										
20 Year Present Value												
NIOR DEBT SERVICE												
INTEREST RATES												
Treasury Bond rate		4.500%	4.000%	4.500%	4 500%	4.500%						
Interest Rate Spreads		3 000%	3 000%	3.000%	3.000%	3.000%						
Effective Years		Yr 1-4	Yr 5-8	Yr 9-12	Yr 13-15	Yr 16-20						
AMORTIZATION SCHEDULE	Tranche A											
QRTR #1 Percentage Amortization		0 55%	0.59%	0 64%	0.69%	0 74%	0.80%	0.86%	0 92%	0 99%	1 07%	
QRTR #2 Percentage Amortization		0 56%	0 60%	0 65%	0.70%	0 75%	0 81%	0.87%	0 94%	1 01%	1 09%	
QRTR #3 Percentage Amortization		0 56%	0 61%	0 66%	0 71%	0 77%	0.83%	0.89%	0 96%	1 03%	1 11%	
QRTR #4 Percentage Amortization		0 58%	0.62%	0 67%	0.72%	0 78%	0 84%	0.91%	0 98%	1 05%	1 13%	
Tota		2.25%	2 43%	2.62%	2.82%	3 04%	3.27%	3.52%	3 79%	4 09%	4 40%	
PRINCIPAL PAYMENTS												
QRTR #1 Principal	Tranche A	1,298,613	1,400,512	1,507,150	1,623,266	1,748,862	1,883,937	2,028,491	2,184,893	2,353,144	2,535,613	
QRTR #2 Principal	Tranche A	1,324,680	1,426,579	1,535,586	1,654,073	1,782,039	1,919,483	2,066,406	2,227,548	2 398,169	2 583,008	
QRTR #3 Principal	Tranche A	1,324,680	1,452,646	1,564,023	1,684,880	1,816,215	1,955,029	2,106,692	2,267,834	2,443,194	2,632,772	
QRTR #4 Principal	Tranche A	1 374,445	1,478,713	1,594,830	1,715,686	1,848,391	1,992,945	2,144,608	2,310,489	2,488,219	2,680,167	
Total Principal		5,322,418	6,758,449	8,201,689	6,677,905	7,194,607	7,751,394	8,346,196	8,990,764	9,682,725	10,431,561	
Period Beginning Balance	60 67%	236 973,208	231,650,790	225,892,341	219,690,752	213,012,847	205,818,341	198,066,947	189,720,751	180,729,987	171,047,262	
Payments		5,322,418	5,758,449	8,201,589	6,677,905	7,194,607	7,751,394	8,346,196	8,990,764	9,682,725	10,431,561	
Period Ending Balance		231,650,790	225,892,341	219,690,752	213,012,847	205,818,341	198,066,947	189,720,751	180,729,987	171,047,262	160,615,701	
PRINCIPAL PAYMENTS												
Tranch A												
QRTR #1 Principal		1,298,613	1,400,512	1,507,150	1,623,266	1,748,862	1,883,937	2,028,491	2,184,893	2 353,144	2 535,613	
QRTR #2 Principal		1,324,680	1,426,679	1,535,586	1,654,073	1,782,039	1,919,483	2,066,406	2,227,548	2,398,169	2,583,008	
QRTR #3 Principal		1,324,680	1,452,646	1 564,023	1,684,880	1,816,215	1,955,029	2,106,692	2,267,834	2,443,194	2,632,772	
QRTR #4 Principal		1,374,445	1,478,713	1,594,830	1,715,686	1,848,391	1,992,945	2,144,608	2,310,489	2,488,219	2,680,167	
Total Principal		6,322,418	5,758,449	6,201,889	6,677,905	7,194,607	7,761,394	8,346,196	8,990,764	9,682,725	10,431,561	
Period Beginning Balance		236,973,208	231,650,790	225,892,341	219,690,752	213,012,847	205,818,341	198,066,947	189,720,751	180,729,987	171,047,262	
Payments		6,322,418	5,768,449	6,201,589	6,877,905	7,194,607	7,761,394	8,346,196	8,990,764	9 682,725	10,431,581	
Period Ending Balance		231,650,790	225,892,341	219,690,752	213,012,847	205,818,341	198,066,947	189,720,751	180,729,987	171,047,262	160,616,701	
INTEREST PAYMENTS		1	2	3	4	5	6	7	8	9	10	
Interest Rate on Debt (swap amount)		4 50%	4 50%	4 50%	4 50%	4.50%	4 50%	4.50%	4.50%	4 50%	4 50%	
Spread		3 00%	3 00%	3.00%	3.00%	3 000%	3 000%	3 000%	3 000%	3 000%	3 000%	
All-in Rate		7 50%	7 50%	7.50%	7.50%	7 60%	7.50%	7.50%	7.60%	7.50%	7 50%	
QRTR #1 Interest		4,418,899	4,317,193	4,207,222	4,088,765	3,961,200	3,823,770	3,875,721	3 516,297	3,344,566	3 159,593	
QRTR #2 Interest		4,394,061	4,290,444	4,178,430	4,057,761	3 927,786	3,787,780	3,636,976	3,474,531	3,299,600	3,111,162	
QRTR #3 Interest		4,369 223	4,263,207	4,149,105	4,026,160	3,893,751	3,751,123	3,597,475	3,432,009	3,253,790	3 061,798	
QRTR #4 Interest		4,343,452	4,235,481	4,119,202	3,993,991	3,859,094	3,713,755	3,557,264	3,388,687	3,207,136	3,011,644	
Total Interest		17,525,635	17,106,326	16,653,959	16,166,668	15,641,831	16,076,428	14,467,437	13,811,524	13 105,092	12 344,097	
Annual Admin						-	-	-	-	-	-	
LOC Fee Payment		0	0	0	0	0	0	0	0	0	0	
Total Interest and Fees		17,525,635	17,106,326	16,653,959	16,166,668	15,641,831	15,076,428	14,467,437	13,811,524	13,105,092	12,344,097	
DEBT RESERVE							0	0	-	0	0	
Beginning		8,762 818	8,762 818	3,762,818	8,762,818		0	C		0	0	
Addition			0	0	(0,762,810)			0		0	0	
Ending		8,762 818	8,762,818	8,762,818	0							
Debt Coverage Ratio		2 553	2.579	2.602	2.622	2.641		2 655	2.676	2.702	2.729	
WORKING CAPITAL RESERVE					0	0	C		0	0		
Beginning			0	0	0	0	0		0	0		
Addition to Working Capital			0	0	4/2/03	0	0		0			
Ending				0	0	0	0					

OJECT SPRINC YON
IANCIAL PROJEC
1 CONFIGURATION
ITAL PROJECT COST $330,442,041

4/2/03

		11	12	13	14	15	16	17	18	19	20
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
SUMPTIONS-REVENUE											
A. ELECTRIC ENERGY REVENUE											
1 MW BASE CAPACITY		420	420	420	420	420	420	420	420	420	420
MW PEAKING CAPACITY	100%	539	539	539	539	539	539	539	539	539	539
2 ANNUAL OPERATING HOURS											
18 hr/d 5d/wk,52 wkp/yr		4 680	4,680	4,680	4,680	4,680	4,680	4 680	4,680	4,680	4,680
		0	0	0	0		0	0	0	0	0
		0	0	0	0		0	0	0	0	0
		0	0	0	0		0	0	0	0	0
Total Operating Hours		4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680
Cumulative Equivalent Operating **Hours**		55,913	60 593	65,273	69,953	74,633	79,313	83,993	88,673	93,353	98,033
3 TOTAL NUMBER OF STARTS		260	260	260	260	260	260	260	260	260	260
4 KWH SOLD 000 s											
KWH		1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846
		0	0	0	0	0	0	0	0	0	0
Total kWh Sold		1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846

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UECT: SPRING
NCIAL PROJECTI
CONFIGURATION
AL PROJECT COST $356,442,041

		11	12	13	14	15	16	17	18	19	20
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
B. CAPACITY REVENUE											
Base Capacity MW		420	420	420	420	420	420	420	420	420	420
Capacity Payment	$kw/yr	$102.00	$102.00	$102.00	$102.00	$102.00	$102.00	$102.00	$102.00	$102.00	$102.00
		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Capacity Revenue		42,888,960	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960
C. FIXED O&M REVENUE											
Base Capacity MW		420	420	420	420	420	420	420	420	420	420
Fixed O&M Payment ($19.018/kw.yr)		$24.119	$24.601	$25.093	$25.595	$26.107	$26.629	$27.162	$27.705	$28.259	$28.824
Escalates with General Inflation											
Total.Fixed O&M Revenue		10,141,567	10,344,398	10,551,286	10,762,312	10,977,558	11,197,109	11,421,052	11,649,473	11,882,462	12,120,111
D. VARIABLE O&M REVENUE											
Base Capacity MW		420	420	420	420	420	420	420	420	420	420
Total Cummulative Operting Hours		4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680
Variable O&M Payment ($4.410/mw.h)		$5.593	$5.705	$5.819	$5.935	$6.054	$6.175	$6.298	$6.424	$6.553	$6.684
Escalates with General Inflation											
Total Variable O&M Revenue		11,005,666	11,225,779	11,450,295	11,679,301	11,912,887	12,151,144	12,394,167	12,642,051	12,894,892	13,152,789
E. HEAT RATE BONUS/PENALITY											
Heat Rate Differential*	300.00	2,499,987	2,544,909	2,590,731	2,637,468	2,685,140	2,733,766	2,763,364	2,833,955	2,855,657	2,938,191
*300 btus /kwhr*op hrs*kw/1000*gas price											
F. FUEL PAYMENT (Pass Through)		61,309,560	62,411,242	63,534,967	64,681,147	65,850,261	67,042,767	68,259,103	69,499,776	70,765,262	72,056,058
G. START-UP BONUS											
START-UP REVENUE FACTOR											
# of On Time Starts		130	130	130	130	130	130	130	130	130	130
$ 20,000/On Time Start		25,365	25,872	26,390	26,917	27,456	28,005	28,565	29,136	29,719	30,313
START-UP BONUS		3,297,429	3,363,377	3,430,645	3,499,258	3,569,243	3,640,628	3,713,440	3,787,709	3,863,463	3,940,732
H. AVAILABILITY BONUS											
Bonus Factor ($1,000,000/% avail.>90%)		1,268,242	1,293,607	1,319,479	1,345,868	1,372,786	1,400,241	1,428,246	1,456,811	1,485,947	1,515,666
Bonus Factor Earned		2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Availability Bonus		3,170,604	3,234,017	3,298,697	3,364,671	3,431,964	3,500,604	3,570,616	3,642,028	3,714,868	3,789,166

0860

ROJECT: SPRING ?N
INANCIAL PROJECTI
X1 CONFIGURATION
OTAL PROJECT COST $369,442,041

4/2/03

		11	12	13	14	15	16	17	18	19	20
		2015	2016	2017	2018	2018	2020	2021	2022	2023	2024
ASSUMPTIONS EXPENSES											
A. FUEL											
1. FUEL CONSUMPTION											
Base Heat Rate 7159 Btu/kw.h(HHV)		7,159	7,159	7,159	7,169	7,159	7,169	7,159	7,159	7,159	7,159
KWH Produced (000's)		1,967,846	1,967,846	1,967,846	1,967,848	1,967,846	1,967,846	1,967,848	1,967,846	1,967,846	1,967,846
Fuel Usage-Before Start-Up Gas (000's mmBtu (HHV))		14,088	14,088	14,088	14,088	14,088	14,088	14,088	14,088	14,088	14,088
Start-Up Gas (Hot Start)	750mmbtu's/turbine/s	390	390	390	390	390	390	390	390	390	390
TOTAL GAS USED IN OPERATIONS		14,478	14,478	14,478	14,478	14,478	14,478	14,478	14,478	14,478	14,478
2. FUEL COST PER UNIT											
Rate $/mmBtu (HHV) $3.00		3.805	3.881	3.958	4.038	4.118	4.201	4.285	4.370	4.458	4.547
Transportation $/mmBtu (HHV)		0.430	0.430	0.430	0.430	0.430	0.430	0.430	0.430	0.430	0.430
TOTAL FUEL PRICE		4.235	4.311	4.388	4.468	4.548	4.631	4.716	4.800	4.888	4.977
TOTAL FUEL EXPENSE		81,309,560	62,411,242	63,534,957	64,681,147	65,850,261	67,042,757	68,259,103	69,499,776	70,765,262	72,056,058
B. VARIABLE COSTS											
Chemical Lubricant & Ammonia Cost ($/Mwh)		0.2611	0.2663	0.2717	0.2771	0.2826	0.2883	0.2941	0.2999	0.3059	0.3120
Contingency ($/Mwh)		0.3981	0.4061	0.4142	0.4225	0.4309	0.4396	0.4484	0.4573	0.4665	0.4758
C. FIXED COSTS											
Property and Other Taxes	1.1600%	3,198,046	3,262,007	3,327,247	3,393,792	3,461,668	3,530,901	3,601,519	3,673,549	3,747,020	3,821,961
O&M Labor		2,060,893	2,102,111	2,144,153	2,187,036	2,230,777	2,275,392	2,320,900	2,367,318	2,414,665	2,462,958
Compliance & Professional Fees		317,060	323,402	329,870	336,467	343,196	350,060	357,062	364,203	371,487	378,917
General & Administrative (GP)		951,181	970,205	989,609	1,009,401	1,029,589	1,050,181	1,071,185	1,092,608	1,114,461	1,136,750
Operator Fee		380,473	388,082	395,844	403,761	411,836	420,072	428,474	437,043	445,784	454,700
Operator Bonus		951,181	970,205	989,609	1,009,401	1,029,589	1,050,181	1,071,185	1,092,608	1,114,461	1,136,750
Management Fee (GP)		317,060	323,402	329,870	336,467	343,196	350,060	357,062	364,203	371,487	378,917
Insurance		2,282,835	2,328,492	2,375,062	2,422,563	2,471,014	2,520,435	2,570,843	2,622,260	2,674,705	2,728,199
Contingency		634,121	646,603	659,739	672,934	686,393	700,121	714,123	728,406	742,974	757,833

ROJECT: SPRING ... ON
NANCIAL PROJECTI
I CONFIGURATION
OTAL PROJECT COST $395,442,041

4/2/03

		11	12	13	14	15	16	17	18	19	20
		2015	2016	2017	2018	2018	2020	2021	2022	2023	2024
D. VARIABLE O&M RESERVE											
ANNUAL OVERHAUL RESERVES											
GT Insp/OH Reserve	$895	7,929,574	8,088,166	8,249,929	8,414,928	8,583,228	8,754,891	8,929,989	9,108,588	9,290,760	9,476,575
$668/hr /turbine x 2		0	0	0	0	0	0	0	0	0	0
ST Insp/OH Reserve	$187	953,898	972,976	992,436	1,012,284	1,032,530	1,053,181	1,074,244	1,095,729	1,117,644	1,139,997
$ 9 million /56,000 hrs											
SCR Replacement Reserve	$173	989,229	1,009,013	1,029,193	1,049,777	1,070,773	1,092,188	1,114,032	1,136,313	1,159,039	1,182,220
$6 million /36,000 hrs											
Misc. Contingency	0.2643	633,905	646,583	659,515	672,705	686,159	699,883	713,880	728,158	742,721	757,575
$0.2540 /Mwh											
ANNUAL RESERVE ACTIVITY											
GAS TURBINE											
Beginning Balance		37,375,727	7,929,574	16,017,740	24,267,669	32,682,597	41,265,823	8,754,891	17,684,879	26,793,468	36,084,228
Annual Accrual		7,929,574	8,088,166	8,249,929	8,414,928	8,583,228	8,754,891	8,929,989	9,108,588	9,290,760	9,476,575
Reserves Used		(37,375,727)					(41,265,823)				
Ending Balance		7,929,574	16,017,740	24,267,669	32,682,597	41,265,823	8,754,891	17,684,879	26,793,468	36,084,228	45,560,803
STEAM TURBINE											
Beginning Balance		8,568,472	953,898	1,926,874	2,919,310	3,931,594	4,964,124	6,017,305	7,091,549	8,187,279	9,304,922
Annual Accrual		953,898	972,976	992,436	1,012,284	1,032,530	1,053,181	1,074,244	1,095,729	1,117,644	1,139,997
Reserves Used		(8,568,472)									
Ending Balance		953,898	1,926,874	2,919,310	3,931,594	4,964,124	6,017,305	7,091,549	8,187,279	9,304,922	10,444,919
SCR											
Beginning Balance		2,852,820	3,842,048	4,851,062	5,880,255	6,930,032	1,070,773	2,162,961	3,276,993	4,413,306	5,572,345
Annual Accrual		989,229	1,009,013	1,029,193	1,049,777	1,070,773	1,092,188	1,114,032	1,136,313	1,159,039	1,182,220
Reserves Used						(6,930,032)					
Ending Balance		3,842,048	4,851,062	5,880,255	6,930,032	1,070,773	2,162,961	3,276,993	4,413,306	5,572,345	6,754,565
MISC CONTINGENCY											
Beginning Balance		1,230,766	633,905	1,280,489	659,515	1,332,220	686,159	1,386,042	713,880	1,442,038	742,721
Annual Accrual		633,905	646,583	659,516	672,705	686,159	699,883	713,880	728,158	742,721	757,575
Reserves Used		(1,230,766)		(1,280,489)		(1,332,220)		(1,386,042)		(1,442,038)	
Ending Balance		633,905	1,280,489	659,515	1,332,220	686,159	1,386,042	713,880	1,442,038	742,721	1,500,296
TOTAL OVERHAUL RESERVE											
Beginning Balance		50,027,784	13,359,426	24,076,165	33,726,749	44,876,444	47,986,880	18,321,199	28,767,302	40,836,090	51,704,216
Annual Accrual		10,506,606	10,716,738	10,931,073	11,149,695	11,372,689	11,600,142	11,832,145	12,068,788	12,310,164	12,556,367
Reserves Used		(47,174,965)	0	(1,280,489)	0	(8,262,253)	(41,265,823)	(1,386,042)	0	(1,442,038)	0
Ending Balance		13,359,426	24,076,165	33,726,749	44,876,444	47,986,880	18,321,199	28,767,302	40,836,090	51,704,216	64,280,583
DEBT RESERVE (FROM BELOW)		0	0	0	0	0	0	0	0	0	0
WORKING CAP RESERVE (BELOW)		0	0	0	0	0	0	0	0	0	0
TOTAL RESERVE FUNDS		13,359,427	24,076,166	33,726,750	44,876,445	47,986,881	18,321,200	28,767,304	40,836,092	51,704,217	64,260,585
INTEREST INCOME	2.50%	792,340	467,945	722,536	982,540	1,160,792	828,851	588,608	870,042	1,156,754	1,449,560
ESCALATION FACTORS											
GAS ESCALATION		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
GENERAL INFLATION		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
PROPERTY TAXES		1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%

ROJECT: SPRING ON
NANCIAL PROJECT
1 CONFIGURATION
OTAL PROJECT COST $355,442,041

4/2/03

		11	12	13	14	15	16	17	18	19	20
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ICOME AND CASHFLOW **STATEMENT**											
LECTRIC REVENUE:											
Capacity Sales		42,888,960	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960
Fixed O&M Revenue		10,141,567	10,344,398	10,551,286	10,762,312	10,977,558	11,197,109	11,421,052	11,649,473	11,882,462	12,120,111
Variable O&M Revenue		11,005,866	11,225,779	11,450,295	11,679,301	11,912,887	12,151,144	12,394,167	12,642,051	12,894,892	13,152,789
Heat Rate Bonus/Penalty		2,499,987	2,544,909	2,590,731	2,637,468	2,685,140	2,733,766	2,783,364	2,833,955	2,885,557	2,938,191
Fuel Payment		61,309,560	62,411,242	63,534,957	64,681,147	65,850,261	67,042,757	68,259,103	69,499,776	70,765,262	72,056,058
Availability Bonus Payment		3,297,429	3,363,377	3,430,645	3,499,258	3,569,243	3,640,628	3,713,440	3,787,709	3,863,463	3,940,732
Startup Bonus Payment		3,170,604	3,234,017	3,298,697	3,364,671	3,431,964	3,500,604	3,570,616	3,642,028	3,714,868	3,789,166
		134,313,772	136,012,682	137,745,571	139,513,117	141,316,013	143,154,968	145,030,702	146,943,951	148,895,464	150,886,008
ITEREST REVENUE		792,340	467,945	722,536	982,540	1,160,792	828,851	588,606	870,042	1,156,754	1,449,560
OTAL REVENUE		135,106,113	136,480,627	138,468,107	140,495,657	142,476,805	143,983,819	145,619,309	147,813,993	150,052,218	152,335,568
IPERATING EXPENSES											
Fuel Costs		61,309,560	62,411,242	63,534,957	64,681,147	65,850,261	67,042,757	68,259,103	69,499,776	70,765,262	72,056,058
Property and Other Taxes		3,198,046	3,262,007	3,327,247	3,393,792	3,461,668	3,530,901	3,601,619	3,673,549	3,747,020	3,821,961
O&M Labor		2,060,893	2,102,111	2,144,153	2,187,036	2,230,777	2,275,392	2,320,900	2,367,318	2,414,665	2,462,958
Compliance & Professional Fees		317,060	323,402	329,870	336,467	343,196	350,060	357,062	364,203	371,487	378,917
General & Administrative		951,181	970,205	989,609	1,009,401	1,029,589	1,050,181	1,071,185	1,092,608	1,114,461	1,136,750
Operator Fee		380,473	388,082	395,844	403,761	411,836	420,072	428,474	437,043	445,784	454,700
Operator Bonus		951,181	970,205	989,609	1,009,401	1,029,589	1,050,181	1,071,185	1,092,608	1,114,461	1,136,750
Management Fee		317,060	323,402	329,870	336,467	343,196	350,060	357,062	364,203	371,487	378,917
Insurance		2,282,835	2,328,492	2,375,062	2,422,563	2,471,014	2,520,435	2,570,843	2,622,260	2,674,705	2,728,199
Chem. Lubricant&Ammonia		513,822	524,098	534,580	545,272	556,177	567,301	578,647	590,220	602,024	614,064
Contingency		634,121	646,803	659,739	672,934	686,393	700,121	714,123	728,406	742,974	757,833
		72,916,232	74,250,048	75,610,539	76,998,241	78,413,697	79,857,461	81,330,101	82,832,194	84,364,329	85,927,106
)PERATING CASHFLOW		62,189,880	62,230,580	62,857,568	63,497,416	64,063,108	64,126,358	64,289,207	64,981,799	65,687,889	66,408,462
)EBT SERVICE REQUIREMENTS											
Principal Payment on Debt		11,237,270	12,106,961	13,035,896	14,040,663	15,128,370	16,294,278	17,547,866	18,900,983	20,363,108	21,934,240
Interest Payment		11,524,318	10,641,134	9,690,012	8,665,666	7,562,052	6,373,306	5,092,984	3,714,066	2,228,555	628,409
		22,761,588	22,748,095	22,725,908	22,706,329	22,690,422	22,667,583	22,640,850	22,615,049	22,591,663	22,562,649
:ASHFLOW BEFORE OTHER ITEMS		39,428,293	39,482,485	40,131,659	40,791,087	41,372,687	41,458,775	41,648,357	42,366,750	43,096,226	43,845,813
)THER ITEMS:											
Fees Payment		0	0	0	0	0	0	0	0	0	0
Contribution to Reserves		(10,506,606)	(10,716,738)	(10,931,073)	(11,149,695)	(11,372,689)	(11,600,142)	(11,832,145)	(12,068,788)	(12,310,164)	(12,556,367)
Working Capital/other		0	0	0	0	0	0	0	0	0	0
		(10,506,606)	(10,716,738)	(10,931,073)	(11,149,695)	(11,372,689)	(11,600,142)	(11,832,145)	(12,068,788)	(12,310,164)	(12,556,367)
DEBT RESERVE										0	
Release of Debt Reserve											
Refinancing Proceeds											
DISTRIBUTABLE CASHFLOW		28,921,686	28,765,746	29,200,586	29,641,392	29,999,998	29,858,632	29,816,212	30,297,962	30,786,062	31,289,446
EQUITY AMOUNT INVESTED:	$ (118,468,832)	28,921,686	28,765,746	29,200,586	29,641,392	29,999,998	29,858,632	29,816,212	30,297,962	30,786,062	31,289,446
Pre-Tax IRR of Equity (20 years)											
CASH FLOW DISTRIBUTION											
OUTSIDE Pre-Tax IRR to Equity (20 year) 74.60%	$ (118,468,832)	21,546,656	21,430,461	21,754,437	22,082,837	22,349,999	22,244,681	22,213,078	22,571,981	22,935,616	23,310,637
Total Outside Cash Flow (20% remaining)	$ (118,468,832)	23,021,662	22,897,534	23,243,666	23,594,548	23,879,999	23,767,471	23,733,705	24,117,177	24,505,706	24,906,399
USA Power Partners @ (10% of Remaining Cash Flow)		5,900,024	5,868,212	5,956,920	6,046,844	6,120,000	6,091,161	6,082,507	6,180,784	6,280,357	6,383,047

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TAL PROJECT COST	$355,442,041	11	12	13	14	15	16	17	18	19	20
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
TAL PROJECT COST	$355,442,041										
ESENT VALUE OF USA CASH FLOW											
DISCOUNT RATE	1.10	2,349,912	2,124,765	1,960,804	1,809,458	1,664,863	1,506,360	1,367,490	1,263,259	1,166,919	1,078,181
PRESENT VALUE		44,805,383	46,930,148	48,890,952	50,700,410	52,365,273	53,871,652	55,239,143	56,502,402	57,669,321	58,747,502
20 Year Present Value											
ENIOR DEBT SERVICE											
INTEREST RATES											
Treasury Bond rate											
Interest Rate Spreads											
Effective Years											
AMORTIZATION SCHEDULE	Tranche A										
QRTR #1 Percentage Amortization		1.15%	1.24%	1.34%	1.44%	1.55%	1.67%	1.80%	1.94%	2.09%	2.25%
QRTR #2 Percentage Amortization		1.17%	1.27%	1.36%	1.47%	1.58%	1.70%	1.83%	1.98%	2.13%	2.29%
QRTR #3 Percentage Amortization		1.20%	1.29%	1.39%	1.50%	1.61%	1.74%	1.87%	2.01%	2.17%	2.34%
QRTR #4 Percentage Amortization		1.22%	1.31%	1.41%	1.52%	1.64%	1.77%	1.90%	2.05%	2.21%	2.38%
Total		4.74%	5.11%	5.50%	5.93%	6.38%	6.88%	7.41%	7.98%	8.59%	9.26%
PRINCIPAL PAYMENTS											
QRTR #1 Principal	Tranche A	2,732,301	2,943,207	3,168,332	3,412,414	3,677,824	3,959,822	4,265,618	4,594,911	4,950,370	5,331,897
QRTR #2 Principal	Tranche A	2,782,065	2,997,711	3,227,575	3,476,397	3,746,546	4,035,654	4,346,089	4,680,221	5,042,790	5,431,426
QRTR #3 Principal	Tranche A	2,834,200	3,054,585	3,289,188	3,542,749	3,815,269	4,111,485	4,426,660	4,767,901	5,137,579	5,533,324
QRTR #4 Principal	Tranche A	2,886,703	3,111,458	3,350,801	3,609,102	3,888,730	4,187,317	4,609,600	4,857,951	5,232,368	5,637,593
Total Principal		11,237,270	12,106,961	13,035,896	14,040,663	15,128,370	16,294,278	17,547,866	18,900,983	20,363,108	21,934,240
Period Beginning Balance	60.87%	160,615,701	149,378,432	137,271,470	124,235,574	110,194,912	95,066,542	78,772,264	61,224,398	42,323,415	21,960,307
Payments		11,237,270	12,106,961	13,035,896	14,040,663	15,128,370	16,294,278	17,547,866	18,900,983	20,363,108	21,934,240
Period Ending Balance		149,378,432	137,271,470	124,235,574	110,194,912	95,066,542	78,772,264	61,224,398	42,323,416	21,960,307	26,067
PRINCIPAL PAYMENTS											
Tranch A											
QRTR #1 Principal		2,732,301	2,943,207	3,168,332	3,412,414	3,677,824	3,959,822	4,265,518	4,594,911	4,950,370	5,331,897
QRTR #2 Principal		2,782,065	2,997,711	3,227,575	3,476,397	3,746,548	4,035,654	4,346,089	4,680,221	5,042,790	5,431,426
QRTR #3 Principal		2,834,200	3,054,586	3,289,188	3,542,749	3,815,269	4,111,485	4,426,660	4,767,901	5,137,579	5,533,324
QRTR #4 Principal		2,888,703	3,111,458	3,350,801	3,609,102	3,888,730	4,187,317	4,509,800	4,857,951	5,232,368	5,637,593
Total Principal		11,237,270	12,106,961	13,035,898	14,040,663	15,128,370	16,294,278	17,547,866	18,900,983	20,363,108	21,934,240
Period Beginning Balance		160,615,701	149,378,432	137,271,470	124,235,674	110,194,912	95,066,542	78,772,264	61,224,398	42,323,415	21,960,307
Payments		11,237,270	12,106,961	13,035,896	14,040,663	15,128,370	16,294,278	17,547,866	18,900,983	20,363,108	21,934,240
Period Ending Balance		149,378,432	137,271,470	124,235,674	110,194,912	95,066,542	78,772,264	61,224,398	42,323,415	21,960,307	26,067
INTEREST PAYMENTS		11	12	13	14	15	16	17	18	19	20
Interest Rate on Debt (swap **amount**)		4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
Spread		3.000%	3.000%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
All-in Rate		7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%
QRTR #1 Interest		2,960,314	2,745,660	2,514,434	2,265,434	1,997,195	1,708,251	1,397,001	1,061,803	700,746	311,783
QRTR #2 Interest		2,908,150	2,689,453	2,453,917	2,200,252	1,926,948	1,632,682	1,315,512	974,049	606,192	209,943
QRTR #3 Interest		2,855,009	2,632,180	2,392,245	2,133,825	1,855,411	1,555,492	1,232,512	884,651	509,863	106,194
QRTR #4 Interest		2,800,846	2,573,840	2,329,417	2,066,155	1,782,498	1,476,980	1,147,957	793,564	411,756	489
Total Interest		11,524,318	10,641,134	9,690,012	8,665,666	7,562,052	6,373,306	5,092,984	3,714,066	2,228,555	628,409
Annual Admin		-	-	-	-	-	-	-	-	-	-
LOC Fee Payment		0	0	0	0	0	0	0	0	0	0
Total Interest and Fees		11,524,318	10,641,134	9,690,012	8,665,666	7,562,052	6,373,306	5,092,984	3,714,066	2,228,555	628,409
DEBT RESERVE											
Beginning		0	0	0	0	0	0	0	0	0	0
Addition		0	0	0	0	0	0	0	0	0	0
Ending		0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio		2.732	2.736	2.766	2.796	2.823	2.829	2.840	2.873	2.908	2.943
WORKING CAPITAL RESERVE											
Beginning		0	0	0	0	0	0	0	0	0	0
Addition to working capital		0	0	0	0 4/2/03	0	0	0	0	0	0
Ending		0	0	0	0	0	0	0	0	0	0

ɔJECT: SPRING ɔN
ANCIAL PROJECTI
CONFIGURATION
TAL PROJECT COST $353,412,041

4/2/03

	21	22	23	24	25	26	27	28	29	30
	2025	2026	2027	2028	2028	2030	2031	2032	2033	2034
SUMPTIONS-REVENUE										
A. ELECTRIC ENERGY REVENUE										
1. MW BASE CAPACITY	420	420	420	420	420	420	420	420	420	420
MW PEAKING CAPACITY 100%	539	539	539	539	539	539	539	539	539	539
2. ANNUAL OPERATING HOURS										
18 hr/d,5d/wk,52 wkp/yr	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680
	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0
Total Operating Hours	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680
Cumulative Equivalent Operating **Hours**	102,713	107,393	112,073	116,753	121,433	126,113	130,793	135,473	140,153	144,833
3. TOTAL NUMBER OF STARTS	260	260	260	260	260	260	260	260	260	260
4. KWH SOLD 000's										
KWH	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846
	0	0	0	0	0	0	0	0	0	0
Total kWh Sold	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846	1,987,846	1,967,846	1,967,846	1,967,846	1,967,846

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ROJECT: SPRING ON
NANCIAL PROJECT,
:1 CONFIGURATION
OTAL PROJECT COST $355,412,041

		21	22	23	24	25	26	27	28	29	30
		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
B. CAPACITY REVENUE											
Base Capacity MW		420	420	420	420	420	420	420	420	420	420
Capacity Payment	$kw/yr	$102.00	$102.00	$102.00	$102.00	$102.00	$102.00	$102.00	$102.00	$102.00	$102.00
		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Capacity Revenue		42,888,960	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960
C. FIXED O&M REVENUE											
Base Capacity MW		420	420	420	420	420	420	420	420	420	420
Fixed O&M Payment ($19.018/kw.yr)		$29.401	$29.989	$30.589	$31.201	$31.825	$32.461	$33.110	$33.772	$34.448	$35.137
Escalates with General Inflation											
Total Fixed O&M Revenue		12,362,514	12,609,764	12,861,959	13,119,198	13,381,582	13,649,214	13,922,198	14,200,642	14,484,655	14,774,348
D. VARIABLE O&M REVENUE											
Base Capacity MW		420	420	420	420	420	420	420	420	420	420
Total Cummulative Operting Hours		4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680	4,680
Variable O&M Payment ($4.410/mw.h)		$6.818	$6.954	$7.093	$7.235	$7.380	$7.527	$7.678	$7.831	$7.988	$8.148
Escalates with General Inflation											
Total Variable O&M Revenue		13,416,845	13,684,162	13,957,845	14,237,002	14,521,742	14,812,177	15,108,421	15,410,589	15,718,801	16,033,177
E. HEAT RATE BONUS/PENALITY											
Heat Rate Differential*	300.00	2,991,870	3,046,630	3,102,494	3,159,467	3,217,579	3,276,854	3,337,314	3,398,983	3,461,885	3,526,046
*300 btus /kwhr*op hrs*kw/1000*gas price											
F. FUEL PAYMENT (Pass Through)		73,372,670	74,715,614	76,085,417	77,482,617	78,907,760	80,361,406	81,844,125	83,356,498	84,899,119	86,472,592
G. START-UP BONUS											
START-UP REVENUE FACTOR											
# of On Time Starts		130	130	130	130	130	130	130	130	130	130
$ 20,000/On Time Start		30,920	31,538	32,169	32,812	33,468	34,138	34,820	35,517	36,227	36,952
START-UP BONUS		4,019,547	4,099,938	4,181,937	4,265,576	4,350,887	4,437,905	4,526,663	4,617,196	4,709,540	4,803,731
H. AVAILABILITY BONUS											
Bonus Factor ($1,000,000/% avail.>90%)		1,545,980	1,576,899	1,608,437	1,640,606	1,673,418	1,706,886	1,741,024	1,775,845	1,811,362	1,847,589
Bonus Factor Earned		2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Availability Bonus		3,864,949	3,942,248	4,021,093	4,101,515	4,183,545	4,267,216	4,352,561	4,439,612	4,528,404	4,618,972

PROJECT- SPRING ON
FINANCIAL PROJECTIN
2x1 CONFIGURATION
TOTAL PROJECT COST $358,442,647

		21	22	23	24	25	26	27	28	29	30
		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSUMPTIONS EXPENSES											
A FUEL											
1 FUEL CONSUMPTION											
Base Heat Rate 7159 Btu/kw.h(HHV)		7,159	7,159	7,159	7,159	7,159	7,159	7,159	7,169	7,159	7,159
KWH Produced (000 s)		1,967,846	1,967,846	1,967,846	1,967,846	1,987,846	1,967,846	1,967,846	1,967,846	1,967,846	1,967,846
Fuel Usage-Before Start-Up Gas (000 s mmBtu (HHV))		14,088	14,088	14,088	14,088	14,088	14,088	14,088	14,088	14,088	14,088
Start-Up Gas (Hot Start)	750mmbtu's/turbine/s	390	390	390	390	390	390	300	390	390	390
TOTAL GAS USED IN OPERATIONS		14,478	14,478	14,478	14,478	14,478	14,478	14,478	14,478	14,478	14,478
2. FUEL COST PER UNIT											
Rate $/mmBtu (HHV) $3 00		4.638	4.731	4.825	4.922	5.020	5.121	5.223	5.328	5.434	5.543
Transportation $/mmBtu (HHV)		0.430	0.430	0.430	0.430	0.430	0.430	0.430	0.430	0.430	0.430
TOTAL FUEL PRICE		5.068	5.161	5.255	5.352	5.450	5.551	5.653	5.758	5.864	5.973
TOTAL FUEL EXPENSE		73,372,670	74,715,614	76,085,417	77,482,617	78,907,760	80,361,406	81,844,125	83,358,498	84,899,119	86,472,592
B VARIABLE COSTS											
Chemical Lubricant & Ammonia Cost ($/Mwh)		0.3183	0.3247	0.3311	0.3370	0.3445	0.3514	0.3584	0.3656	0.3729	0.3804
Contingency ($/Mwh)		0.4863	0.4950	0.5049	0.5150	0.5253	0.5358	0.5465	0.5575	0.5686	0.5800
C FIXED COSTS											
Property and Other Taxes	1.1600%	3,898,400	3,976,368	4,055,895	4,137,013	4,219,754	4,304,149	4,390,232	4,478,036	4,567,597	4,658,949
O&M Labor		2,512,217	2,562,461	2,613,711	2,665,985	2,719,304	2,773,691	2,829,164	2,885,748	2,943,463	3,002,332
Compliance & Professional **Fees**		386,495	394,225	402,109	410,151	418,355	426,722	435,256	443,961	452,840	461,897
General & Administrative **(GP)**		1,159,485	1,182,674	1,206,328	1,230,454	1,255,064	1,280,165	1,305,768	1,331,884	1,358,621	1,385,692
Operator Fee		463,794	473,070	482,531	492,182	502,025	512,066	522,307	532,753	543,408	554,277
Operator Bonus		1,159,485	1,182,674	1,206,328	1,230,454	1,255,064	1,280,165	1,305,768	1,331,884	1,358,521	1,385,692
Management Fee (GP)		386,495	394,225	402,109	410,151	418,355	426,722	436,256	443,961	452,840	461,897
Insurance		2,782,763	2,838,419	2,895,187	2,953,091	3,012,153	3,072,398	3,133,844	3,196,520	3,260,451	3,325,660
Contingency		772,990	788,450	804,219	820,303	836,709	853,443	870,612	887,922	905,681	923,794

OJECT: SPRING ON
IANCIAL PROJECT
I CONFIGURATION
ITAL PROJECT COST $306,442,041

		21	22	23	24	25	26	27	28	29	30
		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
D. VARIABLE O&M RESERVE											
ANNUAL OVERHAUL RESERVES											
GT Insp/OH Reserve	$806	9,666,107	9,859,429	10,056,618	10,257,750	10,462,905	10,672,163	10,885,606	11,103,318	11,325,385	11,551,892
$666/hr /turbine x 2		0	0	0	0	0	0	0	0	0	0
ST Insp/OH Reserve	$187	1,162,797	1,186,053	1,209,774	1,233,969	1,258,648	1,283,821	1,309,498	1,335,688	1,362,402	1,389,650
$ 9 million /56,000 hrs											
SCR Replacement Reserve	$173	1,205,864	1,229,981	1,254,581	1,279,673	1,305,266	1,331,371	1,357,999	1,385,159	1,412,862	1,441,119
$8 million /36,000 hrs											
Misc. Contingency	0.2643	772,727	788,181	803,945	820,024	836,426	853,153	870,216	887,620	905,373	923,480
$0.2540 /Mwh											
ANNUAL RESERVE ACTIVITY											
GAS TURBINE											
Beginning Balance		45,560,803	9,666,107	19,525,536	29,582,153	39,839,903	50,302,808	10,672,163	21,557,769	32,661,088	43,986,472
Annual Accrual		9,666,107	9,859,429	10,056,618	10,257,750	10,462,905	10,672,163	10,885,606	11,103,318	11,325,385	11,551,892
Reserves Used		(45,560,803)					(50,302,808)				(43,986,472)
Ending Balance		9,666,107	19,525,536	29,582,153	39,839,903	50,302,808	10,672,163	21,557,769	32,661,088	43,986,472	11,551,892
STEAM TURBINE											
Beginning Balance		10,444,919	1,162,797	2,348,849	3,558,623	4,792,592	6,051,240	7,335,061	8,644,559	9,980,247	11,342,649
Annual Accrual		1,162,797	1,186,053	1,209,774	1,233,969	1,258,648	1,283,821	1,309,498	1,335,688	1,362,402	1,389,650
Reserves Used		(10,444,919)									(11,342,649)
Ending Balance		1,162,797	2,348,849	3,558,623	4,792,592	6,051,240	7,335,061	8,644,559	9,980,247	11,342,649	1,389,650
SCR											
Beginning Balance		6,754,565	7,960,429	1,229,981	2,484,562	3,764,235	5,069,501	6,400,873	7,758,872	9,144,030	1,412,862
Annual Accrual		1,205,864	1,229,981	1,254,581	1,279,673	1,305,266	1,331,371	1,357,999	1,385,159	1,412,862	1,441,119
Reserves Used			(7,960,429)							(9,144,030)	
Ending Balance		7,960,429	1,229,981	2,484,562	3,764,236	5,069,501	6,400,873	7,758,872	9,144,030	1,412,862	2,853,981
MISC CONTINGENCY											
Beginning Balance		1,500,296	772,727	1,560,908	803,945	1,623,969	836,426	1,689,578	870,216	1,757,836	905,373
Annual Accrual		772,727	788,181	803,945	820,024	836,425	853,153	870,216	887,620	905,373	923,480
Reserves Used		(1,500,296)		(1,560,900)		(1,623,969)		(1,689,578)		(1,757,836)	
Ending Balance		772,727	1,560,908	803,945	1,623,969	836,425	1,689,578	870,216	1,757,836	905,373	1,828,853
TOTAL OVERHAUL **RESERVE**											
Beginning Balance		64,260,583	19,562,059	24,665,276	36,429,284	50,020,699	62,259,974	26,097,675	38,831,416	53,543,202	57,647,356
Annual Accrual		12,807,495	13,063,644	13,324,917	13,591,416	13,863,244	14,140,509	14,423,319	14,711,785	15,006,021	15,306,142
Reserves Used		(57,506,019)	(7,960,429)	(1,560,908)	0	(1,623,969)	(50,302,808)	(1,689,578)	0	(10,901,867)	(55,329,121)
Ending Balance		19,562,059	24,665,276	36,429,284	50,020,699	62,259,974	26,097,676	38,831,416	53,543,202	57,647,356	17,624,376
DEBT RESERVE (FROM BELOW)		0	0	0	0	0	0	0	0	0	0
WORKING CAP RESERVE (BELOW)		0	0	0	0	0	0	0	0	0	0
TOTAL RESERVE FUNDS		19,562,060	24,665,276	36,429,285	50,020,701	62,259,975	26,097,676	38,831,418	53,543,203	57,647,357	17,624,378
INTEREST INCOME	2.50%	1,047,783	652,842	763,682	1,080,625	1,403,508	1,104,471	811,614	1,164,683	1,389,882	940,897
ESCALATION FACTORS											
GAS ESCALATION		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
GENERAL INFLATION		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
PROPERTY TAXES		1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%

ROJECT: SPRING ... ON
INANCIAL PROJECTI
x1 CONFIGURATION
OTAL PROJECT COST $300,442,041

		21	22	23	24	25
		2025	2026	2027	2028	2029
ICOME AND CASHFLOW STATEMENT						
LECTRIC REVENUE:						
Capacity Sales		42,888,960	42,888,960	42,888,960	42,888,960	42,888,960
Fixed O&M Revenue		12,362,514	12,609,764	12,861,959	13,119,198	13,381,582
Variable O&M Revenue		13,415,845	13,684,162	13,957,845	14,237,002	14,521,742
Heat Rate Bonus/Penalty		2,991,878	3,046,638	3,102,494	3,159,467	3,217,579
Fuel Payment		73,372,670	74,715,614	76,085,417	77,482,617	78,907,760
Availability Bonus Payment		4,019,547	4,099,938	4,181,937	4,265,576	4,350,887
Startup Bonus Payment		3,864,949	3,942,248	4,021,093	4,101,515	4,183,545
		152,916,363	154,987,325	157,099,706	159,254,335	161,452,056
NTEREST REVENUE		1,047,783	552,842	763,682	1,080,625	1,403,508
OTAL REVENUE		153,964,146	155,540,167	157,863,388	160,334,959	162,855,564
PERATING EXPENSES						
Fuel Costs		73,372,670	74,715,614	76,085,417	77,482,617	78,907,760
Property and Other Taxes		3,898,400	3,976,368	4,055,895	4,137,013	4,219,754
O&M Labor		2,512,217	2,562,461	2,613,711	2,665,985	2,719,304
Compliance & Professional Fees		386,495	394,225	402,109	410,151	418,355
General & Administrative		1,159,485	1,182,674	1,206,328	1,230,454	1,255,064
Operator Fee		463,794	473,070	482,531	492,182	502,025
Operator Bonus		1,159,485	1,182,674	1,206,328	1,230,454	1,255,064
Management Fee		386,495	394,225	402,109	410,151	418,355
Insurance		2,782,763	2,838,419	2,895,187	2,953,091	3,012,153
Chem, Lubricant&Ammonia		626,346	638,873	651,650	664,683	677,977
Contingency		772,990	788,450	804,219	820,303	836,709
		87,521,139	89,147,053	90,805,485	92,497,086	94,222,518
PERATING CASHFLOW		66,443,007	66,393,114	67,057,903	67,837,874	68,633,047
EBT SERVICE REQUIREMENTS						
Principal Payment on Debt		0	0	0	0	0
Interest Payment		0	0	0	0	0
		0	0	0	0	0
CASHFLOW BEFORE OTHER ITEMS		66,443,007	66,393,114	67,057,903	67,837,874	68,633,047
OTHER ITEMS:						
Fees Payment		0	0	0	0	0
Contribution to Reserves		(12,807,495)	(13,063,644)	(13,324,917)	(13,591,416)	(13,863,244)
Working Capital/other		0	0	0	0	0
		(12,807,495)	(13,063,644)	(13,324,917)	(13,591,416)	(13,863,244)
DEBT RESERVE						
Release of Debt Reserve						
Refinancing Proceeds						
DISTRIBUTABLE CASHFLOW		53,635,512	53,329,469	53,732,986	54,246,459	54,769,803
EQUITY AMOUNT INVESTED:	$ (118,468,832)	53,635,512	53,329,469	53,732,986	54,246,459	54,769,803
Pre-Tax IRR of Equity (20 years)						
CASH FLOW DISTRIBUTION						
OUTSIDE Pre-Tax IRR to Equity (20 yrear) 74.60%	$ (118,468,832)	39,958,457	39,730,455	40,031,074	40,413,612	40,803,503
Total Outside Cash Flow (20% remaining)	$ (118,468,832)	42,693,868	42,450,258	42,771,457	43,180,181	43,696,763
USA Power Partners @ (80% of Remaining Cash Flow)		10,941,645	10,879,212	10,861,529	11,066,278	11,173,040

	26	27	28	29	30
	2030	2031	2032	2033	2034
ICOME AND CASHFLOW STATEMENT					
LECTRIC REVENUE:					
Capacity Sales	42,888,960	42,888,960	42,888,960	42,888,960	42,888,960
Fixed O&M Revenue	13,649,214	13,922,198	14,200,642	14,484,655	14,774,348
Variable O&M Revenue	14,812,177	15,108,421	15,410,589	15,718,801	16,033,177
Heat Rate Bonus/Penalty	3,276,854	3,337,314	3,398,983	3,461,885	3,526,046
Fuel Payment	80,361,406	81,844,125	83,356,498	84,899,119	86,472,592
Availability Bonus Payment	4,437,905	4,526,663	4,617,196	4,709,540	4,803,731
Startup Bonus Payment	4,267,216	4,352,581	4,439,612	4,528,404	4,618,972
	163,693,732	165,880,241	168,312,480	170,691,364	173,117,826
NTEREST REVENUE	1,104,471	811,614	1,154,683	1,389,882	940,897
OTAL REVENUE	164,798,202	166,791,854	169,467,163	172,081,246	174,058,723
PERATING EXPENSES					
Fuel Costs	80,361,406	81,844,125	83,356,498	84,899,119	86,472,592
Property and Other Taxes	4,304,149	4,390,232	4,478,036	4,567,597	4,658,949
O&M Labor	2,773,691	2,829,164	2,885,748	2,943,463	3,002,332
Compliance & Professional Fees	426,722	435,256	443,961	452,840	461,897
General & Administrative	1,280,165	1,305,768	1,331,884	1,358,521	1,385,692
Operator Fee	512,066	522,307	532,753	543,408	554,277
Operator Bonus	1,280,165	1,305,768	1,331,884	1,358,521	1,385,692
Management Fee	426,722	435,256	443,961	452,840	461,897
Insurance	3,072,396	3,133,844	3,196,520	3,260,451	3,325,660
Chem, Lubricant&Ammonia	691,536	705,367	719,474	733,864	748,541
Contingency	853,443	870,512	887,922	905,681	923,794
	95,982,469	97,777,599	99,608,642	101,476,305	103,381,322
PERATING CASHFLOW	68,815,743	69,014,255	69,858,521	70,604,941	70,677,401
EBT SERVICE REQUIREMENTS					
Principal Payment on Debt	0	0	0	0	0
Interest Payment	0	0	0	0	0
	0	0	0	0	0
CASHFLOW BEFORE OTHER ITEMS	68,815,743	69,014,255	69,858,521	70,604,941	70,677,401
OTHER ITEMS:					
Fees Payment	0	0	0	0	0
Contribution to Reserves	(14,140,509)	(14,423,319)	(14,711,785)	(15,006,021)	(15,306,142)
Working Capital/other	0	0	0	0	0
	(14,140,509)	(14,423,319)	(14,711,785)	(15,006,021)	(15,306,142)
DEBT RESERVE					
Release of Debt Reserve					
Refinancing Proceeds					
DISTRIBUTABLE CASHFLOW	54,675,234	54,590,936	55,146,736	55,598,920	55,371,259
EQUITY AMOUNT INVESTED:	54,675,234	54,590,936	55,146,736	55,598,920	55,371,259
Pre-Tax IRR of Equity (20 years)					
CASH FLOW DISTRIBUTION					
OUTSIDE Pre-Tax IRR to Equity (20 yrear) 74.60%	40,733,050	40,570,248	41,084,318	41,421,195	41,251,688
Total Outside Cash Flow (20% remaining)	43,521,487	43,454,385	43,896,802	44,256,740	44,075,522
USA Power Partners @ (80% of Remaining Cash Flow)	11,153,748	11,136,551	11,249,934	11,342,180	11,295,737

		21	22	23	24	25	26	27	28	29	30
)JECT: SPRING											
ANCIAL PROJECT											
CONFIGURATION											
'AL PROJECT COST	$355,442,041	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
'AL PROJECT COST	$355,442,041										
:SENT VALUE OF USA CASH FLOW											
DISCOUNT RATE	1.10	1,680,171	1,518,713	1,391,095	1,276,716	1,171,849	1,063,478	965,307	886,486	812,505	809,178
PRESENT VALUE		60,427,673	61,946,386	63,337,481	64,614,197	65,786,046	66,849,524	67,814,831	68,701,317	69,513,822	70,323,000
20 Year Present Value											
IIOR DEBT SERVICE											
INTEREST RATES											
Treasury Bond rate											
Interest Rate Spreads											
Effective Years											
AMORTIZATION SCHEDULE	**Tranche A**										
QRTR #1 Percentage Amortization											
QRTR #2 Percentage Amortization											
QRTR #3 Percentage Amortization											
QRTR #4 Percentage Amortization											
Total											
PRINCIPAL PAYMENTS											
QRTR #1 Principal	Tranche A	0									
QRTR #2 Principal	Tranche A	0									
QRTR #3 Principal	Tranche A	0									
QRTR #4 Principal	Tranche A	0									
Total Principal											
Period Beginning Balance	60,877										
Payments											
Period Ending Balance											
PRINCIPAL PAYMENTS											
Tranch A											
QRTR #1 Principal											
QRTR #2 Principal											
QRTR #3 Principal											
QRTR #4 Principal											
Total Principal											
Period Beginning Balance											
Payments											
Period Ending Balance											
INTEREST PAYMENTS											
Interest Rate on Debt (swap amount)											
Spread											
All-in Rate											
QRTR #1 Interest											
QRTR #2 Interest											
QRTR #3 Interest											
QRTR #4 Interest											
Total Interest											
Annual Admin											
LOC Fee Payment											
Total Interest and Fees											
DEBT RESERVE											
Beginning											
Addition											
Ending											
Debt Coverage Ratio											
ORKING CAPITAL RESERVE											
Beginning											
Addition to working capital											
Ending											

Tab 6

4

CONFIDENTIAL

USA Power Partners LLC

Preliminary Offering Memorandum

Spring Canyon Energy LLC

450 Mw Natural Gas Fired,
Combined-Cycle Power Facility,
With Duct-Firing Capability for an
Additional 80 MW

Located in Juab County, Utah
With interconnection to the Western US RTO
Via the Mona (PacifiCorp) Substation

August 2002

PRELIMINARY OFFERING MEMORANDUM

SPRING CANYON ENERGY LLC

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PROJECT SUMMARY

SPRING CANYON ENERGY LLC

Project Facility Description

Spring Canyon Energy LLC ("SCE LLC") is developing the Spring Canyon Energy Project ("SCEP") as a base-load natural gas-fired combined cycle power generation facility. SCEP will have a nominal generating capacity of 420Mw utilizing two General Electric Frame 7-FA gas turbines each driving an electrical generator. The gas turbines will be fitted with air inlet chillers, which allow for additional power production when ambient air temperatures exceed 59° F. The exhaust of the gas turbines, augmented with additional heat when appropriate from natural gas-fired duct burners, will be directed to two heat recovery steam generators ("HRSGs"). The steam produced by the HRSGs will then drive a single steam turbine electrical generator to create additional "combined cycle" power. While a typical "2 on 1" arrangement is probable, the option to configure the facility with two "1 on 1" equipment trains is available. With the use of duct burners, power output can be boosted by up to 119Mw for a total plant capacity of 539Mw at 59°F. An air-cooled condenser will condense steam turbine exhaust into water for return to the HRSGs. Employing an air-cooled condenser greatly reduces SCEP's water usage requirements.

Project performance curves providing net plant output and net plant heat rate information are attached to a Waldron Engineering report describing the impacts of a "2 on 1" configuration versus the two "1 on 1" arrangement. The Waldron report also provides a summary of project cost and is included in Section 2. Conceptual engineering drawings showing the site plan and general arrangements are included in Section 5.

With regards to air emissions, SCEP is being configured with Lowest Achievable Emission Rate ("LAER") technology to control NO_X, CO and other criteria pollutants. NO_X emissions in the turbine exhaust will be controlled to 15ppm with Dry-Lo NO_X combustion technology prior to passing through Selective Catalytic Reduction ("SCR") NO_X catalyst. NO_X emissions will be controlled to 2.0ppm with the SCR and CO emissions will be controlled to 4.0ppm without the use of CO catalyst. In addition, SCEP will employ zero water discharge technology and therefore will have no liquid discharges to the surrounding environment.

Project permits are being secured in a manner, which would allow a phased approach to construction whereby one gas turbine/steam turbine could be constructed and operated prior to the construction of the second gas turbine/steam turbine. Discussions are in progress with several potential long-term power purchasers, which will determine if a phased approach will be employed.

Project Location

Spring Canyon Energy LLC's facility will be located 82 miles south of Salt Lake City, Utah, on 40 acres of currently undeveloped agriculture land approximately 2 miles west of the small community of Mona, Utah, and 0.75 miles north of the pivotal Mona Switching Station. PacifiCorp, the Los Angeles Department of Water & Power ("LADWP"), and the Deseret Generation & Transmission Co-op ("Deseret") jointly own the Mona Switching Station and have declared it to be an "open bus," meaning the owners conduct business at no cost (i.e. no wheeling charges). This provides SCEP with an uncommon marketing opportunity. Output from SCEP can literally access seven distinct power markets. Site aerials photos and topographical maps are included in Section 4.

Strategic Advantages

The Spring Canyon Energy LLC proposed generation facility is situated in the heart of the Western Electricity Coordinating Council ("WECC" formally the Western System Coordinating Council or "WSCC") and adjacent to the major power market in Utah, Salt Lake City. It's close proximity to the Mona Switching Station allows power to be distributed to generation deficient markets in Arizona, northern Nevada, southern Nevada, southern California, Idaho, Colorado and potentially, as far as the Pacific northwest region. The Mona Switching Station, which is owned by PacifiCorp, the LADWP, and Deseret, is located at a vital "crossroads" for power distribution in the western United States. With minimal upgrades, SCEP will be able to send its power point to point to multiple regional markets.

SCEP has access to relatively less costly Rocky Mountain natural gas, which consistently carries a lower burner-tip valuation than natural gas which is marketed for the California markets. SCEP will connect to Questar's Mainline 104 near its point of interconnection with the Kern River pipeline, approximately 10 miles north of the project site, near the small community of Elberta, Utah. Mainline 104 has daily capacity of 262 million cubic feet per day. The SCEP plant will require approximately 85 million cubic feet per day. The ability to access relatively higher priced western power markets combined with an abundance of relatively low priced, Rocky Mountain sourced fuel, ensures that SCEP will have a competitive spark spread advantage over other generators, even those located much closer to major power markets.

The facility will be located in Juab County, a county that is overwhelmingly agricultural in its economic base and whose residents desire the jobs and tax resources that SCEP will provide. Public hearings held in June for rezoning purposes revealed that county officials and the general public overwhelming support the project.

Power Markets

SCEP retained Navigant Consulting, Inc. (Navigant Consulting) to conduct an analysis of the viability of the principal power markets most easily accessible from SCEP and to help secure tolling agreements or off-take contracts. SCEP is presently discussing such sales arrangements with several of the most financially secure power purchasing entities in those regional markets. These discussions confirm that the need for new generating capacity has been masked by the economic recession and the mild temperatures associated with the 2001-2002 winter. The view of the markets is consistent in that an economic recovery will increase demand causing rising prices for natural gas and electricity. Additionally, a return to a normal weather pattern will further increase demand for power and raise prices. Finally, the Federal Energy Regulatory Commission (FERC) "cap" on electric wholesale prices in the WECC is scheduled to end on October 1, 2002, which may also lead to higher prices in the entire region.

The Navigant Consulting Market Assessment, which is attached as Section 3, concludes that SCEP can serve multiple viable markets with credit-worthy purchasers with resource or reserve deficiencies in the 10-year planning horizon. Among others, these markets include southern California, northern Nevada and Utah.

The turbulent marketplaces in California and the western United States have led to the cancellation of thousands of megawatts of proposed generation additions. Also, major generation developers have been hit with a credit crunch from too much debt accumulated during the past boom periods and are currently "shelving" proposed new units. This provides an excellent opportunity for SCEP to strategically target markets in addition to Utah.

SCEP's opportunities in southern California are a result of proposed projects being cancelled (in California) or denied siting (in Arizona) coupled with an expected economic recovery in California. SCEP is able to access the southern California marketplace either directly via the Intermountain Power Project direct current transmission line (IPP DC) or alternatively via AC transmission facilities from southern Utah through southern Nevada or Arizona into southern California.

Sierra Pacific Power Company, the investor-owned utility serving northern Nevada has a severe in-area resource deficiency. In fact, northern Nevada must import upwards of 40 percent of its energy requirements from out-of-state. This provides SCEP with a viable market to the immediate west of the Project.

In conclusion, the SCEP facility is strategically located to serve multiple markets. The project will be the lowest cost producer of natural gas fired generation in the western region, utilizing Rocky Mountain gas reserves. In addition, SCEP's generation will come on-line in a timeframe consistent with projection of significant market resurgence.

Air Permit

The Utah Division of Air Quality ("UDAQ") is currently reviewing the air permit application for the SCE facility, which was submitted in February 2002. Issuance of the final permit is expected in the August/September 2002 timeframe. While a detailed analysis of the status of the air permit from Dr. Ted D. Guth dated July 1, 2002 and the permit application are attached in Section 7, highlights of the permit application include the following:

- It is anticipated that SCEP will have a great deal of operational flexibility,'
- The operations will be "tons limited" versus "hours limited,"
- The facility will not have limitations on the number of startups, or the number of hours of gas turbine operation, however, duct burner operation will not be unlimited, (i.e. operating the duct burner at its full output [119Mw] would be limited to 1388 hours per year).

Electric Interconnection

Spring Canyon Energy will interconnect with the PacifiCorp system at the Mona Switching Station. The Mona Switching Station provides the flexibility to interconnect with any of the station's owners. The station is an open bus and interconnecting with PacifiCorp allows SCEP to conduct business with LADWP or Deseret Electric Co-op without any additional transmission cost. A request for interconnection was submitted to PacifiCorp in October 2001 and final resolution is expected soon. ABB was retained to perform an Interconnection Fatal Flaw Analysis, which is included in Section 4. Based on the ABB analysis and discussions with PacifiCorp, it is anticipated that the interconnection will require a minimal upgrade. The ABB analysis can be summarized as follows:

> There are five power transfer scenarios (directions) from the Mona Switching Station. Of these, four are unconstrained or require minimal upgrades allowing SCEP access to multiple markets.

SCEP has retained Navigant Consulting to assist with the final discussions with PacifiCorp.

Water

SCEP has completed the negotiations of the purchase of 551 acre-feet (gross) of water rights with 167 (gross) acre-feet under contract and 384 acre-feet awaiting final signature. A letter provided by Jody Williams, esq., of Kruse, Landa & Maycock date July 1, 2002, describes in detail the process for gaining state approvals to transfer the purchased water rights to the project location. This letter is attached in Section 8. The transfer is expected without delay, however, there will be a reduction in the allowed used by up to 44% in order to shift from an agricultural use to an industrial use. Assuming the maximum reduction action is taken by Utah, a minimum of 308 acre-feet of water will be available to SCEP each year. A letter provided by Waldron Engineering is also attached in Section 8 which provides an analysis of the SCEP water needs under a "worst case" scenario concluding that at most, SCEP will need no more than 270 acre-feet (net) of water per year.

Rezoning

SCEP obtained the final action of Juab County confirming the rezoning of the property on July 1, 2002. The ordinance establishing the industrial zoning classification is attached in Section 9.

Other Permits

A detailed analysis provided by SWCA dated June 20, 2002 is attached in Section 10, and describes the additional permits required for construction. The approvals for which Spring Canyon Energy has yet to apply are routinely issued in Utah for natural gas pipeline and electrical transmission lines.

Next Steps

All of the fundamental aspects of project development have been completed or are viewed to be readily achievable. This includes the air permit, the electrical interconnect, property ownership and rezoning, fuel transport and access easements. At this stage of development, SCEP has turn its primary focus to securing short, medium and long-term power off-take or tolling agreements from credit worthy entities. SCEP has recently completed an analysis of the higher priced power markets accessible from the Mona Switching Station, which was conducted by Navigant Consulting. This analysis provides the strategy for achieving financeable power contracts. It is anticipated that this effort will be the critical path towards the close of construction financing which may be achieved in early 2003.

Simultaneous with the effort to secure off-take customers, SCEP has determined that it is the appropriate time to seek a strategic partner(s) with financial and operational strengths that has the ability to assist with the completion of development and the desire to invest a significant portion of the equity that will be required.

This preliminary offering memorandum is intended to provide a current view of the opportunity provided by Spring Canyon Energy LLC. Detailed information can be provided upon the execution of a confidentiality agreement. For further information, contact:

Mr. F. David Graeber
USA Power Partners LLC
10440 North Central Expressway, Suite 1400
Dallas, Texas 75231
(214) 520-8177
e-mail: fdgraeber@usapowerpartners.com

WALDRON ENGINEERING, INC.
37 Industrial Drive
Exeter, NH 03833

Telephone (603) 772-7153
Facsimile (603) 772-7693

July 1, 2002

Mr Dave Graeber
10440 N. Central Expressway, Suite 1400
Dallas, TX 75231

Subject: 112-02; Spring Canyon Energy, performance analysis and alternative equipment configuration.

Dear Dave:

The current Spring Canyon design philosophy has been to apply what is known in the industry as a "2 on 1" combined cycle equipment arrangement. Current performance data and site layouts reflect this design. The attached performance data sheet and curves are for a GE type 207FA combined cycle with duct firing and inlet chilling.

An alternative design approach that is also widely utilized in the industry is the "1 on 1" combined cycle equipment arrangement wherein a single gas turbine is matched with it's own dedicated steam turbine and related equipment. This approach facilitates such matters as dispatching a plant at part load conditions, and phased construction for future expansion. There are currently a number of sites under construction wherein the design utilizes up to four 1 x 1 GT/ST equipment trains.

When a project requires at least two gas turbines, the 2 x 1 GT/ST configuration is a natural choice to consider for several reasons. The primary advantages of a 2 on 1 configuration over two 1 x 1 equipment trains are primarily twofold. a) Slightly better output and heat rate due to the larger scale steam turbine serving two gas turbines, and b) reduced cost through the economy of scale also associated with the application of larger steam cycle equipment. A disadvantage of the 2 x 1 arrangement is seen if the plant is dispatched at part load, where more efficient turn-down operation can be obtained from two 1 x 1 trains. One can envision that at 50% load, the two 1 x 1 equipment train plant can operate at peak efficiency by operating only one GT/ST train. On the other hand, a 2 x 1 plant at half load will be operating off of peak, at a greatly reduced partial load steam turbine condition.

An additional benefit of the 1 x 1 configuration is that the smaller steam turbine may generally allow slightly faster startup times from a cold condition. However, this advantage is somewhat less important because there are means to keep equipment in hot or warm standby condition to avoid lengthy start up times regardless of equipment size.

In evaluating the key differences between a 2 x 1 configuration plant and one containing two 1 x 1 trains, the following information will give one an idea of the comparative performance and cost differentials:

Configuration	Output	Heat Rate	Plant Cost
One 2 x 1 Design	Base	Base	Base
Two 1 x 1 Trains	- 0.75%	+ 0.85%	+ 6% to 8%

Using this information, one could expect the rating for a plant comprised of two 1 x 1 trains to be approximately 525,400 kW at 7520 btu/kWh HHV at 59F with duct firing and chillers off. The comparable 2 x 1 plant rating is 529,400 kW at 7457 btu/kWh HHV, determined per the attached performance data sheet.

The following order of magnitude costs have been estimated for a 2 x 1 type plant configuration, exclusive of switchyard and transmisson:

EPC Contract Detail		
Civil Work, Foundations & Buildings	$5,543,990	
Power Island Equipment	$108,927,290	
Balance of Plant, Mechanical	$96,248,500	
Balance of Plant, Electrical & Control	$15,445,000	
Direct Cost Subtotal		$226,164,780
Spare Parts	$11,031,040	
Engineering & Construction Management	$15,831,535	
Contractor's OH & Profit	$10,576,751	
Contingency	$22,616,478	
Logistics & Freight	$992,794	
Tax Allowance	$0	
Total EPC Contract		$287,213,376

Based on this, one might expect a two 1 x 1 train plant to be 6 to 8 percent higher in direct cost than that shown for the 2 x 1 configuration, or about $13.6 mm to $18.1 mm. These additional costs are primarily associated with duplication of the steam cycle equipment, piping, valves and foundations in the two 1 x 1 train design.

Please give me a call if you would like us to develop more specific information for a 1 x 1 GT/ST design approach.

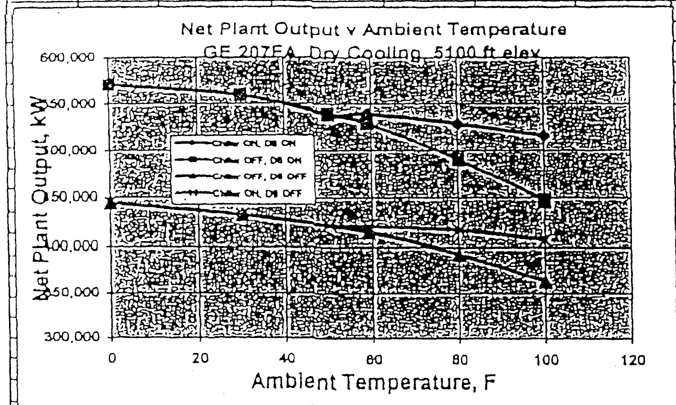
Sincerely,

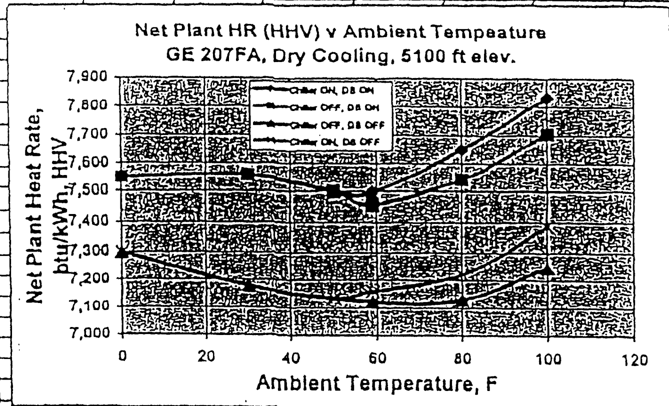
R.F. Racine

Raymond F. Racine, PE
Project Manager
603-772-7153, Ext 118
email: rfr@waldroneng.com

Amb T, F	GT Inlet, F	GT kW	ST kW	Aux kW	GT Fuel, mmbtu/hr HHV	DB Fuel, mmbtu/hr HHV	Plant Net kW	Net HR, btu/kWh HHV
Chiller ON (59F - 100F), Duct Burner ON								
0	0	316,000	259,900	5,200	3,243	1,066	570,700	7,550
30	30	300,800	263,700	5,400	3,104	1,122	559,100	7,558
50	50	288,200	255,900	5,400	3,010	1,030	538,700	7,500
59	50	288,200	258,000	7,170	3,010	1,030	539,030	7,496
80	50	288,200	249,600	8,640	3,010	1,037	529,160	7,649
100	50	288,200	237,800	9,800	3,010	1,033	516,200	7,832
Chiller OFF, and Duct Burner ON								
0	0	316,000	259,900	5,200	3,243	1,066	570,700	7,550
30	30	300,800	263,700	5,400	3,104	1,122	559,100	7,558
50	50	288,200	255,900	5,400	3,010	1,030	538,700	7,500
59	59	281,400	253,400	5,400	2,953	994	529,400	7,457
80	80	260,600	235,100	5,200	2,797	903	490,500	7,543
100	100	239,000	212,500	5,000	2,628	812	446,500	7,704
Chiller OFF and Duct Burner OFF								
0	0	316,000	132,000	3,700	3,243	Off	444,300	7,299
30	30	300,800	135,300	3,700	3,104	Off	432,400	7,178
59	59	281,400	137,000	3,700	2,953	Off	414,700	7,122
80	80	260,600	135,500	3,800	2,797	Off	392,300	7,130
100	100	239,000	127,500	3,800	2,628	Off	362,700	7,245
Chiller ON and Duct Burner OFF								
0	0	316,000	132,000	3,700	3,243	Off	444,300	7,299
30	30	300,800	135,300	3,700	3,104	Off	432,400	7,178
50	50	288,200	138,900	5,130	3,010	Off	421,970	7,134
59	50	288,200	137,750	5,470	3,010	Off	420,480	7,159
80	50	288,200	136,000	7,240	3,010	Off	416,960	7,220
100	50	288,200	128,000	8,600	3,010	Off	407,600	7,385

From Vol. #1





Waldron Engineering Inc
37 Industrial Drive
Exeter, NH 03833

MARKET ASSESSMENT

FOR USA POWER'S

SPRING CANYON ENERGY PROJECT

PRIVILEGED AND CONFIDENTIAL

Prepared For

USA POWER

Prepared By

Navigant™
CONSULTING, INC.

P19

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EXECUTIVE SUMMARY

Over the past three years, utilities, power marketers, developers, and consumers have endured a "wild-ride" in the electricity markets of the Western Electricity Coordinating Council (WECC). The region has gone from a position in which industry participants, state regulators, and the Federal Energy Regulatory Committee (FERC) believed that the market was resource deficient, spurring a flurry of potential new projects to the Enron debacle, charges of market manipulation, and a credit crunch on developers. This, in turn, has resulted in thousands of megawatts of proposed power projects drying-up across the West. This cycle of events threatens the WECC with additional capacity shortages in the near term if more proposed units are not placed in service or if electricity demand grows at a pace exceeding expectations.

With this background, USA Power, Inc. (USA Power), through Spring Canyon Energy, LLC (Spring Canyon Energy), is proposing the development and construction of a 450 MW natural gas-fired generation unit near the Mona Substation in central Utah. From this location the Spring Canyon Energy Project (Project) will be able to access power markets in a minimum of seven western states. Transmission limitations across PacifiCorp's grid may limit the amount of Spring Canyon Energy Project's output that could reach certain regions. Despite the potential transmission issue there are multiple opportunities for this Project to deliver competitively priced power to specific Market Areas with a need for new resources within the planning horizon of this study.

As discussed in the body of this report, there are two primary target markets, Utah and Southern California, and a secondary market, Northern Nevada. A third opportunity may involve the opportunity for displacement arrangements with PacifiCorp or one or more of its trading partners. Although this report did not evaluate the Colorado or Idaho Market Areas, these may also be potential markets. Based on resource availability and transmission constraints, the Southern Nevada and Arizona Market Areas should be afforded less priority than the other Market Areas analyzed in this study.

Market Area Opportunities

The following is a brief summary of potential opportunities for each Market Area.

Utah Market Area

The Utah Market Area should be a prime target for the output of the Spring Canyon Energy Project. Whether the output is used for sales to Utah Market Area electric utilities or as displacement for transactions with entities located outside of the Utah Market Area the Spring Canyon Energy Project's first market focus should be Utah.

Within the Utah Market Area there are four entities that provide viable opportunities, PacifiCorp, UAMPS, UMPA and Deseret. Obviously, due to the size and the ownership of transmission facilities, the largest opportunity may be with PacifiCorp. PacifiCorp has a number of long-term summer purchases and sales; a summary of these is included in Appendix C (note these are for system-wide and include several purchases and sales for portions of the PacifiCorp system located outside of the Utah Market Area). Based upon existing resources in the Utah Market Area and the expected load growth for the region, PacifiCorp should be looking for additional capacity in the Utah Market Area and the Spring Canyon Energy Project would provide fuel diversity and operational flexibility for the Utah Market Area. Opportunities with PacifiCorp include diversity programs, base load resource, displacement opportunities, operational flexibility, and access to newer technology with a superior heat rate and lower operation and maintenance costs and reduce emissions.

UAMPS provides an interesting opportunity, as collectively the UAMP Members are involved in multiple projects (generation and transmission). The exact level of interest that UAMPS (and its Members may have) is unknown, but for the same reason as PacifiCorp (load growth and diversity) UAMPS is a viable market opportunity.

UMPA and Deseret may also be opportunities in the Utah Market Area; however, based on the size of their loads and existing resources, they warrant attention after PacifiCorp and UAMPS.

Southern California Market Area

The Southern California Market Area provides the other prime market for the Spring Canyon Energy Project. Via the Intermountain DC transmission line, the Project could serve the deep Southern California Market Area. This option becomes even more viable if Southern California municipal utilities were participants and/or purchasers of the output from the Spring Canyon Energy Project. The Members of the Southern California Public Power Agency (SCPPA) own the Intermountain DC transmission line and facilities; the unused capacity on this system (400-500 MW) could be utilized to move output from Spring Canyon to the Southern California Market Area. SCPPA and the Intermountain Power Authority (IPA) are currently examining the options for a third unit at Intermountain; the Spring Canyon Project may prove a viable, diverse fuel option for the owners of IPA. The SCPPA Members represent over 7,500 MW of load and the SCPPA Members do not have the same credit issues plaguing California's investor-owned utilities.

Northern Nevada Market Area

The Northern Nevada Market Area is a very viable market due to its deficiency of in-area generation. However, due to the limited transmission import capability from Utah to the Nevada Market Area, it is unlikely that a large portion of the output from the Spring Canyon Energy Project could be targeted to the Northern Nevada Market Area. However, regardless of the transmission limitations there are two distinct marketing opportunities: (1) if or when the Falcon-Gondor facilities are constructed, 155 MW of new import capability from Utah would present itself; and (2) opportunities for spot-market sales when transmission capacity is available on the Gondor transmission line.

Southern Nevada Market Area

The Southern Nevada Market Area has sufficient in-area generation and transmission facilities that also lead-into and out-of the market area. Nevada Power Company is a major purchaser of electricity; however, it is not likely a high-priority market for this Project due to inability to obtain transmission access. The best path to the Southern Nevada Market Area for the Spring Canyon Energy Project is the TOT 2C transmission path, which is currently fully subscribed by PacifiCorp. Hence, the only current mechanism to serve the Southern Nevada Market Area would be via some form of exchange with PacifiCorp for access onto TOT 2C.

Arizona Market Area

PacifiCorp has long-term sales to the Arizona Market Area that utilize most, if not all, of the transmission capacity available between Utah and the Arizona Market Areas. Therefore, the best opportunity for the Spring Canyon Energy Project to serve the Arizona Market Area would be via an arrangement with PacifiCorp to displace some of its sales to the Arizona Market Area.

USA Power, through Spring Canyon Energy, is developing a 450 MW base-load natural gas-fired combined cycle power generation facility known as the Spring Canyon Energy Project (Project). The Project will be located in the heart of the WECC and adjacent to the major power market in Utah, Salt Lake City. The Project's close proximity (less than one mile) to the Mona Switching Station will provide access to electricity markets in Arizona, Nevada, southern California, Idaho, Colorado, and the Pacific Northwest.

USA Power has retained the services of Navigant Consulting, Inc. (Navigant Consulting) to assist with a variety of issues relating to the Project, including the development of this Report focusing on a market assessment of specific markets available for the Project. This Report is intended to identify specific markets or utilities that USA Power may then target for the Project (long-term contracts or ownership). The information in this Report may be used by USA Power to initiate discussions and/or negotiations with viable entities in the Market Areas discussed (or entities wishing to serve those Market Areas) for short, medium, and/or long-term contracts.

This report provides USA Power with an assessment of all the Market Areas identified in Navigant Consulting's agreed upon scope of services, including Utah, northern Nevada, southern Nevada, southern California, and Arizona. The purpose of this Report is to assess the ability to access various Market Areas and determine potential current and future energy requirements for the various Market Areas. Specifically, in providing this assessment, this Report provides a discussion of the following elements for each Market Area:

- Description of Market Area
- Market Area Loads and Load Forecast
- Generating Resources (existing and planned)
- Transmission Ownership and Capability
- Load/Resource Balance
- Regional Legislative and Regulatory Issues

A key aspect of Navigant Consulting's preliminary market assessment focuses on the components necessary to develop a load/resource balance for each of the identified Market Areas. Because USA Power is a generator located in the WECC, the development of a load/resource balance will assist in determining the magnitude of surpluses or deficiencies in resources as it is matched against projected load requirements. This approach will assist USA Power in determining potential markets and partners for the Spring Canyon Energy Project.

In addition to the discussion of each of the identified Market Areas, this report also includes an overview of WECC region-wide issues (Section 2). Following the discussion of the individual Market Areas (Sections 3 through 7) is a discussion of energy prices in the WECC (Section 8). Finally this report includes Appendices relevant to the study, Appendix A contains summary tables of the load/resource balances for each region; Appendix B contains a series of transmission maps for the market areas; and Appendix C is a summary of PacifiCorp long-term power sales and purchases.

The power market in the WECC, formerly the Western System Coordination Council (WSCC), has experienced multiple dramatic changes in the past several years. This section discusses how of the turmoil in the western electricity market may impact the Spring Canyon Energy Project and the appearance of the future of the WECC.

Throughout the early and mid-1990s the Federal Energy Regulatory Commission (FERC) embarked on an effort to introduce competition to the wholesale electricity market. FERC began to allow for market-based pricing of wholesale electricity provided that the seller complied with several requirements (e.g. lack of market power and offering of non-discriminatory transmission access to own transmission facilities). A number of states across the nation began to develop programs to bring electricity competition to the retail electricity market.

On March 31, 1998 California became the first state in the Union to offer retail choice to all customers of California's three largest investor-owned utilities. California also created two quasi-governmental organizations to oversee and run the retail electricity market, the California Power Exchange (PX) and the California Independent System Operator (CAISO). For the first few years everything appeared to be functioning well for California as wholesale rates remained in the mid-teens to low-30 dollars per megawatt hour (MWh). However, California's PX prices began to impact the prices elsewhere in the WSCC, moving the prices of the Pacific Northwest and the Desert Southwest closer together and closer to the California price for wholesale electricity.

In the summer of 1999, indications of problems with the California marketplace began to emerge, when wholesale prices stayed above $30/MWh for May through December, peaking at around $50/MWh. Then, in April 2000, the price of electricity skyrocketed to over $100/MWh in California, pulling the rest of the WSCC into the stratospheric price range as well. Prices ultimately peaked in January 2001 at over $500/MWh.

By the time FERC intervened (June 2001), the California PX was bankrupt, the Pacific Gas and Electric Company (PG&E) had filed for bankruptcy, and several Pacific Northwest utilities and the Southern California Edison Company (SCE) were teetering on bankruptcy. The dramatic increases in prices are attributable to various factors, including faulty market rules in California, supply-demand imbalances, robust energy requirement growth combined with little or no new energy infrastructure, alleged market manipulation by energy companies and traders, and slow response time by state and federal regulators.

In response to requests from California and the Pacific Northwest, on June 19, 2001, FERC imposed "soft" price caps on wholesale power sold in the WSCC-region. FERC imposed these soft caps in an effort to stabilize electricity costs and to also provide the CAISO with time to develop a new market design. The caps are in effect twenty-four hours a day, seven days a week, and apply to all eleven states in the WECC. (For discussions of the price caps please see Section 8 - Prices). Almost immediately after the FERC Order was issued, WSCC energy prices returned to pre-2000 levels. The price cap Order expires at midnight on October 1, 2002.

The CAISO, California Senators, and many other politicians representing western states have urged FERC to extend the price caps. However, FERC Chairman Wood has indicated that he would like to see an end to the price caps to allow market forces the opportunity to work in the WECC region. Therefore, it remains to be seen whether the FERC-imposed price caps will expire on October 1, 2002, or not. It is extremely unlikely that the current price caps will still be in place when the Project comes online. On the other hand, it is conceivable that some form of close market monitoring and controls will be imposed for the WECC by FERC.

Several factors over the past 18 months, including regulatory uncertainty, FERC price caps, balance sheet concerns, and credit worthiness of certain purchasers, have resulted in a major halt on proposed new generation projects in the WECC. In fact, in the five market areas studied, over 16,000 MW of projects that were proposed as late as summer 2001 have been cancelled. In addition, the future of several thousand MW of other proposed projects is uncertain.

The recession of 2001, extremely mild weather during summer 2001, and major conservation programs and potential other reasons lead to a depressed energy requirement for 2001. Most regions within the WECC saw 2001 peak loads and energy requirements drop in 2001 vis-à-vis 2000. It is not expected that the summer 2001 requirements will become the norm. Rather, it is anticipated that 2001 was a unique set of circumstances that are yet to be fully understood and that when the economy recovers, a return to normal weather patterns, and the conservation fervor dies down, electricity consumption will again grow at a steady rate throughout the WECC. Growth is expected to grow more rapidly in Southern Nevada, Arizona and Utah as compared to California.

Prior to the implementation of the price caps, FERC had taken other steps to spur development of new energy infrastructure projects and wholesale competition. Following is a brief discussion of two of these initiatives that impact the WECC-region: Regional Transmission Organizations (RTOs) and generator interconnection standards.

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Regional Transmission Organizations

In an effort to provide open, non-discriminatory access to the nation's electric transmission grid, and to provide information transparency, FERC is advocating the creation of RTOs. Of interest to this Project is the proposal for the creation of RTO West, which is currently being developed by nine WECC utilities (Avista, Bonneville Power Administration, Idaho Power Company, Montana Power Company, Nevada Power Company, PacifiCorp, Portland General Electric, Puget Sound Energy, and Sierra Pacific Power Company). RTO West, as a non-profit organization with an independent board of directors, will operate a singe control area for all of the participating transmission owners. Depending on the final structure and implementation of RTO West, it may be possible for a generator like the Project (or an entity purchasing the output of the Project) to move the output anywhere within the RTO West region by paying a single "license plate" transmission rate (depending on availability of transmission). In addition, as RTO West and the other proposed RTOs in the WECC (including the CAISO) develop interactions with each other ("seams issues"), the "license plate" approach could extend throughout the WECC.

Generator Interconnection Standards

For the past few years FERC has also been seeking a way to provide incentives for the development and construction of new infrastructure projects (generation and transmission) in the West. On April 24, 2002, FERC issued a Notice of Proposed Rulemaking (NOPR) addressing the standardization of generator interconnection. FERC is proposing a pro-forma interconnection agreement and a set of interconnection procedures that would form the basis for all generator interconnections.

This NOPR addresses issues that have been common stumbling blocks encountered by generators requesting interconnections including excessive delays and high interconnection costs. As proposed, the NOPR provides generators with an assurance that construction and system improvements would be completed on schedule or liquidated damages would be owed (by the utility) to the generator. Furthermore, all rights, responsibilities, and obligations, including legal boilerplate such as liability, insurance and indemnification are specified in the pro forma *Standard Generator Interconnection and Operating Agreement* and the *Standard Generator Interconnection Procedures* (both included in the April 24, 2002 NOPR).

Also of extreme importance in the NOPR is the provision that generators are to be granted credits for contributions made in support of electric transmission development. In summary, generators would have credits to use on the transmission providers transmission system for transmission service equal to the amount of capital (plus interest) provided by the generator for transmission system improvements.

One of the prime market areas for the Spring Canyon Energy Project is Utah. As the Project is to be located in Utah, the simplest market for the output of the Project will be that state. This section of the report defines the Utah power market, discusses the current and forecasted future energy requirements for the market, examines the available resources to serve the Utah Market Area, considers proposed new resources for the market area, projects an overall 10-year load/resource balance, and briefly discusses relevant political and regulatory issues for Utah.

In performing the marketplace assessment for the various market areas, a key component was the development of a load/resource balance for that marketplace. The first step in determining the resource balance between electricity demand (customer use and required reserves) and electricity resources (generation capacity and import capability) is to clearly define the market area.

The Utah Market Area is served by one investor-owned utility (PacifiCorp), forty-two municipal utilities, and four major rural electric cooperatives (Coops). For PacifiCorp, the Utah Market Area also includes a small portion of southern Idaho and southwestern Wyoming. This is illustrated in Appendix B of this report on the bubble map showing the *Pace Control Area (Utah Main System)*. For the purpose of this study, references to the PacifiCorp load will include all loads served by PacifiCorp in Utah, southern Idaho, and southwestern Wyoming.

The municipal utilities in Utah are in one of two major joint power agencies (JPAs), UAMPS and UMPA. UAMPS has a total of 42 members, 36 of which are municipal utilities within the state of Utah (the other 6 members are in other Western States); UAMPS also claims the Central Utah Conservancy District as a Member, as well as five other local governmental utilities located outside the State. For the purpose of this study UAMPS' load *only* includes the 36 Utah municipal systems. UMPA has 6 members, all of which are municipal utilities within the state.

All four of the major co-ops in Utah (Dixie Escalanta Rural Electric Association, Flowell Electric Association, Garkane Energy Cooperative, and Moon Lake Electric Association) are Members of the Deseret Generation and Transmission Cooperative (Deseret). Deseret also has Members located in surrounding states.

LOADS

For 2002, the electric utilities in the Utah Market Area are estimated to have a non-coincidental[1] summer peak load of 4,794 MW. Table 3-1, shown below, summarizes the projected peak load for the market area. The Utah Market Area peak load shown in this analysis represents the sum of the individual utility peak loads and does not consider diversity among utility systems.

Table 3-1
Electric Utilities in
The Utah Market Area

Utility	2002 Peak (MW)
PacifiCorp	3,820
UAMPS	603
UMPA	206
Co-ops	165
Total	4,794

Load Forecast

To estimate the load requirements for the Utah Market Area, a 10-year forecast was complied, based on information contained in the PacifiCorp RAMPP-6 Report (Resource and Market Planning Program) as part of PacifiCorp's Integrated Resource Planning (IRP) process. The WSCC 10-year Coordinated Plan Summary, information available from the Utah Public Service Commission (Utah PSC) supplemented the information provided in the RAMPP-6 Report. Energy Information Administration (EIA) data, and the 2002 Electrical World Directory of Electric Power Producers were also utilized to substantiate or fill-in information not available from other sources.

The RAMPP-6 Report and all published data from PacifiCorp treats the load and resources for PacifiCorp on a six state, system-wide basis, making it difficult to specifically identify the load and load growth within the Utah Market Area. However, at the request of the Utah PUC, the RAMPP-6 Report includes two special interest cases concerning the potential load growth within the area that constitutes this report's Utah Market Area.

The two cases run by PacifiCorp included a base case with an expected average annual load growth in the Utah Market Area of 2.2 percent and an accelerated load growth of 3.3 percent. For this study, PacifiCorp base case is utilized. In addition, this load growth was also used for all of the utilities in Utah.

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[1] The non-coincidental peak is the sum of the estimated peak load for all of the utilities in the Utah Market Area The coincidental peak load for the Utah Market Area is slightly lower.

PacifiCorp load forecast for 2002 is 3,820 MW, which represents approximately 80 percent of the load in the Utah Market Area. It is estimated that this load will grow to approximately 4,760 MW by 2011 (pursuant to PacifiCorp's RAMPP-6 report). The two municipal JPAs have a combined estimated peak load of 809 MW in 2002 (UAMPS 602 MW and UMPA 206 MW). This represents approximately 17 percent of the total load for the Utah Market Area. This load is estimated to grow to approximately 1,008 MW, using the same growth factor, by the end of the study period. The co-ops' load in the Utah Market Area is approximately 165 MW, or three percent of the total load, and is expected to grow to approximately 206 MW by 2011.

Resources

The Utah Market Area meets its electric demand through generation projects located within the area and by importing electricity over a robust transmission system that is interconnected with all of the neighboring states at voltages of 230 kV and 345 kV. In addition, the Utah Market Area is a major exporter of power to southern California from the Intermountain Power Project (discussed in more detail below).

Total Utah Market Area generation (including that which is dedicated to serving other markets) is estimated to be 5,219 MW in 2002. Additional generation, totaling 200 MW, is expected to come online in late 2002/2003. In addition, Navigant Consulting estimates that the simultaneous import capability into the Utah Market Area to be approximately 2200 MW. Therefore the total capacity (generation resources and transmission import capability) is estimated to be 7,499 MW in 2002.

Market Area Generation

Coal plants dominate the Utah Market Area, the four largest coal plants (Intermountain, Hunter, Huntington, and Bonanza) account for almost 81 percent of all generation projects in the Utah Market Area. Table 3-2 summarizes the resource composition of the existing resource base.

Table 3-2
Composition of Generation for
Utah Market Area

Fuel Type	Capacity (MW)	Percent of Total
Hydro	247	5%
Natural Gas/Oil	419	8%
Coal	4,486	86%
Renewables	12	0%
Other	55	1%
Total	5,219	100%

As mentioned above, the Utah Market Area is a major exporter to California from the Intermountain Power Project (IPP). Southern California municipal utilities have an approximately 75 percent entitlement to the 1660 MW IPP or approximately 1244 MW. The remainder of IPP entitlements belongs to electric utilities in Utah (including PacifiCorp, municipal utilities and cooperatives). However, when looking at the total Utah Market Area generation it is important to note that, at *most* times, at least 75 percent of the output of IPP is moving southwest to California.

Transmission Import Capability

The transmission system in Utah is principally owned and operated by PacifiCorp and is interconnected with California, Nevada, Idaho, Wyoming, Colorado, and Arizona. PacifiCorp utilizes the extensive Utah transmission system to move power throughout the state and to make purchases from other utilities in the neighboring states. PacifiCorp operates the transmission facilities interconnecting Utah with all of the above states with the exception of California. The transmission to California is owned by the members of SCPPA and operated by the Los Angeles Department of Water and Power (LADWP). The non-simultaneous import capability for the Utah Market Area is 5,035 MW[2]. For the purposes of this study, Navigant Consulting has estimated the simultaneous import capability to be 2,200 MW (a much more detailed transmission study would be required to calculate the true simultaneous import capability). Table 3-3 illustrates the non-simultaneous transfer capability on the major transmission paths in the Market Area.

Table 3-3
Non-Simultaneous Transmission Import Capability
Into the Utah Market Area

Transmission Path	Capacity (MW)
Eastern Nevada-Utah (Gondor)	150
Intermountain-Mona	1,400
TOT 2B1 (Siguard-Glen Canyon)	300
TOT 2B2 (Pinto-Four Corners)	600
TOT 2C (PacifiCorp-NPC)	300
Bonanza West (Bonanza-Mona)	645
Path C (Southern Idaho-Northern Utah)	1,500
Vernal-Ashley	140

The Project is planning to interconnect into the PacifiCorp transmission system at the Mona Substation. The Mona substation has three owners, PacifiCorp, IPA, and Deseret.

[2] The non-simultaneous import capability is the sum of the ratings of all of the transmission facilities into the Market Area and is not a representation of the amount of power that at any one-time can flow into the Market Area.

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From the Mona substation all three entities have the ability to move power on their respective transmission systems. The diagram in Appendix B illustrates the available transmission capacity (ATC) and non-simultaneous transmission line rating (NSR) for the transmission facilities in Utah and interconnections with the other market areas for this study.[3]

Accordingly sufficient ATC is available to move all of the output from the SCEP onto the main PacifiCorp transmission grid in Utah (designated as PACE on the map in Appendix B). This provides an opportunity for output from the Project to reach all loads within the Utah Market Area; however there are limitations at all of the borders of the PacifiCorp transmission grid. At Mona there is also the ability to move 338 MW on the Deseret transmission system and 623 MW to the IPA transmission system. Again there are some ATC limitations on the both Deseret and IPA transmission systems. The Deseret transmission facilities are between Mona and Bonanza. The IPA transmission system includes: (1) the two 345-kV transmission lines between IPA and Mona; (2) the IPA 500-kV DC facilities to southern California; and (3) the IPA-Gondor 230-kV transmission line.

Proposed Generation

Unlike several of the other market areas in this study there has not been a large number of proposed new generation projects in Utah. In fact, other than the two new simple cycle natural gas-fired units currently under construction by PacifiCorp it is unlikely that more than one or two of the other projects shown on Table 3-4 will come online within the next several years.

Table 3-4
Proposed Generation Projects for
The Utah Market Area

Company	Project	Status	Fuel Type	Proposed Online Date	Capacity (MW)
Deseret Power	Bonanza	Starting App. Process	Gas	Jan-04	80
USA Power	Spring Canyon	Application Process	Gas	Jun-04	550
Intermountain Power	Intermountain 3	Press Release Only	Coal	Jun-07	900
PacifiCorp	West Ridge II	Under Construction	Gas	Jun-02	80
Tasco Engineering	Stockton Bar	Press Release Only	Wind	Jan-05	25
Intermountain Power	Intermountain Upgrades	Press Release Only	Coal	Dec-03	220
PacifiCorp	Gadsby Peaker	Under Construction	Gas	Sep-02	120
Payson City/UAMPS	Payson	Press Release Only	NA	Jan-11	128
Total					2,103

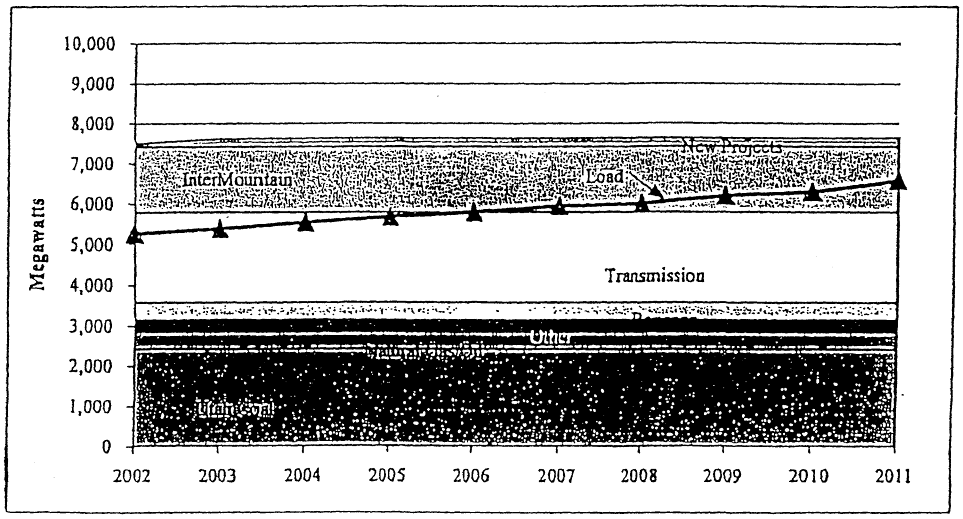
[3] The ATC shown on the diagram corresponds to stated ATC on the PacifiCorp OASIS for the period of June 2002 to May 2003 and represents available firm transmission rights.

* Information based on California Energy Commission's database of Proposed Power Plants with the WSCC – Updated February 27, 2002

LOAD/RESOURCE BALANCE

Figure 3-1 provides an illustration of the projected load/resource balance for the 10-year period based on the information discussed above.

Figure 3-1
Estimated Loads and Resources
For the Utah Market Area
(2002 through 2011)



As the above figure illustrates the Utah Market Area generation (excluding IPP) is not sufficient to meet the energy requirements in any year in the study period. Rather, the Utah Market Area is dependent on transmission imports and/or IPP generation to meet the demand for each year and both imports and IPP generation for the years 2005 forward. As mentioned earlier in this Report, at least a 75 percent entitlement of IPP output is shipped to California via the Intermountain DC transmission line. Therefore, there is a current and future demand for additional in-area generation resources for the Utah Market Area. Without the development of new generation projects in the Utah Market Area, it will become even more dependent on imports. This provides a strong argument for the inclusion of the Spring Canyon Energy Project into the Utah Market Area resource portfolio.

POLITICAL AND REGULATORY ISSUES

In 2001 Utah Governor Mike Leavitt (R) unveiled his Utah Energy Policy, which states *"Utah will have reliable, affordable, sustainable, clean energy"*. The Policy conjectures that

Utah's current estimate of additional electrical requirements over the next ten years should be between 1800 and 3100 MW. Governor Leavitt recognizes that such a growing need necessitates new generation to be built within the state To reach such goals, the Governor commits to a streamlined and fast-tracked regulatory process as part of the agenda, creating a single point of review – the Department of Environmental Quality. He also created, in an executive order, the Energy Coordinate Council, which is charged with implementing Utah's energy policy.

SECTION 4 SOUTHERN CALIFORNIA MARKET AREA

The Southern California Market Area is the largest Market Area (in terms of customers and load) of this market assessment. The Southern California Market Area stretches from the border of the PG&E/SCE service territory in the north to Mexico in the south. SCE is the dominate utility in the region serving almost 60 percent of the approximately 33,000 MW load. However, the San Diego Gas and Electric Company (SDG&E) and the Los Angeles Department of Water and Power (LADWP) are also large utilities within the Southern California Market Area.

The Southern California Market Area has a significant amount of existing infrastructure both generation and transmission; however, the Southern California Market Area is very dependent on imports from other regions to meet its load requirements. Many of the existing generation units in southern California are 30 plus years old and a significant portion of the transmission into the region is either committed to long-term agreements or is utilized to import Southern California Market Area utilities' resources located out-of-state. Due to the large load and age of the plants, there are numerous projects proposed for the Southern California Market Area; however, over the course of the last 18 months several of these have been cancelled or at least put on hold. This has occurred for several reasons including regulatory uncertainty, attempted renegotiation of contracts by the State of California, financial uncertainty of California investor-owned utilities, low loads in 2001 to name a few reasons.

It is important to note that while the Utah Market Area is not geographically located next to the Southern California Market Area, there is a direct electric connection between the two. Therefore, under the right terms and conditions (or ownership) generation from the Spring Canyon Energy Project could readily access the massive Southern California Market Area.

LOADS

In 2001, the 17 electric utilities in the Southern California Market Area are estimated to have a non-coincidental summer peak load of 33,082 MW. Table 4-1, shown below, provides information regarding each utility's anticipated 2002 summer peak load (note that the load for three cities of Azusa, Banning, and Colton is shown as a single number). The Southern California Market Area peak load considered by this analysis represents the sum of the individual utility peak loads, not necessarily the coincidental peak load.

Table 4-1
Electric Utilities in
The Southern California Market Area

Utility	2002 Peak (MW)
Southern California Edison	19,469
San Diego Gas and Electric	3,660
Anaheim Public Utilities Department	608
Burbank Public Service Department	281
California Department of Water Resources	1,059
Glendale Public Service Department	312
Imperial Irrigation District	735
Los Angeles Department of Water and Power	5,486
Metropolitan Water District of So. California	297
Pasadena Water and Power Department	286
Riverside Utilities	494
Cities of Azusa, Banning and Colton	167
Vernon Municipal Light Department	202
Anza Electric Cooperative	9
City of Needles	16
Total	33,082

Load Forecast

To estimate the demand for energy, NCI developed a ten-year summer peak demand forecast for each of the utilities within the Southern California Market Area. The forecast was based in part on historical information regarding the peak demand of each utility, as well as information available from the California Energy Commission and the CAISO. Overall, these sources indicate that the expected load growth for the Southern California Market Area is projected to increase at an average annual rate of 1.7 percent for the forecast period. (Individual utility growth rates may be found in Appendix A.)

The two IOUs (SCE and SDG&E) that provide electric services within the Southern California Market Area serve approximately 70 percent of load with SCE meeting 60 percent and SDG&E 10 percent. SCE's load is estimated at 19,469 MW for 2002 and will grow to 22,860 MW by 2011. SDG&E's load is estimated at 3,660 MW for 2002 and will grow to 4,611 MW by 2011.

The Governmental Entities in the Southern California Market Area include municipal utilities, irrigation districts, water districts, and government agencies (California Department of Water Resources). In total, the Governmental Entities served are estimated to have a combined peak demand of 9,853 MW, or 30 percent of the Southern California Market Area for 2002 This load is estimated to grow to 11,034 by 2011. The largest municipal utility is LADWP, which has an estimated peak load of 5,486 MW for

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2002 that will grow to 6,000 MW by 2011. LADWP accounts for 55 percent of the non-IOU load and 16.5 percent of the total Southern California Market Area load.

For the purposes of this analysis, and consistent with the WSCC standard reserve requirements, this analysis assumes a seven percent reserve margin requirement for Southern California Market Area throughout the 10-year forecast period.

RESOURCES

Resources available to meet demand requirements in the Southern California Market Area include 1) Market Area generation, and 2) transmission import capability. Existing Market Area generation is estimated to be approximately 28,332 MW in 2002. Additional generation of approximately 6,845 MW (including 500 MW in 2002) is projected to come online by 2004, increasing the total Southern California Market Area generation to 35,177 MW. The simultaneous transmission import capability is estimated to be approximately 13,000 MW throughout the 10-year forecast period.

Market Area Generation

Natural gas-fired units dominate existing Southern California Market Area generation. These units account for almost 20,000 MW or approximately 70 percent of the existing generation in the Southern California Market Area. Table 4-2 summarizes the composition of the generation in the Southern California Market Area.

Table 4-2
Composition of Generation for
The Southern California Market Area

Fuel Type	Capacity (MW)	Percent of Total
Hydro	4,273	15%
Natural Gas/Oil	19,994	69%
Geothermal	36	0%
Nuclear	2,150	8%
Other	2,379	8%
Total	28,832	100%

Transmission Import Capability

Transmission imports into the Southern California Market Area play an extremely crucial role in meeting the needs of the region. Imports are necessary to "keep the lights on" in the Southern California Market Area. In addition, Southern California Market Area utilities import a large amount of generation located in Nevada, Arizona, New Mexico, and Utah through the transmission system.

Transmission imports to the Southern California Market Area are governed by the Southern California Import Transmission (SCIT) nomogram. The maximum non-simultaneous import capability into the Market Area is 18,564 MW. However, the SCIT nomogram currently limits simultaneous imports to approximately 13,000 MW, depending on multiple system conditions (including all units at Palo Verde being online and all transmission facilities being in-service and the amount of transmission flowing on the EOR transmission system).

There are several different transmission paths that feed southern California including transmission lines from northern California (Path 26), the Pacific Northwest (PDCI), the Desert Southwest (WOR), Utah region (Intermountain), and Mexico. Table 4-3 below identifies all of the major transmission paths into the Southern California Market Area.

Table 4-3
Non-Simultaneous Transmission Import Capability
Into the Southern California Market Area

Transmission Path	Capacity (MW)
West of River	10,118
Path 26	3,000
Pacific DC Intertie	3,100
Intermountain DC	1,920
Mexico Intertie	408

While the opportunity exists to move power into the Southern California Market Area from several directions and across several paths, the pertinent path for this study is the Intermountain Transmission Line.

As discussed in the Utah Market Area, the IPP has a 1,920 MW DC line that stretches from central Utah to the Adelanto substation in southern California. The line is operated by LADWP with ownership by LADWP and the other SCPPA members. Table 4-4 below summarizes the ownership percentage on this transmission path.

Table 4-4
Transmission Ownership on
The Intermountain Transmission Line

Company/Agency	Ownership
LADWP	60%
City of Anaheim	18%
City of Riverside	10%
City of Pasadena	6%
City of Burbank	5%
City of Glendale	2%

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As discussed in the Utah Market Area portion of this report, the Southern California municipal utilities have an entitlement of approximately 75 percent or 1,244 of the IPP. They utilize the Intermountain Transmission Line to bring that power to the Southern California Market Area. Without knowing specifically what other resources (e.g. long-term agreements, spot purchases) are using the facilities, there may be 600 MW (or more) of unutilized capacity on the Intermountain Transmission Line.

Proposed Generation

Over 12,000 MW of new generation is currently proposed for the Southern California Market Area. The proposed projects are almost exclusively natural gas-fired generation. The currently proposed projects are illustrated in Table 4-5.

Table 4-5
Proposed Generation Projects for
The Southern California Market Area

Company	Project	Status	Fuel Type	Online Date	Capacity (MW)
Cal Energy	Salton Sea VI	Starting App. Process	Geothermal	Oct-04	180
City of Burbank	Magnolia Modernization	App. Under Review	Gas	Mar-04	250
Edison International	Sunrise Power Phase II	Under Construction	Gas	Aug-03	265
Inland Grp & Constellation	High Desert	Under Construction	Gas	Jul-03	720
Sempra	Palomar Energy (Escondido)	App. Under Review	Gas	Jan-05	500
GWF	Lemoore (Henrietta)	App. Under Review	Gas	Aug-02	91
Duke	Avenal	App. Under Review	Gas	Jan-05	600
Texaco	South Star I	App. Under Review	N/A	Sep-03	100
Berry Petroleum	Taft	Starting App. Process	Gas	Jul-03	86
FPL	FPL Tesla	App. Under Review	Gas	Feb-05	1,120
Summit Energy Group	Blythe	Under Construction	Gas	Apr-03	520
Calpeak	San Diego Mission	Regulatory Appvl Rc'd	Gas	Jun-02	50
Sempra/OXY	Elk Hills CC	Under Construction	Gas	Apr-03	570
Calpeak	El Cajon	Regulatory Appvl Rc'd	Gas	Apr-02	50
Summit Energy Group	Blythe II	Starting App. Process	Gas	May-04	520
Calpeak	Midway Buttonwillow	App. Under Review	Gas	Jan-03	49
Calpine	Pastoria	Under Construction	Gas	Jan-03	750
NRG & Dynergy	El Segundo	App. Under Review	Gas	May-04	630
Calpine	Otay Mesa	Under Construction	Gas	Jul-03	510
LADWP	Scattergood	Press Release Only	Gas	Jan-11	50
AES	Huntington Beach Mod.	Under Construction	Gas	Apr-02	450
LADWP	Haynes	Press Release Only	Gas	Jan-11	50
LADWP	Valley	App Under Review	Gas	Sep-03	500
City of Vernon	Malburg	App. Under Review	Gas	Sep-03	120
ARCO Western Energy	Midway-Sunset	Regulatory Appvl Rc'd	Gas	Jul-04	500
PG&E NEG	La Paloma Phase I	Under Construction	Gas	Aug-02	521
PG&E NEG	La Paloma Phase II	Under Construction	Gas	Oct-02	522
Duke	Morro Bay	App Under Review	Gas	May-04	1,200
AES	Mountainview	Under Construction	Gas	Jun-03	1,056
BP	Arco Watson	Starting App. Process	Gas	Aug-03	96
Total					12,626

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* Information based on California Energy Commission's database of Proposed Power Plants with the WSCC – Updated February 27, 2002

Approximately 5,900 MW of generation is currently listed as under construction; however, this number can be misleading, as some of the projects on the table above represent repowering of existing units, net additions are uncertain. In addition, a number of projects replace an existing unit or unit outages forced by environmental restrictions. Also, more than 12,000 MW of proposed generation within California have been cancelled within the past 18 months. Therefore, although there appears to be a significant amount of new capacity proposed, the net impact on the overall load/resource balance is very difficult to forecast.

Further complicating the Southern California Market Area is a need to take into account the amount of generating capacity that is out-of-service, whether it be for scheduled maintenance work, forced outages, or even lack of emission credits. Although this item has not been identified separately in any of the other Market Areas in the load/resource balance analysis, the magnitude of the outages and their respective impact on the Southern California Market Areas are of crucial importance.

To accommodate such an adjustment for the Southern California Market Area, NCI reviewed power plant outage information provided by CAISO to derive an outage adjustment factor for this analysis. Although it is important to note that plant outages vary throughout the year, especially during winter and spring periods as a result of planned maintenance activities, the outage factor of 18 percent used for this study is aimed to provide a conservative estimate of readily available generation resources. For the Southern California Market Area, this translates into approximately 5,000 MW of the total available generation capacity being out-of-service at anytime in 2002.

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LOAD/RESOURCE BALANCE

Figure 4-1 provides an illustration of the projected load/resource balance for the 10-year period.

Figure 4-1
Estimated Loads and Resources
For the Southern California Market Area
(2002 through 2011)

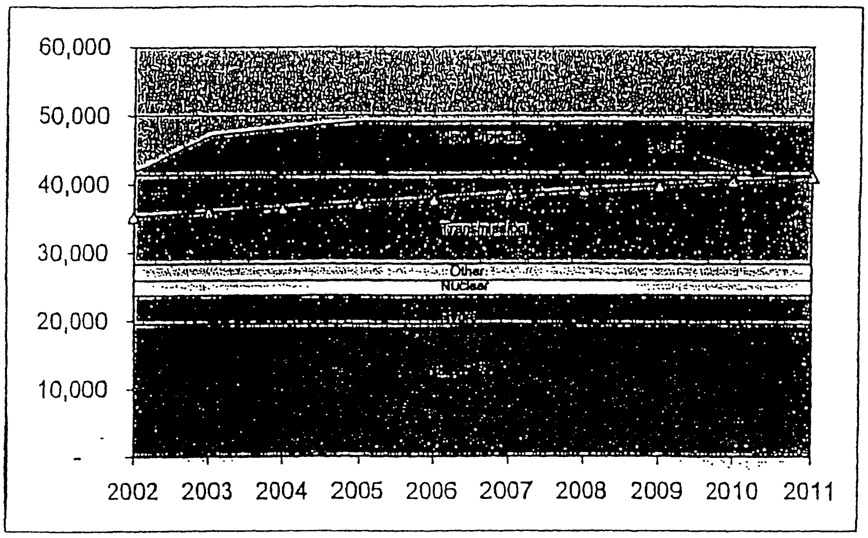

Figure 4.1 illustrates the Southern California Market Area dependence on transmission to meet its energy requirements. This is expected as Southern California Market Area Utilities have made major investment into generation (and associated transmission infrastructure) in Nevada, Arizona, Utah, and New Mexico. The figure also illustrates that even with the massive transmission infrastructure serving the Southern California Market Area additional new generation is need by the end of the planning horizon of this Report. The dependence on imports and the availability of capacity on the Intermountain DC system provides an excellent opportunity for the Spring Canyon Energy Project to reach and serve the Southern California Market Area.

POLITICAL AND REGULATORY ISSUES

Governor Gray Davis has been attempting to stabilize the chaotic energy markets in California, which has been the epicenter for the western markets dysfunction. In his 2002 State of the State address, Governor Davis reiterated his commitment to building new power plants. His staff and resource agencies have been working to renegotiate power contracts (entered into during the crises in 2001), to lessen both length of contract

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and cost per MW of power. They have had some success to this end. Governor Davis is also relentlessly pursuing refunds from FERC.

The Governor and his departments are renewing their conservation efforts through the "Flex Your Power Campaign." The amount of MW in proposed generation has been cut in half due to the regulatory uncertainties in California, and has probably been compounded with the passage of SB 39XX, which grants the California Public Utilities Commission (CPUC) regulatory jurisdiction over private generating facilities in California. Thus, conservation efforts will be critical this summer, due to the less-than-expected new generation online this summer. The CAISO's summer forecast has suggested that as long as conservation efforts continue, the summer will progress without forced outages.

The state is in constant regulatory flux. Many issues remain unresolved (e.g. procurement, direct access, exit fees, transmission upgrades, creditworthiness of the IOUs), which makes the climate extremely unfavorable for new generation projects.

Several key pieces of legislation have been passed in the last two years pertaining to electricity generation and procurement.

AB 1X: Designated the California Department of Water Resources (DWR) as the state agency responsible for procuring power for the financially-defunct IOUs.

AB 6X: Prevents the state's IOUs from divesting assets until at least 2006.

SB 5X: Allocates funds for energy conservation.

SB 39XX: Allows the CPUC to regulate generating facilities in the state.

Several pending pieces of legislation should be considered in any assessment of the market:

AB 57: Requires that the IOUs develop a procurement plan that will be operational by December 31, 2002.

AB 117: Facilitates community aggregation (a modified version of the suspended direct access option)

AB 1529: Attempts to streamline transmission siting

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AB 2062: Overhauls the state's energy regulatory bodies to create one body out of the seven that now regulate energy issues in California.

Regulatory Matters

The CPUC is inundated with weighty, high-stakes issues that have primarily grown out of the California energy crisis.

The key proceedings that will affect the regulatory environment are: The IOU procurement proceeding, the direct access/exit fee proceeding, the rate stabilization proceeding, and the CPUC's role in the PG&E reorganization.

The procurement proceeding is moving forward. SCE has proposed that the state partner with the utilities as a guarantor on power purchases until the utilities are credit worthy. The CPUC has responded favorably to this suggestion, and has designated SCE as the coordinator of this proposal.

The Direct Access/Exit Fee proceeding has encountered some set backs, with errors emerging in the base case models. DWR has subsequently pushed back the hearing dates to mid-June. This may ultimately delay final resolution until the end of 2002.

The rate stabilization proceeding has made significant progress, having determined a revenue requirement, rate agreement and service agreements. PG&E continues to protest the service agreement that it has with DWR, but the CPUC voted to move forward, despite the $80 million in contest.

The bankruptcy court judge has accepted PG&E's disclosure statement for its reorganization. The creditor committee will be voting to choose one of the two plans in June. This vote is critical in determining PG&E's ability to procure power for its customers.

Transmission upgrades are not abundant. The CPUC has attempted to force PG&E's hand on Path 15, but the utility has continued to work with private investors (namely TransElect) to upgrade the line.

Finally, the CAISO has submitted a new market design to FERC, which resembles the FERC plan to standardize markets.

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SECTION 5 NORTHERN NEVADA MARKET AREA

This section focuses on the northern Nevada Market Area, which is dominated by Sierra Pacific Power Company (Sierra Pacific). This is a viable market area for the Spring Canyon Energy Project, as northern Nevada has historically been a net importer of electricity. Transmission limitations from Utah restrict the amount of power that could flow into the Northern Nevada Market Area from the Spring Canyon Energy Project; however, the proposed Falcon-Gondor 345-kV transmission line, when completed, will greatly enhance the Northern Nevada Market Area's ability to import from Utah.

The Northern Nevada Market Area, in addition to Sierra Pacific, includes one small municipal utility (City of Fallon) and two co-ops (Wells and Mount Wheeler). The Sierra Pacific service territory includes most of northern Nevada and a small portion of eastern California around Lake Tahoe.

LOADS

Combined, the four electric utilities in the Northern Nevada Market Area are estimated to have a summer 2002 peak load of approximately 1,818 MW. Table 5-1 shows the summary of the estimated 2002 peak load for the Northern Nevada Market Area. The peak load shown represents the sum of the individual utility peaks loads and does not consider diversity among utility systems.

Table 5-1
Electric Utilities in the
Northern Nevada Market Area

Utility	2002 Peak MW
Sierra Pacific	1,657
Wells Rural Electric Cooperative	102
Mount Wheeler Power	44
Fallon Municipal Electric System	15
Total	1,818

Load Forecast

The load forecast for the Northern Nevada Market Area was derived from data sources that included Sierra Pacific's *Comprehensive Energy Plan*, a study by the Nevada Electric Energy Policy Committee and internal Navigant Consulting forecasts The Sierra Pacific load forecast for 2002 is 1,657 MW and it is estimated that the load will increase by 2 6 percent through 2005 and 1 percent after that, for an average annual increase of 1 5 percent over the 10-year planning horizon and a total load estimate of 1,900 MW in

2011. The estimated load for the three small utilities begins at approximately 161 MW and grows to 181 MW by 2011.

For this analysis, a reserve margin of seven percent, consistent with WECC standards, is used for the Northern Nevada Market Area.

RESOURCES

The Northern Nevada Market Area is highly dependent on transmission imports to meet the load requirements. In-area generation is incapable of meeting Northern Nevada Market Area demand in 2002. In fact, the largest project in the Northern Nevada Market Area, Valmy coal plant (532 MW), is half-owned by Sierra Pacific with the Idaho Power Company owning the other half. The Valmy plant constitutes 28 percent of the total generation capacity in the Northern Nevada Market Area. The Northern Nevada Market Area imports power from the Pacific Northwest, Idaho, and Utah. The interconnection with California (PG&E) does not provide the ability for transfers between the regions.

Existing Northern Nevada Market Area generation is estimated to be 1,898 MW, with an additional 12 MW of geothermal capacity due online in mid-2002. The estimated transmission import capability into the Northern Nevada Market Area is 650 MW, providing a total resource base of 2,560 MW.

Market Area Generation

As mentioned previously, the largest project in the Market Area is the Valmy coal plant. Other large projects include the Tracy (402 MW) and Fort Churchill (226 MW) gas-fired units owned by Sierra Pacific. Additionally, the Tri-Center Naniwa Energy Project in Storey County, a 360 MW project came online in late 2001. Table 5-2 summarizes the resource composition in the Northern Nevada Market Area.

Table 5-2
Composition of Generation for
The Northern Nevada Market Area
(2002)

Fuel Type	Capacity (MW)	Percent of Total
Coal	621	33%
Natural Gas	1,002	52%
Hydro	11	1%
Diesel/Fuel Oil	**72**	4%
Geothermal	204	11%
Total	1,910	100%

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Transmission Import Capability

The Northern Nevada Market Area is interconnected with California, Oregon, Idaho, and Utah via separate transmission facilities. Sierra Pacific has historically used its transmission infrastructure to import power to meet 50 percent of its demand. The weakest interconnection is with California and PG&E via the summit 115-kV facilities. During normal business operations there are no transfers with California via this transmission path.

The other three interconnections are discussed in greater detail below. Non-simultaneous, they provide Sierra Pacific with import capability of 1,045 MW (see Table 5-3). Sierra Pacific operates its system with a simultaneous import capability of between 650 and 700 MW.

Table 5-3
Non-Simultaneous Transmission Import Capability
Into the Northern Nevada Market Area

Transmission Path	Capacity (MW)
Alturas Transmission Project	300
Eastern Nevada-Utah (Gondor)	245
Idaho-Sierra	500

The Reno-Alturas Transmission Project (Alturas) is a 345-kV transmission line that runs from Sierra Pacific's Bordertown substation to Bonneville Power Administration's transmission system at Hilltop, in northern California. The Alturas Project has a WSCC rating of 300 MW. Sierra Pacific's Gonder substation is interconnected with both the Intermountain and Pavant substations in Utah, at 230-kV. Maximum non-simultaneous transfer capacity from East to West is 245 MW. The Idaho-Sierra path connects Sierra Pacific with Idaho Power Co. at the Midpoint connection in Idaho. Maximum non-simultaneous transfer capacity of this 345-kV system is 500 MW.

In addition, Sierra Pacific plans to build a 345-kV transmission line between its Falcon and Gondor substations. This would increase the transfer capability from Utah to Nevada from 245 MW to 400 MW. This transmission project would likely increase the overall simultaneous import capability of the northern Nevada Market Area by 150 to 200 MW.

Proposed Generation

Two additional large natural gas-fired generation units are currently under review at the Nevada Public Utilities Commission. The first is a 540 MW unit being proposed by Duke that would be located in Washoe County. The second project is a 480 MW unit being proposed by Newmont Mining, located in Elko County. Table 5-4 lists all known proposed projects for the northern Nevada Market Area.

Table 5-4
Proposed Generation Projects for
The Northern Nevada Market Area

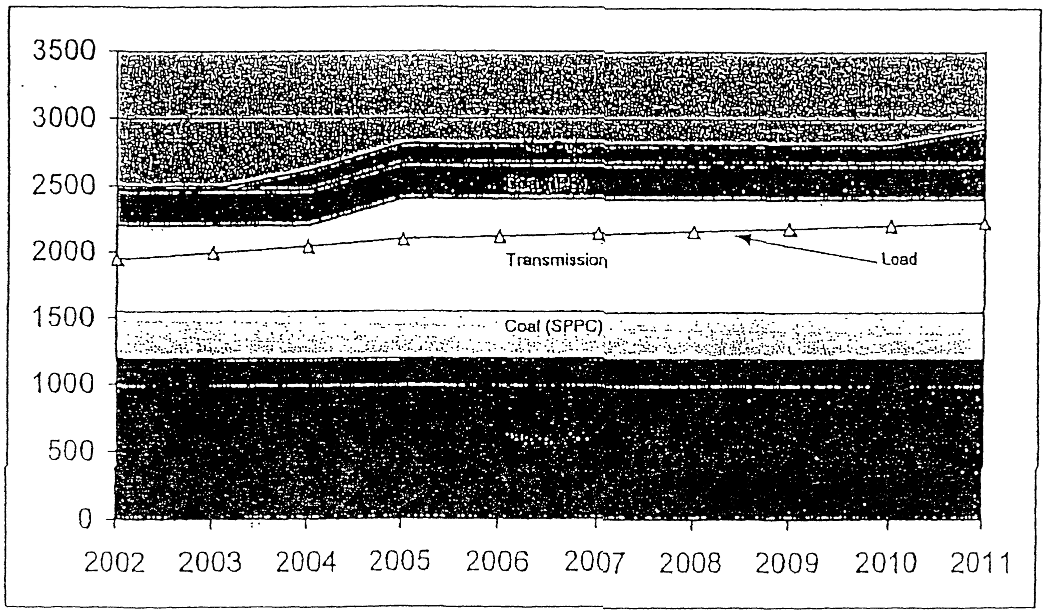
Company	Project	Status	Fuel Type	Online Date	Capacity (MW)
EOPT	EOPT TRI	Regulatory Approval Rec'd	NA	Dec-02	30
Mt. Wheeler Power	Rye patch	Under Construction	Geothermal	Apr-02	12
Duke Energy NA	Washoe Power Plant	Application Under Review	Gas	June-04	540
Newmont Mining	Boulder Valley	Application Under Review	Gas	Jan-11	480
Total					1,062

* Information based on California Energy Commission's database of Proposed Power Plants with the WSCC – Updated February 27, 2002

LOAD/RESOURCE BALANCE

The 10-year load/resource balance for the Northern Nevada Market Area is illustrated in Figure 5-1 below

Figure 5-1
Estimated Loads and Resources
For the Northern Nevada Market Area
(2002 through 2011)



The Northern Nevada Market Area is currently dependent on transmission imports to meet a significant portion of its peak load (at least 25 to 30 percent). This reliance on

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imports will continue through the 10-year study period. The Northern Nevada Market Area lacks sufficient generation to meet its energy requirements. In addition, there are very few projects proposed to increase in-area generation. Rather, the Northern Nevada Market Area looks to continue to rely (and increase its reliance) on imports to meet its energy requirements. This reliance coupled with the proposed Falcon-Gondor Transmission Project may provide the Spring Canyon Energy Project with an opportunity for providing needed capacity to the Northern Nevada Market Area.

POLITICAL AND REGULATORY ISSUES

The state of Nevada has faced and is facing several of the same challenges that impacted California in 2000 and 2001. Both of the large investor-owned utilities in Nevada (Sierra Pacific and Nevada Power) are net purchasers of electricity. Both are also operating companies of Sierra Pacific Resources. The drastic escalation of electricity prices in the west in 2000 and 2001 resulted in the Nevada companies spending hundreds of millions of dollars on purchases that they had not anticipated. Electric rates were not designed to recover the high costs of the market purchases.

In fact, Nevada Power Company is now on the brink of bankruptcy and it may pull Sierra Pacific Resources (and therefore Sierra Pacific Power) with it. A detailed synopsis of Nevada Power Company's financial woes is included in Section 6.

SECTION 6 SOUTHERN NEVADA MARKET AREA

The Southern Nevada Market Area boasts the fastest growing demand for energy in this study and within the entire WECC. In fact, annual electricity demand growth is expected to remain between 5 and 6 percent for the foreseeable future. The financially troubled Nevada Power Company is the dominant utility in the Southern Nevada Market Area; other utilities include the Colorado River Commission (CRC), Valley Electric Association, Boulder City, and six other small local electric utilities.

The Southern Nevada Market Area has a tremendous amount of electric infrastructure, both generation units and transmission facilities. However, most of these do not belong to the utilities located within the Southern Nevada Market Area and are not utilized to serve Southern Nevada Market Area load. The two largest projects in Nevada and the Southern Nevada Market Area, the massive Hoover Dam hydroelectric facilities (Hoover) (1,951 MW) and the Mohave coal facilities (Mohave) (1,580 MW) are primarily owned or allocated to utilities outside of the Southern Nevada Market Area. (This is discussed in greater detail below.) In addition, a number of the proposed projects for the Southern Nevada Market Area are targeting not only the fast growing local load but also the load in Southern California.

LOADS

For the summer peak load of 2002, the estimated load in the Southern Nevada Market Area is 4,872 MW. Table 6-1, shown below summarizes the projected peak load by utility for the Southern Nevada Market Area. The peak load represented is a sum of the individual non-coincidental peak load.

Table 6-1
Electric Utilities in
The Southern Nevada Market Area

Utility	2002 Peak (MW)
Nevada Power Company	4,311
Colorado River Commission	324
Valley Electric Co-op	94
Other governmental utilities	143
Total	4,872

Load Forecast

The 10-year load estimated forecast for the Southern Nevada Market Area was derived from data sources that included the WSCC 10-year Coordinated Plan Summary, a study by the Nevada Electric Energy Policy Committee, and internal Navigant Consulting forecasts. All of these sources estimate that the total load in the Southern Nevada Market Area will continue to grow at a greater than 5 percent rate for the next 10 years.

The Nevada Power Company load forecast for 2002 is 4,311 MW, and it is estimated that the load will increase to 7,100 MW by the end of the 10-year planning horizon. The load for the rest of the Southern Nevada Market Area is estimated at 561 MW for 2002 growing to 668 MW by 2011. A reserve margin of seven percent is used for the Southern Nevada Market Area.

RESOURCES

The Southern Nevada Market Area does not lack resources. However, most of the resources are earmarked for other regions. The Nevada Power Company meets a large portion of its energy requirements via power purchases, which explains why Nevada Power Company is in a financial dilemma as a result of the price spikes in 2000 and 2001. The decision by the Nevada PUC to limit recovery of the power purchase costs (see discussion below) has left Nevada Power Company with a shortfall of over 1,000 MW of required power for the summer of 2002.

Existing Southern Nevada Market Area generation is 6,660 MW for 2002. The northern portion of the massive East-of-River (EOR) transmission system moves power into the Southern Nevada Market Area (from Arizona and New Mexico) and the northern portion of the West-of-River (WOR) transmission system moves power out of the Southern Nevada Market Area (to Southern California). For the purposes of this study Navigant Consulting has assumed a simultaneous import capability into the Southern Nevada Market Area of 4,000 MW. Therefore the total capacity of the Southern Nevada Market Area (generation resources and transmission import capability) is estimated to be 10,660 MW.

Market Area Generation

The Southern Nevada Market Area existing generation portfolio is almost equally divided between coal projects (2,185 MW), natural gas-fired projects (2,321 MW), and a hydroelectric project (1,951 MW). Table 6-2 summaries the resource composition of the existing Southern Nevada Market Area.

Table 6-2
Composition of Generation for
The Southern Nevada Market Area
(2002)

Fuel Type	Capacity (MW)	Percent of Total
Coal	2,185	33%
Natural Gas	2,321	35%
Hydro	1,951	29%
Diesel/Fuel Oil	202	3%
Geothermal	0	0%
Total	6,660	100%

As mentioned above, most of the output from Hoover and Mohave does not stay in the Southern Nevada Market Area. For Hoover only 20 3 percent or 397 MW out of the 1,951 MW are allocated to utilities in the Southern Nevada Market Area (377 MW for the CRC and 20 MW for Boulder City). Only the Nevada Power Company has an ownership interest in the Mohave coal-project, and its ownership is 14 percent (221 MW). On these two projects alone only 598 MW out of 3,531 MW are owned or entitled to Southern Nevada Market Area load serving entities.

Transmission Import Capability

The massive WOR and EOR transmission systems dominate the southern Nevada high voltage transmission facilities. The WOR facilities connect southern Nevada with southern California, while the EOR system connects Arizona to both southern Nevada and southern California. In addition to these large transmission paths, southern Nevada is also interconnected to Utah via the TOT 2C (Red Butte-Harry Allen) 345-kV transmission facilities. A summary of the facilities and the non-simultaneous import capability is provided in Table 6-3.

Table 6-3
Non-Simultaneous Transmission Import Capability
Into the Southern Nevada Market Area

Transmission Path	Capacity (MW)
TOT 2C (PacifiCorp-NPC)	300
Northern EOR	
Navajo-McCollough	1,422
Moekopi-Eldorado	1,555
Liberty Mead	450
Westwing-Mead	1,300
Total Northern (EOR)	4,727

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For the most part, the transmission system into and out of southern Nevada serves as a mechanism to move power from Arizona and New Mexico to the large southern California marketplace. In fact, the Nevada Power Company only has a 371 MW ownership on the EOR system and no ownership on the WOR system.

Proposed Generation

The Southern Nevada Market Area has been a hotbed for proposed new generation projects. As illustrated in Table 6-4, over 7,000 MW of new projects are still planned. However, in the past 12 months, over 1,300 MW of proposed new projects in the Southern Nevada Market Area have be cancelled and Navigant Consulting anticipates that this number will continued to grow. Of the proposed new projects, 6,600 MW are natural-gas fired projects, 345 MW are wind projects, and 400 MW is a proposed new hydroelectric project.

Table 6-4
Proposed Generation Projects for
The Southern Nevada Market

Company	Project	Status	Fuel Type	Online Date	Capacity (MW)
M&N Wind Power	Shoshone Mt. Wind III	Application Under Review	Wind	June-05	85
Duke Energy NA	Moapa Energy Facility I	Under Construction	Gas	Apr-03	600
Reliant	Arrow Canyon	Application Under Review	Gas	Apr-04	575
PG&E NEG	Meadow Valley	Application Under Review	Gas	Jan-11	1,191
Sempra/Reliant	Copper Mt. (El Dorado II)	Regulatory Approval Rec'd	Gas	Mar-05	500
Mirant	Apex Industrial I	Under Construction	Gas	Mar-03	550
Duke Energy NA	Moapa Energy Facility II	Under Construction	Gas	Jun-03	600
M&N Wind Power	Table Mt. Wind Project	Application Under Review	Wind	Dec-03	90
Pinnacle West	Silver Hawk	Application Under Review	Gas	May-04	570
Cogentrix	Toquop Energy	Application Under Review	Gas	Oct-04	1,100
Reliant	Bighorn CC	Under Construction	Gas	Sep-03	580
Blue Diamond Pwr	Red Rock Canyon	Application Under Review	Hydro	Dec-05	400
M&N Wind Power	Shoshone Mt. Wind I	Application Under Review	Wind	Jun-03	85
M&N Wind Power	Shoshone Mt. Wind II	Application Under Review	Wind	Jun-04	85
Overton Pwr Distr.	Tortoise Power Plant	Application Under Review	Gas	Jan-11	100
Black Hills	Las Vegas Cogen II	Under Construction	Gas	Sep-02	230
Total					7,341

* Information based on California Energy Commission's database of Proposed Power Plants with the WSCC – Updated February 27, 2002

LOAD/RESOURCE BALANCE

Figure 6-1 provides an illustration of the projected load/resource balance for the 10-year period.

Figure 6-1
Estimated Loads and Resources
For the Southern Nevada Market Area
(2002 through 2011)

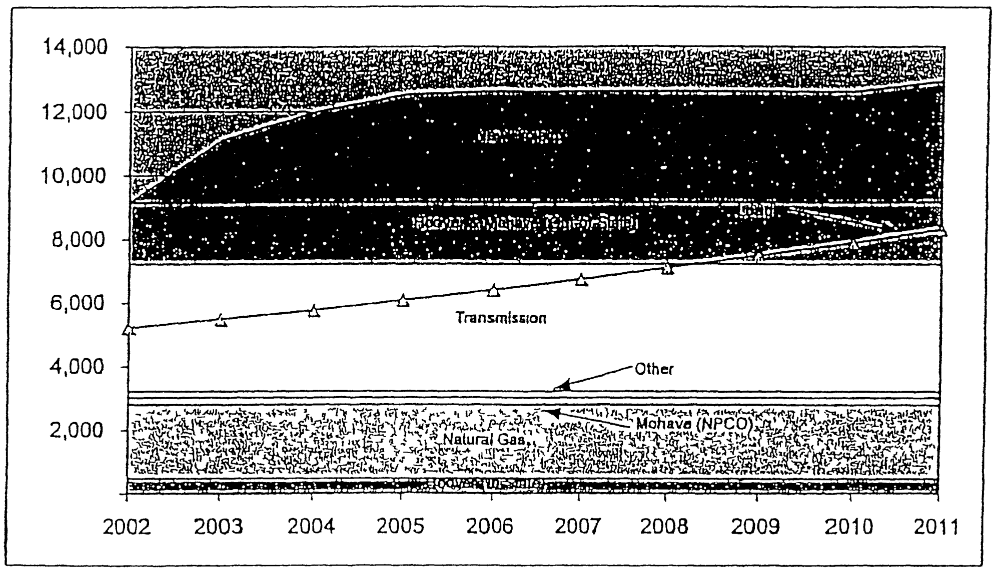

Figure 6-1 shows that with proposed new projects, transmission imports and exports out-of-Market Area there is substantial resources to meet the needs of the Southern Nevada Market Area. Without the new projects the Southern Nevada Market Area is dependent on imports from other regions; however, the NPC is an owner in resources located in other Desert Southwest states and it utilizes the transmission system to bring those resources home.

POLITICAL AND REGULATORY ISSUES

On December 6, 2001, the Nevada Governor, Kenny Guinn (R), announced that three power plants under construction in Southern Nevada would increase generating capacity by 2800 MW, with a total investment of $1 7 billion. Governor Guinn was instrumental in securing cooling water for the plants, and in exchange the generators will guarantee that 25 percent of production is delivered within the Nevada state lines

The major regulatory issue facing the Southern Nevada Market Area is the financial instability of Nevada Power Company, which is also leading to uncertainty regarding reliability for the summer of 2002 The following is a brief chronological synopsis of

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Nevada Power Company's efforts to recover costs associated with wholesale power purchases in 2000 and 2001 from their retail electricity customers.

October 1, 2001 – Nevada Power Company files a General Rate Case Nevada PUC. The filing, the first general rate filing since 1993, seeks an overall three percent increase for operating costs Under existing rules, Nevada Power is required to take a two-phased approach to resetting energy policy and electric rates. The general rate case, phase one, is the beginning of a six-month public filing process before any rates are changed on April 1, 2002. Phase one will provide a detailed look at the company's facility additions (nearly $1 billion since 1993), and all incurred expenses including capital costs.

November 30, 2001 – Nevada Power Company files a request with the Nevada PUC to recover the actual costs for wholesale power and fuel it purchased for customers during the height of the energy crisis. The request seeks to increase rates approximately $307 million (21 percent). These rates are expected to remain in place for three years.

December 5, 2001 - Nevada Power Company and Sierra Pacific Power file formal complaints with the Federal Energy Regulatory Commission seeking a reduction in future prices on contracts they entered into to serve their customers during the height of the energy crisis.

March 27, 2002 - The Nevada PUC issues a decision to cut Nevada Power's general rate increase request. Nevada Power had originally filed the request on October 1, 2001, separate from its pending request for recovery of deferred energy expenses incurred during the peak months of 2001. The company had initially requested a $42 million increase, but later revised that to $23 million to account for customer growth and other adjustments. The Nevada PUC ordered a $43 million rate decrease for the utility company, focusing mostly on rate of return, depreciation, and other financial and accounting issues

April 1, 2002 – The Nevada PUC voted to allow Nevada Power Company to recover, over three years, $485 million out of the $922 million of deferred energy costs it incurred during the peak months of 2001 through a rate change effective April 1, 2002

April 4, 2002 - Union Bank of California confirmed its line of credit to Sierra Pacific Resources' two utility operations, Nevada Power and Sierra Pacific Power, a decision that provides liquidity to the companies As a result, Nevada Power retains its $200 million credit facility and Sierra Pacific Power retains its $150 million credit facility The confirmation follows an announcement by Nevada Power that it will cut capital expenses and seek reconsideration of the deferred energy order by the Nevada PUC of the deferred energy expenses from 2001

The final market area examined in this market assessment is the Arizona Market Area. The load growth in Arizona has been significant over the past two decades and it is anticipated that the Arizona Market Area will continue to grow at a three percent range for the next 10-years. The Arizona Market Area contains a large IOU, Arizona Public Service (APS); a large quasi-municipal utility, the Salt River Project (Salt River); a medium-sized IOU, Tucson Electric Power (Tucson), and 45 other small electric utilities.

Arizona has a fairly large and diverse existing resource base that includes Palo Verde nuclear power plant, the massive Navajo coal project, Glen Canyon hydroelectric facilities, and several other large hydro and natural gas-powered plants. In addition, more than 20,000 MW of proposed new generation is currently planned for the Arizona Market Area; however several of these proposed projects are coming under close and increased scrutiny by the Arizona Commerce Commission, which wants generation built in Arizona to be to serve Arizona load. Finally, the Arizona Market Area contains a massive (and constrained) transmission system that is utilized to move power from the Four Corners region and the large generation units located in the Arizona Market Area to the loads in the Phoenix and Tucson areas and through the state to southern Nevada and southern California.

LOADS

For the summer peak load of 2002, the estimated load in the Arizona Market Area is 15,554 MW. The load is almost evenly distributed between APS (5,495 MW) (35 percent), Salt River (5,152 MW) (33 percent), and the rest of the Arizona Market Area (4,907 MW) (32 percent). Table 7-1, shown below summarizes the projected peak load by major utility for the Arizona Market Area. The peak load represented is a sum of the individual non-coincidental peak load and not necessarily the coincidental peak for the Arizona Market Area.

Table 7-1
Electric Utilities in
The Arizona Market Area

Utility	2002 Peak (MW)
Arizona Public Service	5,495
Tucson Electric Power	1,918
Other IOUs	625
Salt River Project	5,192
Other Governmental Entities	2,324
Total	15,554

Load Forecast

The estimated 10-year load forecast for the Arizona Market Area was derived from data sources that included the WSCC 10-year Coordinated Plan Summary, Arizona Corporation Commission (ACC) data, and individual data from APS and Salt River. It is estimated that on average the load in the Arizona Market Area will grow at 2.8 percent over the forecast period, with growth rates at 3.5 percent in the metropolitan areas.

This forecast estimates that the APS load will begin the forecast period at 5,495 MW and reach 7,489 MW by 2011. Salt River's estimated load will grow from 5,152 MW to 6,157 MW and Tucson's load is estimated at 1,918 MW for 2002 and will grow to approximately 2,614 by 2011. A reserve margin of seven percent is used for the Arizona Market Area.

RESOURCES

The Arizona Market Area has plenty of resources to meet the current load requirements and those in the planning horizon. Existing generation is estimated to be over 16,700 MW with an additional 1,200 expected online in 2002. Arizona Market Area utilities also are major owners in generation resources located in southern Nevada and New Mexico. At the same time, southern California utilities have significant ownership in projects located in Arizona.

Estimating a transmission import capability for the Arizona Market Area is very difficult, as the massive EOR transmission system runs through the state. However, for purposes of this report, it is assumed that the import capability is at least 5,000 MW (this amount may be understating actual capability but overstating practice).

Market Area Generation

Existing Arizona Market Area Generation is approximately one-third natural gas-fired generation (5,673 MW), one-third coal-fired generation (5,311 MW), one-fifth nuclear (3,733 MW), and one-sixth hydroelectric (2,887 MW). Table 7-2 summarizes the composition of the existing generating units in Arizona.

Table 7-2
Composition of Generation for
The Arizona Market Area

Fuel Type	Capacity (MW)	Percent of Total
Coal	5,311	30%
Petroleum	240	1%
Gas	5,678	32%
Nuclear	3,733	21%
Hydroelectric	2,887	16%
Renewable	1	0%
Total	17,850	100%

Transmission Import Capability

The transmission system of Arizona essentially serves two purposes. The first is to move power to the Arizona load in the greater Phoenix area and the second is to move power to the large southern California marketplace (and southern Nevada) via the EOR and WOR transmission system. In addition to the EOR system, Arizona is electrically interconnected with Utah via the TOT 2B Path and with New Mexico via the Four Corners Path. Import capability from Utah to Arizona is limited due to long-term exchanges between APS and PacifiCorp. Table 7-3 highlights the non-simultaneous transfer capability of the transmission paths into Arizona (note that the EOR only in the east-west direction).

Table 7-3
Non-Simultaneous Transmission Import Capability
Into the Arizona Market Area

Transmission Path	Capacity (MW)
EOR	7,550
TOT 2B (Siguard-Glen Canyon)	265
Four Corners	2,325

Proposed Generation

As shown in table 7-4, over 20,300 MW of additional generation is proposed for the Arizona Market Area, some of which is targeting the Southern California and Southern Nevada Market Areas. All but 1,250 MW is proposed to be natural gas-fired generation. As in the Southern California and Southern Nevada Market Areas, the amount that will actually be built and brought in-service is likely to be significantly less. In fact, more than 2,500 MW of proposed generation for the Arizona Market Area has been cancelled in the past year. Furthermore, the ACC is becoming much more stringent on issuing licenses for power projects with an eye on serving load outside of Arizona.

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Table 7-4
Proposed Generation Projects for
The Arizona Market Area

Company	Project	Status	Fuel Type	Online Date	Capacity (MW)
Oasis LLC	Kyrene (Oasis)	Under Construction	Gas	Apr-02	250
PPL Global	Sundance Energy Project 2	Regulatory Appvl Rc'd	Gas	Sep-02	90
APS	Redhawk 3	Regulatory Appvl Rc'd	Gas	Jun-06	530
Reliant	Signal Peak I	Press Release Only	Gas	Apr-04	580
Reliant	Signal Peak II	Press Release Only	Gas	Jan-09	580
SRP	Santan	App Under Review	Gas	May 05	825
Power Dev Ent	Gila Bend	App Under Review	Gas	Jun-04	845
Panda Energy/TECO	Gila River 1	Under Construction	Gas	Apr-03	520
Independent Power Tech	Winchester	Press Release Only	Gas	Jun-07	750
Arizona Elec Power Co op	Apache Station GT #4	App Under Review	Gas/FO	Oct-02	40
Unisource/Bechtel	Springerville Generation I	App. Under Review	Coal	Jun-04	380
PG&E NEG	Harquahala Gen. Station	Under Construction	Gas	Sep-03	1,040
Griffith Energy (PPL&Duke)	Griffith Energy Project	Operational	Gas	Jan-02	650
APS/Calpine	West Phoenix (Phase 2)	Under Construction	Gas	Sep-02	500
APS Reliant	Redhawk 1	Under Construction	Gas	Jan-03	530
APS	Redhawk 4	Regulatory Appvl Rc'd	Gas	Dec-07	530
Duke	Arlington Valley II	Regulatory Appvl Rc'd	Gas	Jul-03	600
APS/Reliant	Redhawk 2	Under Construction	Gas	Jan-03	530
Duke	Arlington Valley 1	Under Construction	Gas	Aug-02	580
SW Power Group II	Bowie I	Regulatory Appvl Rc'd	Gas	Jun 04	500
Panda Energy/TECO	Gila River II	Under Construction	Gas	Apr-03	520
Allegheny	La Paz II	App Under Review	Gas	Apr 05	540
PG&E NEG/Shawn	Tonopah	Press Release Only	Gas	Jun-03	1,100
Maestros Group	Ambos Nogales Generating	Press Release Only	Gas	Jan-07	500
Panda Energy/TECO	Gila River III	Regulatory Appvl Rc'd	Gas	Sep 03	520
Panda Energy/TECO	Gila River IV	Regulatory Appvl Rc'd	Gas	Sep 03	520
Arizona Independent Pwr	White Tank Mountain	Press Release Only	Hydro	Jan 11	1 250
Williams Energy	Littlefield (Beaver Dam)	Press Release Only	Gas	Jun 03	500
Unisource/Bechtel	Springerville Generation II	App Under Review	Coal	Dec-05	380
Allegheny	La Paz I	App Under Review	Gas	Nov 04	540
Sempra Energy Resources	Mesquite Power	Under Construction	Gas	Jan-04	1,265
PPL Global	Sundance Energy Project 1	Under Construction	Gas	Jun 02	450
Powergen LLC	Safford	Press Release Only	Gas	Jan 11	220
Tucson Electric	Vail Generating (Rita Ranch)	App Under Review	Gas	Dec 03	150
SW Power Group II	Bowie II	Regulatory Appvl Rc d	Gas	Dec 05	500
Welton Mohawk	Welton Mohawk (Yuma Enrgy)	App Under Review	Gas	Jun 03	500
Total					20,305

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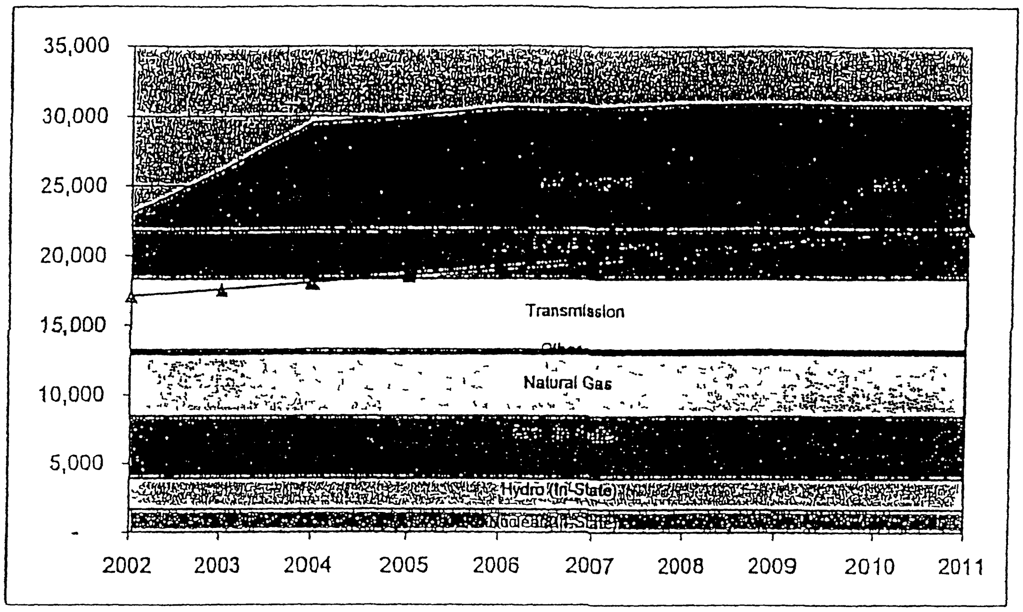
LOAD/RESOURCE BALANCE

As shown in Figure 7-1, there is ample supply to meet the expected load in the Arizona Market Area for the forecast period.

Figure 7-1
Estimated Loads and Resources
For the Arizona Market Area
(2002 through 2011)



The rapid load growth in Arizona will require the construction of new resources in the Arizona Market Area This demand is expected to be met by numerous new projects proposed for the Arizona Market Area. The biggest issue facing the Arizona Market Area is the lack of transmission infrastructure to serve the load growth in the central Arizona region. The limited transmission infrastructure (particularly between Utah and Arizona) limits the opportunities for the Spring Canyon Energy Project to serve the Arizona Market Area, with the exception of potentially augmenting or supplanting the current arrangements between PacifiCorp and APS

POLITICAL AND REGULATORY ISSUES

Arizona Governor Jane Hull is the chair of the Western Governors' Association (WGA). Hull will serve the WGA through August 2002 It was the WGA that helped put pressure on WECC wide price caps and also conducted a study that recommended regional planning for the development and construction of a robust electric transmission system for the WECC. Governor Hull has made public statements about protecting Arizona power from being exported to neighboring states (presumably California).

The 2001-2002 Arizona Legislature did not deal with many energy-related issues

The ACC is active both in placing restrictions on new power plants and encouraging the development of additional transmission facilities.

On May 1, 2002, the ACC approved a Certificate of Environmental Quality for Salt River's expansion of its generation facility at the Santan Generating Facility. A total of 825 new MW will be added through three separate combined cycle natural gas units.

In a 2-1 vote on April 8, 2002, the ACC approved the La Paz Generating Facility proposed for La Paz County in southwestern Arizona. When completed in 2005, the power plant will be capable of delivering 1,080 megawatts to the power grid. Allegheny Energy Supply, the project developer, expects to begin construction on the $540-million natural gas-fired plant later this year. The Arizona Power Plant and Transmission Line Siting Committee on the La Paz site imposed forty conditions on Allegheny for this project. They include:

- Prior to construction of the facility, Allegheny must provide the Commission with a technical study showing that operation of the plant will not compromise the reliable operation of the interconnected transmission system.
- If upgrades to the transmission system are necessary, the study will have to identify the upgrades to be completed before the project commences commercial operations
- Groundwater withdrawal is anticipated to be less than 6,500 acre-feet per year operating at full capacity but the total annual pumping cannot exceed the amount of water spelled out in Arizona Revised Statute §45-440(A).
- Establishment of a monitoring project for ground subsidence and earth fissures. Subsidence is a potential side effect of groundwater pumping Cracks, fissures or dips can form in the surface of the earth because the water deep underground that provided physical support is no longer there
- *Before selling power elsewhere, La Paz Generating Station must first offer* wholesale power to companies serving power to Arizona users
- The plant operators must try to use qualified Arizona contractors and encourage the hiring of qualified local employees
- Allegheny will have to coordinate activities to minimize construction and operational impacts on local wildlife and native vegetation A biologist and archeologist will monitor all ground clearing and construction activities

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- Allegheny must comply with air and water quality standards imposed by the Arizona Department of Environmental Quality and the Arizona Department of Water Resources.

On January 31, 2002, the ACC denied SouthWestern Power Group II's application to build the 1,800 megawatt Toltec Power Station in Eloy, Arizona. The Commissioners said the applicants failed to prove a need for the project and chose the wrong site for a project of this magnitude. The project, approximately eight miles from Picacho Peak, a popular recreation area in the southern Arizona desert, would have generated enough power for a half million people or more, according to testimony. However, according to all three Commissioners, the combination of its location in a sensitive environment and the applicant's failure to adequately address the need issue compelled a "no" vote.

As a part of the market assessment associated with the proposed Spring Canyon Energy Project, Navigant Consulting has provided a general overview and discussion of electricity and natural gas prices within the WECC. This section of the Report provides several illustrations of historical and projected prices at major trading hubs in the western United States. Although Navigant Consulting did not propose to develop specific electricity or natural gas price forecasts for this market assessment, these various price projections have been gathered from available market sources and materials to serve as a guide in illustrating potential market trends.

This section of the Report also provides a historical spark spread analysis based on past market conditions. The spark spread analysis is prepared to provide an indication of how a project similar to the proposed Spring Canyon Energy Project may have performed versus historical energy and natural gas prices.

ENERGY PRICES

Figures 8-1 and 8-2 provide an illustration of historical wholesale energy prices at four of the major trading hubs in the WECC for the period January 1998 through December 2001. Prices represent the average of the daily "on-peak" index prices for each month as published in Power Markets Week. The major trading hubs include:

- California-Oregon Border (COB): Northern California and Oregon
- Mid-Columbia: Pacific Northwest
- Four Corners: Desert Southwest
- Palo Verde: Southern California, Southern Nevada, and Arizona

Figure 8-1
Illustration of "On Peak" Energy Prices
Within the Western Electricity Coordinating Council
(January 1998 through May 2000)

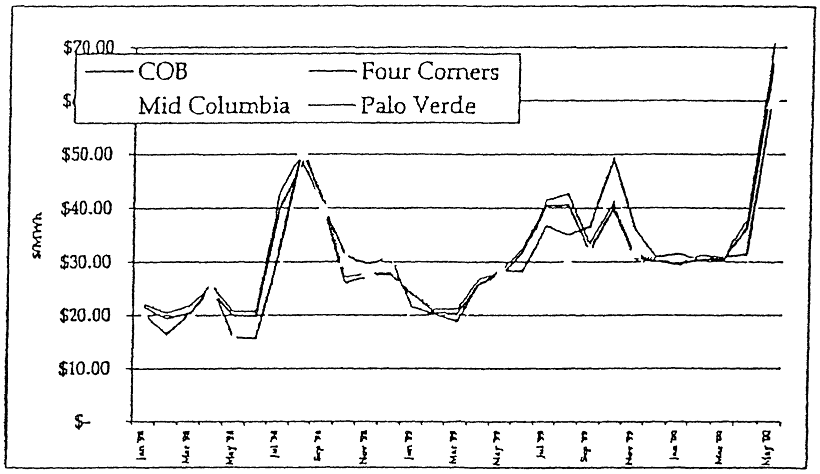
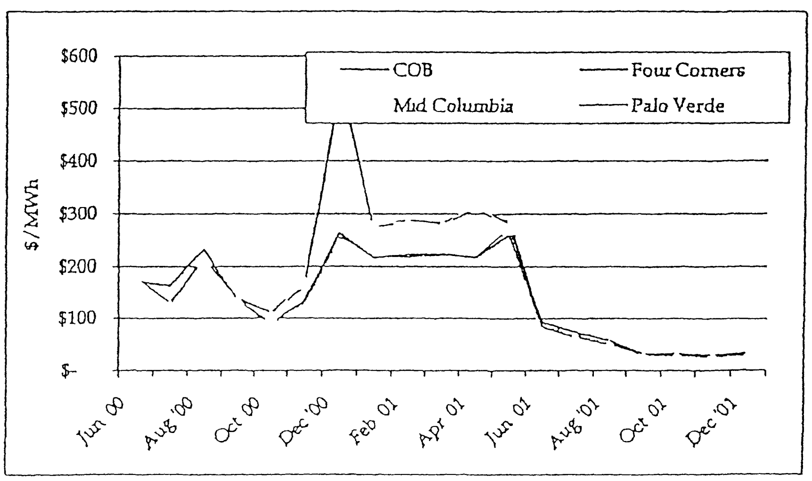


Figure 8-2
Illustration of "On Peak" Energy Prices
Within the Western Electricity Coordinating Council
(June through December 2000)



For the period shown in Figure 8-1, wholesale energy prices ranged from $15 to $70 per megawatt-hour depending on the specific time of year. During April and May 2000, energy prices began to spike, as early signs of an energy crisis in the west began to surface. Figure 8-2 provides an illustration of wholesale energy prices at the same trading hubs for the period June 2000 through December 2001 Average index prices for

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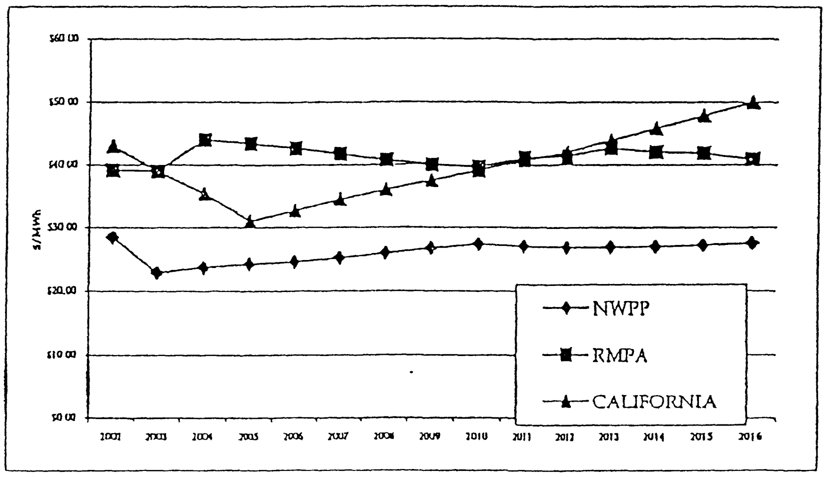
this period exceeded $500 per megawatt-hour at the California-Oregon Border as California entered an energy crisis in late 2000. Average prices remained above $200 per megawatt-hour for the first half of 200,1 as California and other western states attempted to manage supply shortages throughout the WECC.

To provide an indication of future energy prices, Navigant Consulting has gathered existing information from both the Energy Information Administration (EIA) and the California Energy Commission (CEC), which is summarized in Figure 8-3. EIA price projections are provided for two areas within the WECC: the Northwest Power Pool (NWPP) and the Rocky Mountain Power Pool (RMPA). Information from the CEC was used to serve as an estimate for energy projections in California.

Figure 8-3
Illustration of Projected Prices
Within the Western Electricity Coordinating Council
(2002 through 2016)



ELECTRICITY PRICE CAPS

As a result of the energy crisis that California and the entire western United States encountered in late 2000 and early 2001, FERC ruled in June 2001, to institute a Price Mitigation Plan (i.e. wholesale price cap) for electricity bought and sold across the WECC. The WECC-wide price cap, determined by the CAISO and reserves in California, can vary depending on market conditions. Currently, the maximum CAISO clearing price or price cap is approximately $92/MWh. To encourage energy sales into California, suppliers would be able to receive up to 100 percent of the price cap in California and only 85 percent of the price cap elsewhere in the WECC.

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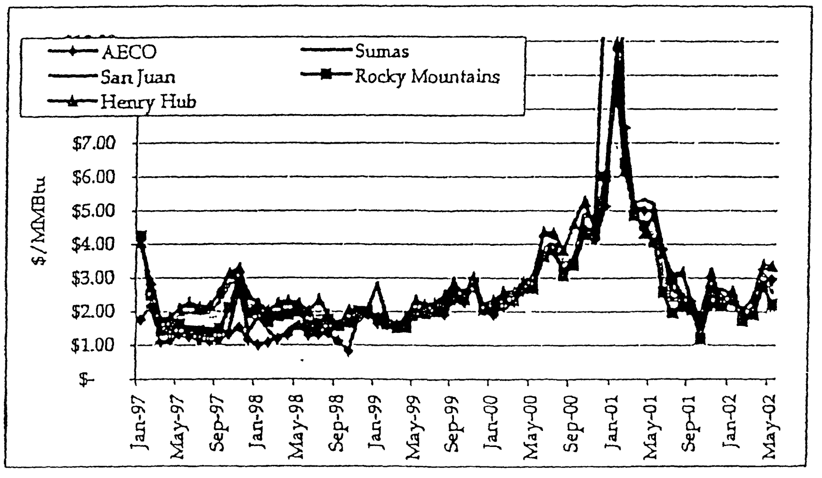
The June 2001 FERC Order calls for the price mitigation to expire at the end of September 2002. In a recent hearing of the United States Senate Committee on Energy and Natural Resources, FERC Commissioner Pat Wood III, reaffirmed the September 2001 expiration date included in the June FERC Order.

NATURAL GAS PRICES

Figure 8-4 shows historical natural gas prices for the major basins (AECO, San Juan, and Rocky Mountain) as well as for Henry Hub for the period January 1997 though April 2002.

Figure 8-4
Illustration of Historical Gas Prices
(1997 through 2002)



Natural gas prices generally ranged from $1.00 to $3.00/MMBtu during the period 1997 through 1999. Beginning in early 2000, and as the energy crisis in the west peaked, natural gas prices climbed from $2.00 to $10.00/MMBtu in late 2000 to early 2001. After natural gas prices peaked in early 2001, prices declined rapidly during 2001, returning to the $2.00 to $3.00/MMBtu range in September and October 2001.

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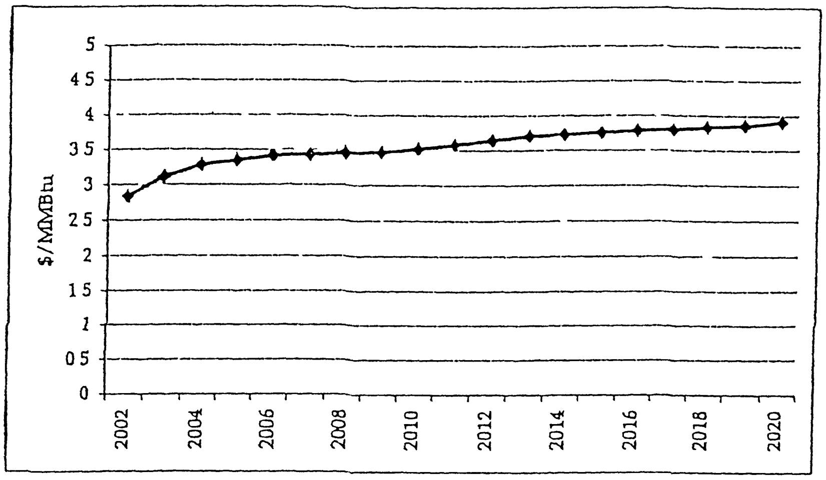
Figure 8-5
Illustration of Projected Natural Gas Prices
Within the Western Electricity Coordinating Council
(2001 through 2022)



In addition to Figure 8-5, Table 8-1 summarizes the historical average annual natural gas price differentials between the San Juan and Rocky Mountain basins. As the table indicates, from the period 1997 through 2001, the price of Rocky Mountain natural gas has averaged from $0.06 to $0.33 per MMBtu lower than San Juan natural gas Monthly price differentials from both basins are provided in Table 8-3.

Table 8-1
Historical Natural Gas Basin Differentials
Rocky Mountain Basin versus San Juan Basin
(1997 through 2001)

	Average Annual Basin Prices ($/MMBtu)				
Category	*1997*	*1998*	*1999*	*2000*	*2001*
San Juan Basin	$2 33	$1 87	$2 05	$3 51	$3 76
Rocky Mountain Basin	$2 00	$1 80	$2 03	$3 40	$3 60
Basin Differential	($0 33)	($0 06)	($0 02)	($0 11)	($0 16)

HISTORICAL SPARK SPREAD ANALYSIS

A key aspect in gaining financial support for moving forward with a proposed power project involves demonstrating the proposed project's viability in the marketplace One such measurement of viability includes conducting a "spark spread" analysis that indicates how a project would perform after taking into consideration future market prices for energy, and in this case, future fuel prices for natural gas

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Although Navigant Consulting did not conduct a comprehensive spark spread analysis for the Spring Canyon Project, or project future energy and natural gas prices to accomplish such, Navigant Consulting was asked to perform a summary spark spread analysis using historical energy and natural gas prices. The purpose of the summary analysis is to provide an indication of how a project with similar performance characteristics to the Spring Canyon Project may have performed versus the market.

Table 8-2 identifies the major components of the analysis and provides an estimation of a monthly spark spread. In order to provide a spark spread estimate that was indicative of "normal" market conditions, Navigant Consulting selected a 1999 test year. Although the energy markets in the west were indeed in a state of regulatory transition in 1999, wholesale prices for electricity and natural gas were not as volatile as demonstrated in 2000 and 2001, and there was no immediate energy crisis impacting the respective markets.

For this analysis, Navigant Consulting provided two bases for determining a spark spread: 1) Palo Verde, and 2) Four Corners, since the electricity prices from these trading hubs are indicative of the area that the Spring Canyon Project may serve. The major components of the analysis include:

- A delivered price for natural gas (Annual average $2.22/MMBtu)
- Market price for electricity (Annual average Palo Verde $30.38/MWh and Four Corners $31.26)
- Assumed heat rate (7,122 Btu/kWh).
- Variable Operation and Maintenance Component ($2.00/MWh)

Table 8-2
Illustration of Estimated Historical Spark Spread Analysis
For the Proposed Spring Canyon Power Project, LLC
Test Year – 1999

Component	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann. Avg
Rocky Mt. Basin Gas Price ($/MMBtu)	1.79	1.62	1.51	1.52	1.97	1.94	1.99	2.18	2.55	2.37	2.86	2.05	2.03
Natural Gas Transport. Rate ($/MMBtu)	0.19	0.19	0.19	0.19	0 19	0.19	0.19	0.19	0.19	0.19	0.19	0 19	0.19
Delivered Price of Natural Gas ($/MMBtu)	1.98	1.81	1.70	1.71	2.16	2.13	2.18	2.37	2.74	2.56	3.05	2.24	2.22
Elect Mkt Price – Four Corners ($/MWh)	24 07	20.65	20.40	25.81	27 61	31.90	40.55	40.71	31.91	39.95	30.85	30.22	30.38
Elect. Mkt Price – Palo Verde ($/MWh)	24.17	21.17	21.25	26.79	28.41	32.68	41.49	42.71	33.40	41.06	31.51	30 51	31.26
Assumed Project Heat Rate (Btu/kWh)	7,122	7,122	7,122	7,122	7,122	7,122	7,122	7,122	7,122	7,122	7,122	7,122	7,122
Variable Op. & Maint. Costs ($/MWh)	2.00	2.00	2.00	2.00	2.00	2.00	2 00	2.00	2.00	2.00	2.00	2 00	2.00
Production Costs of Electricity ($/MWh)	16.07	14.86	14.08	14.15	17.36	17.14	17 50	18.85	21.49	20.20	23.69	17.92	17.78
Spark Spread at Four Corners ($/MWh)	8.00	5.79	6.32	11.66	10.25	14.76	23.05	21.86	10.42	19.74	7.16	12 29	12.61
Spark Spread at Palo Verde ($/MWh)	8.10	6.31	7.17	12.64	11.05	15.54	23.99	23.86	11.92	20.86	7.82	12.58	13.49

Notes

(1) Historical market prices for electricity at Four Corners and Palo Verde based on the monthly average of daily index "On-peak" prices as published in Power Markets Week.

(2) On-Peak electricity prices represent 16 hour block (Hour ending 6 am through Hour ending 10 pm)

(3) Historical Rock Mountain Basin natural gas prices based on information published in Gas Daily – Monthly Contract Price

(4) Natural Gas Transportation rate based on firm transmission rate from Questar's current FERC gas transportation tariff. Rate includes reservation charge and usage charge.

(5) Figures shown above are intended to provide an indication of historical price differentials between the market and a facility with a similar heat rate to the proposed Spring Canyon Power Project.

Based on these general assumptions, the results of the historical spark spread analysis concludes that a project with similar performance characteristics of the Spring Canyon Project would have a annual average spark spread between approximately $12.50 and $13.50/MWh.

CONCLUSIONS

In summarizing much of the historical energy and natural gas price data within the WECC, as well as considering the operational characteristics of the proposed Spring Canyon Project, some general conclusions can be made with regard to the Project:

- The expiration of the FERC price caps at the end of September 2002 will not negatively impact the proposed Spring Canyon Energy Project; rather it provides a market environment for potentially capitalizing on the efficient characteristics of the Project.

- Historical average natural gas price differentials at the San Juan and Rocky Mountain Basin suggest a competitive advantage for the Project's close proximity and access to Rocky Mountain natural gas.

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- A spark spread analysis based on historical energy prices, natural gas prices, and the efficient operational characteristics of the Project reveal an average annual spark spread of $12.50 to $13.50 during non-emergency market conditions.

APPENDIX A

SPRING CANYON ENERGY LLC
PRELIMINARY MARKET ASSESSMENT LOADS AND RESOURCES BALANCE
UTAH MARKET AREA - PEAK DEMAND
(2002 THROUGH 2011)

CATEGORY	[1] 2002	[2] 2003	[3] 2004	[4] 2005	[5] 2006	[6] 2007	[7] 2008	[8] 2009	[9] 2010	[10] 2011	AVERAGE GROWTH
I LOADS											
(A) INVESTOR-OWNED UTILITIES (IOUs)											
PacifiCorp	3 820	3 909	4 018	4 113	4 201	4,306	4,344	4 490	4 556	4 760	2 %
SUBTOTAL IOUS	3 820	3 909	4 018	4 113	4 201	4,306	4,344	4 490	4,556	4 760	2 %
(B) MUNICIPALITIES/ELECTRIC CO-OPS (MUNICIPAL)											
UMPA	206	211	217	222	227	232	234	242	246	257	2 5%
UAMPS	603	617	634	649	663	680	686	709	719	7[illegible]	2.5%
COOPS	165	169	174	178	181	186	188	194	197	206	5%
SUBTOTAL MUNICIPAL	974	997	1 024	1 049	1 071	1 098	1 108	1 145	1 162	1 14	2.5%
(C) TOTAL LOAD	4 794	4 906	5 042	5 162	5,272	5 404	5 452	5 635	5 718	5 974	2 3
(D) RESERVE MARGIN (10%)	479	491	504	516	527	540	545	563	572	597	2.5%
TOTAL LOADS	5 273	5,396	5,547	5 678	5 799	5,944	5,997	6,198	6,289	6,571	2.5
II RESOURCES											
(A) EXISTING GENERATION CAPACITY											
Hydro	247	247	247	247	247	247	247	247	247	247	NA
Natural Gas/Oil	419	419	419	419	419	419	419	419	419	4 9	NA
Coal	4 486	4 486	4 486	4 486	4 436	4 486	4 486	4 486	4 486	4 486	NA
Renewables	12	12	12	12	12	12	12	12	12	12	NA
Other	55	55	55	55	55	55	55	55	55	55	NA
SUBTOTAL EXISTING GENERATION	5,219	5 219	5,219	5 219	5 219	5 219	5,219	5 219	5 219	5 2 9	NA
(B) PROPOSED NEW GENERATION CAPACITY											
Hydro	0	0	0	0	0	0	0	0	0	0	NA
Natural Gas/Oil	80	200	220	220	220	220	220	220	220	2 0	NA
Coal	0	0	0	0	0	0	0	0	0	0	NA
Renewables	0	0	0	0	0	0	0	0	0	0	NA
Other	0	0	0	0	0	0	0	0	0	0	NA
SUBTOTAL NEW GENERATION	80	200	220	220	220	220	220	220	2 0	220	NA
(C) OUTAGE ADJUSTMENT FACTOR (__%)	0	0	0	0	0	0	0	0	0	0	NA
(D) TRANSMISSION IMPORTS											
Simultaneous Import Capability	2,200	2,200	2,200	2,200	2,200	2,200	2 200	2 200	2 200	2,200	NA
TOTAL RESOURCES	7 499	7 619	7 639	7 639	7 639	7 639	7 639	7 639	7 639	7 639	NA
LOAD / RESOURCE BALANCE (SURPLUS/(DEFICIT))	2,226	2,223	2,092	1 961	1 840	1 695	1 642	1 441	1,350	1 068	NA
PERCENT OF TOTAL LOAD	42%	41%	38%	35%	32%	29%	27%	23%	21%	16%	NA
LOAD / RESOURCE BALANCE (SURPLUS/(DEFICIT)) -	982	979	848	717	596	451	398	197	106	(76)	NA
PERCENT OF TOTAL LOAD	19%	18%	15%	13%	10%	8%	7%	3%	2%	3%	NA

SPRING CANYON ENERGY LLC
PRELIMINARY MARKET ASSESSMENT LOADS AND RESOURCES BALANCE
ARIZONA MARKET AREA - PEAK DEMAND
(2002 THROUGH 2011)

CATEGORY	[1] 2002	[2] 2003	[3] 2004	[4] 2005	[5] 2006	[6] 2007	[7] 2008	[8] 2009	[9] 2010	[10] 2011	AVERAGE GROWTH
I. LOADS											
(A) INVESTOR-OWNED UTILITIES (IOUs)											
Arizona Public Service Company	5 495	5 687	5 886	6 092	6,306	6,526	6 755	6 991	7,236	7 439	3.5%
Citizens Comm.	434	449	465	481	498	515	533	552	571	591	3.5%
Morenci Water & Electric	191	197	204	211	219	226	234	242	251	260	3.5%
Tucson Electric Power	1 918	1,985	2,054	2,126	2,201	2,278	2,358	2,440	2,525	2,614	3.5%
SUBTOTAL IOUS	8 037	8 318	8 610	8 911	9,223	9,546	9 880	10 225	10 583	10 934	3.5%
(B) MUNICIPALITIES/ELECTRIC CO-OPS (MUNICIPAL)											
Continental Divide El Coop Inc	66	67	69	70	71	73	74	76	77	79	2.0%
Dixie Escalante R E A Inc	46	47	48	49	50	51	52	53	54	55	2.0%
Electrical District No 2 Pinal County	47	45	49	50	51	52	53	54	56	57	2.0%
Electrical District No 8 Maricopa	31	32	32	33	33	34	35	35	36	37	2.0%
Garkane Energy Cooperative, Inc.	24	24	25	25	26	26	27	27	28	28	2.0%
Graham County Electric Coop Inc	35	36	36	37	38	39	39	40	41	41	2.0%
City of Mesa	91	92	94	96	98	100	102	104	106	108	2.0%
Mohave Electric Coop Inc	151	154	158	161	164	167	171	174	177	181	2.0%
Navajo Tribal Utility Authority	127	129	132	134	137	140	143	146	148	151	2.0%
Navopache Electric Coop Inc	59	60	61	62	64	65	66	67	69	70	2.0%
Salt River Project Ag I & P Dist	5 152	5 255	5,360	5 467	5,577	5 688	5 802	5 918	6,036	6 157	2.0%
Sulphur Springs Valley E C Inc	111	113	116	118	120	123	125	128	130	133	2.0%
Trico Electric Coop Inc.	90	91	93	95	97	99	101	103	105	107	0%
U S Bureau of Indian Affairs	78	80	81	83	85	86	88	90	92	94	2.0%
Other (30 Small Utilities/Coops)	1 409	1,430	1 452	1 473	1 496	1,513	1,541	1,564	1,587	1 611	1.5%
SUBTOTAL MUNICIPAL	7,517	7 660	7 806	7 955	8 107	8,262	8 419	8 580	8 744	8 911	1.9%
(C) TOTAL LOADS	15 554	15,979	16 416	16 866	17,330	17 807	18,299	18 805	19,327	19 864	3%
(D) RESERVE MARGIN (10%)	1 555	1,598	1 642	1 687	1 733	1 781	1 830	1 881	1 933	1 986	2.8%
TOTAL LOADS	17 109	17 576	18 057	18 553	19,063	19,588	20 129	20,686	21 260	21 851	2.8%
II RESOURCES											
(A) EXISTING GENERATION CAPACITY											
Coal	5 311	5 311	5,311	5,311	5,311	5,311	5,311	5,311	5,311	5 311	NA
Petroleum	240	240	240	240	240	240	240	240	240	240	NA
Gas	4 398	4,398	4,398	4 398	4,398	4 398	4 398	4,398	4,398	4 398	NA
Nuclear	3 733	3 733	3 733	3 733	3 733	3 733	3 733	3 733	3 733	3 733	NA
Hydroelectric	2,887	2,887	2,887	2,887	2,887	2 887	2,887	2,887	2,887	2,887	NA
Renewable	1	1	1	1	1	1	1	1	1	1	NA
Other (IPP Non Classified)	168	168	168	168	168	168	168	168	168	168	NA
SUBTOTAL EXISTING GENERATION	16 738	16 738	16,738	16 738	16 738	16 738	16 738	16 738	16 738	6 738	NA
(B) PROPOSED NEW GENERATION CAPACITY											
Coal	0	95	95	95	190	190	190	190	190	190	NA
Petroleum	0	0	0	0	0	0	0	0	0	0	NA
Gas	1,280	4 265	7 684	8 160	8 675	8 675	8 940	8 940	8 940	8 940	NA
Nuclear	0	0	0	0	0	0	0	0	0	0	NA
Hydroelectric	0	0	0	0	0	0	0	0	0	0	NA
Renewable	0	0	0	0	0	0	0	0	0	0	NA
Other (IPP Non Classified)	0	0	0	0	0	0	0	0	0	0	NA
SUBTOTAL NEW GENERATION	1 280	4,360	7 779	8 255	8,865	8 865	9 130	9 130	9 130	9 130	NA
(C) OUTAGE ADJUSTMENT FACTOR (__%)	0	0	0	0	0	0	0	0	0	0	NA
(D) TRANSMISSION IMPORT CAPABILITY											
Simultaneous Transfer Capability	5 000	5 000	5 000	5 000	5 000	5 000	5 000	5 000	5 000	5 000	NA
TOTAL RESOURCES	23 018	26 098	29 517	29 993	30 603	30 603	30 868	30,868	30 868	30,868	NA
LOAD / RESOURCE BALANCE (SURPLUS/(DEFICIT))	5,909	8,522	11,459	11 440	11,540	11 015	10 739	10 182	9 608	9 017	NA
PERCENT OF TOTAL LOAD	35%	48%	63%	62%	61%	56%	53%	49%	45%	41%	NA

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SPRING CANYON ENERGY, LLC
PRELIMINARY MARKET ASSESSMENT - LOADS AND RESOURCES BALANCE
NORTHERN NEVADA MARKET AREA - PEAK DEMAND
(2002 THROUGH 2011)

CATEGORY	[1] 2002	[2] 2003	[3] 2004	[4] 2005	[5] 2006	[6] 2007	[7] 2008	[8] 2009	[9] 2010	[10] 2011	AVERAGE GROWTH
I LOADS:											
(A) INVESTOR-OWNED UTILITIES (IOUs):											
Sierra Pacific Power	1,657	1,700	1,744	1,790	1,808	1,826	1,844	1,862	1,881	1,900	1.5%
SUBTOTAL - IOUS	1,657	1,700	1,744	1,790	1,808	1,826	1,844	1,862	1,881	1,900	1.5%
(B) MUNICIPALITIES/ELECTRIC CO-OPS (MUNICIPAL):											
Wells Rural Electric Cooperative	102	104	106	108	109	110	112	113	114	115	1.3%
Mount Wheeler Power Inc.	44	45	46	47	47	48	48	49	49	50	1.3%
Fallon Municipal Electric System	15	15	16	16	16	16	16	17	17	17	1.3%
SUBTOTAL - MUNICIPAL	161	164	168	171	173	174	176	178	180	181	1.3%
(C) TOTAL LOAD	1,818	1,864	1,912	1,960	1,980	2,000	2,020	2,040	2,060	2,081	1.5%
(D) RESERVE MARGIN (7%)	127	131	134	137	139	140	141	143	144	146	1.5%
TOTAL LOADS	1,945	1,995	2,046	2,098	2,119	2,140	2,161	2,183	2,205	2,227	1.5%
II RESOURCES:											
(A) EXISTING GENERATION CAPACITY:											
Coal	621	621	621	621	621	621	621	621	621	621	NA
Natural Gas	1,002	1,002	1,002	1,002	1,002	1,002	1,002	1,002	1,002	1,002	NA
Hydro	11	11	11	11	11	11	11	11	11	11	NA
Diesel/Fuel Oil	72	72	72	72	72	72	72	72	72	72	NA
Geothermal	192	192	192	192	192	192	192	192	192	192	NA
SUBTOTAL - EXISTING GENERATION	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	NA
(B) PROPOSED NEW GENERATION CAPACITY:											
Coal	0	0	0	0	0	0	0	0	0	0	NA
Natural Gas	0	0	135	135	135	135	135	135	135	255	NA
Hydro	0	0	0	0	0	0	0	0	0	0	NA
Diesel/Fuel Oil	0	0	0	0	0	0	0	0	0	0	
Geothermal	12	12	12	12	12	12	12	12	12	12	NA
SUBTOTAL - NEW GENERATION	12	12	147	147	147	147	147	147	147	267	NA
(C) OUTAGE ADJUSTMENT (__%)	0	0	0	0	0	0	0	0	0	0	NA
(D) TRANSMISSION IMPORT CAPABILITY:											
Simultaneous Transfer Capability	650	650	650	850	850	850	850	850	850	850	NA
TOTAL RESOURCES	2,560	2,560	2,695	2,895	2,895	2,895	2,895	2,895	2,895	3,015	NA
LOAD / RESOURCE BALANCE (SURPLUS/((DEFICIT))	614	565	649	797	776	755	733	712	690	788	NA
PERCENT OF TOTAL LOAD	32%	28%	32%	38%	37%	35%	34%	33%	31%	35%	NA

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SPRING CANYON ENERGY LLC
PRELIMINARY MARKET ASSESSMENT - LOADS AND RESOURCES BALANCE
SOUTHERN NEVADA MARKET AREA - PEAK DEMAND
(2002 THROUGH 2011)

CATEGORY	[1] 2002	[2] 2003	[3] 2004	[4] 2005	[5] 2006	[6] 2007	[7] 2008	[8] 2009	[9] 2010	[10] 2011	AVERAGE GROWTH
I LOADS											
(A) INVESTOR-OWNED UTILITIES (IOUs):											
Nevada Power Company	4,311	4,557	4,816	5,091	5,381	5,688	6,012	6,355	6,717	7,100	5.7%
SUBTOTAL - IOUS	4,311	4,557	4,816	5,091	5,381	5,688	6,012	6,355	6,717	7,100	5.7%
(B) MUNICIPALITIES/ELECTRIC CO-OPS (MUNICIPAL):											
Alamo Power District No 3	3	3	3	3	3	3	3	3	3	3	1.0%
City of Boulder	48	49	50	51	52	53	54	55	56	57	2.0%
City of Caliente	3	3	3	3	3	3	3	3	3	3	1.0%
Colorado River Comm of Nevada	324	330	337	344	351	358	365	372	380	387	2.0%
Lincoln County Power District No. 1	15	15	15	15	16	16	16	16	16	16	1.0%
Overton Power District No. 5	70	71	73	74	76	77	79	80	82	84	2.0%
Panaca Power & Light Company	2	2	2	2	2	2	2	2	2	2	1.0%
City of Pioche	2	2	2	2	2	2	2	2	2	2	1.0%
Valley Electric Association	94	96	98	100	102	104	106	108	110	112	2.0%
SUBTOTAL - MUNICIPAL	561	572	583	595	606	618	630	642	655	668	2.0%
(C) TOTAL LOADS	4,872	5,129	5,400	5,686	5,987	6,306	6,642	6,997	7,372	7,768	5.3%
(D) RESERVE MARGIN (7%)	341	359	378	398	419	441	465	490	516	544	5.3%
TOTAL LOADS	5,213	5,488	5,778	6,084	6,407	6,747	7,107	7,487	7,888	8,312	5.3%
II. RESOURCES											
(A) EXISTING GENERATION CAPACITY:											
Coal	2,185	2,185	2,185	2,185	2,185	2,185	2,185	2,185	2,185	2,185	NA
Natural Gas	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321	NA
Hydro	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039	NA
Diesel/Fuel Oil	202	202	202	202	202	202	202	202	202	202	NA
Geothermal	0	0	0	0	0	0	0	0	0	0	NA
SUBTOTAL - EXISTING GENERATION	5,748	5,748	5,748	5,748	5,748	5,748	5,748	5,748	5,748	5,748	NA
(B) PROPOSED NEW GENERATION CAPACITY:											
Coal	0	0	0	0	0	0	0	0	0	0	NA
Natural Gas	0	1,980	2,846	3,371	3,371	3,371	3,371	3,371	3,371	3,694	NA
Hydro	0	0	0	0	100	100	100	100	100	100	NA
Diesel/Fuel Oil	0	0	0	0	0	0	0	0	0	0	NA
Geothermal	0	0	0	0	0	0	0	0	0	0	NA
SUBTOTAL - NEW GENERATION	0	1,980	2,846	3,371	3,471	3,471	3,471	3,471	3,471	3,794	NA
(C) OUTAGE ADJUSTMENT (__%)	0	0	0	0	0	0	0	0	0	0	NA
(D) TRANSMISSION IMPORT CAPABILITY											
Simultaneous Transfer Capability	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	NA
TOTAL RESOURCES	9,748	11,728	12,594	13,119	13,219	13,219	13,219	13,219	13,219	13,542	NA
LOAD / RESOURCE BALANCE (SURPLUS/((DEFICIT))	4,535	6,240	6,817	7,036	6,813	6,472	6,112	5,732	5,331	5,230	NA
PERCENT OF TOTAL LOAD	87%	114%	118%	116%	106%	96%	86%	77%	68%	63%	NA

SPRING CANYON ENERGY LLC
PRELIMINARY MARKET ASSESSMENT - LOADS AND RESOURCES BALANCE
SOUTHERN CALIFORNIA MARKET AREA - PEAK DEMAND
(2002 THROUGH 2011)

CATEGORY	[1] 2002	[2] 2003	[3] 2004	[4] 2005	[5] 2006	[6] 2007	[7] 2008	[8] 2009	[9] 2010	[10] 2011	AVERAGE GROWTH
I. LOADS											
(A) INVESTOR-OWNED UTILITIES (IOUs)											
Southern California Edison	19 469	19 820	20 176	20,540	20 909	21 286	21 669	22,059	22 456	22 860	1.8%
San Diego Gas and Electric	3 660	3 755	3 853	3 953	4 055	4 161	4,269	4 380	4 494	4 61	2.6%
SUBTOTAL IOU'S	23 129	23 575	24 029	24 492	24 965	25 447	25 938	26 439	26 950	27 47	1.9%
(B) MUNICIPALITIES/ELECTRIC CO-OPS (MUNICIPAL)											
Anaheim Public Utilities Department	608	619	631	643	655	663	680	693	706	720	1.9%
Burbank Public Service Department	281	284	288	291	295	298	302	306	309	313	1
California Department of Water Resources	1 059	1 059	1 059	1 059	1 059	1 059	1 059	1 059	1 059	1 059	0.0%
Glendale Public Service Department	312	315	319	323	327	331	335	339	343	347	1.2%
Imperial Irrigation District	735	753	771	790	809	828	848	868	889	9 0	2.4 %
Los Angeles Department of Water and Power	5 486	5 541	5 597	5 653	5 709	5 766	5 824	5 882	5 941	6 000	1.0%
Metropolitan Water District of So. California	297	297	297	297	297	297	297	297	297	297	0.0%
Pasadena Water and Power Department	286	289	292	295	299	302	305	309	312	3 5	[illegible]
Riverside Utilities	494	505	516	528	539	551	563	576	588	601	
Cities of Azusa, Banning, and Colton	167	171	175	179	183	187	191	195	199	204	2 ~
Vernon Municipal Light Department	202	206	209	213	217	222	226	230	234	239	1.9%
Anza Electric Cooperative	9	9	9	10	10	10	10	10	10	10	[illegible]
City of Needles	16	16	17	17	17	17	18	18	15	15	4%
SUBTOTAL MUNICIPAL	9 953	10,066	10,181	10,297	10,415	10 535	10 657	10 781	10 907	1 034	[illegible]
(C) TOTAL LOADS	33 082	33 640	34,210	34 789	35 380	35 982	36 595	37,220	37 857	38 505	1.7%
(D) RESERVE MARGIN (7%)	2,316	2,355	2,395	2,435	2,477	2,519	2 562	2,605	2 650	2 695	1.7%
TOTAL LOADS	35,397	35,995	36 604	37 225	37 857	38 501	39 157	39 826	40 507	41 201	1.7%
II. RESOURCES											
(A) EXISTING GENERATION CAPACITY											
Hydro	4,273	4 273	4,273	4 273	4 273	4 273	4,273	4 273	4 273	4,273	NA
Natural Gas/Oil	19 494	19 494	19 494	19 494	19 494	19 494	19 494	19 494	19 494	19 494	NA
Geothermal	36	36	36	36	36	36	36	36	36	36	NA
Nuclear	2 150	2,150	2,150	2,150	2,150	2 150	2 150	2 150	2 150	2 150	NA
Other	2,379	2,379	2,379	2,379	2,379	2,379	2 379	2,379	2,379	2,379	NA
SUBTOTAL EXISTING GENERATION	28,332	28 331	28,332	28,332	28,332	28,332	28,332	28,332	28,332	21,33	NA
(B) PROPOSED NEW GENERATION CAPACITY											
Hydro	0	0	0	0	0	0	0	0	0	0	NA
Natural Gas/Oil	500	5 726	6 845	7 650	7 650	7 650	7 650	7 650	7 650	7 650	NA
Geothermal	0	0	0	125	125	125	125	125	25	1 5	NA
Nuclear	0	0	0	0	0	0	0	0	0	0	NA
Other	0	0	0	0	0	0	0	0	0	0	NA
SUBTOTAL NEW GENERATION	500	5 726	6,845	7 775	7 775	7 775	7 775	7 775	7 775	7 775	NA
(C) OUTAGE ADJUSTMENT (17.5%)	(5 046)	(5 960)	(6 156)	(6,319)	(6,319)	(6 319)	(6,319)	(6,319)	(6 3 9)	(6 319)	NA
(D) TRANSMISSION IMPORT CAPABILITY											
Simultaneous Transfer Capability	13 000	13 000	13 000	13 000	13 000	13 000	13 000	3 000	13 000	3 000	NA
TOTAL RESOURCES	36 786	41 097	42,021	42,788	42,788	42,788	42,788	42,788	42,788	42,788	NA
LOAD / RESOURCE BALANCE (SURPLUS/(DEFICIT))	1,389	5,102	5,416	5,563	4,931	4 287	3 631	2,962	2 281	1,587	NA
PERCENT OF TOTAL LOAD	4%	14%	15%	15%	13%	11%	9%	7%	6%	4%	NA

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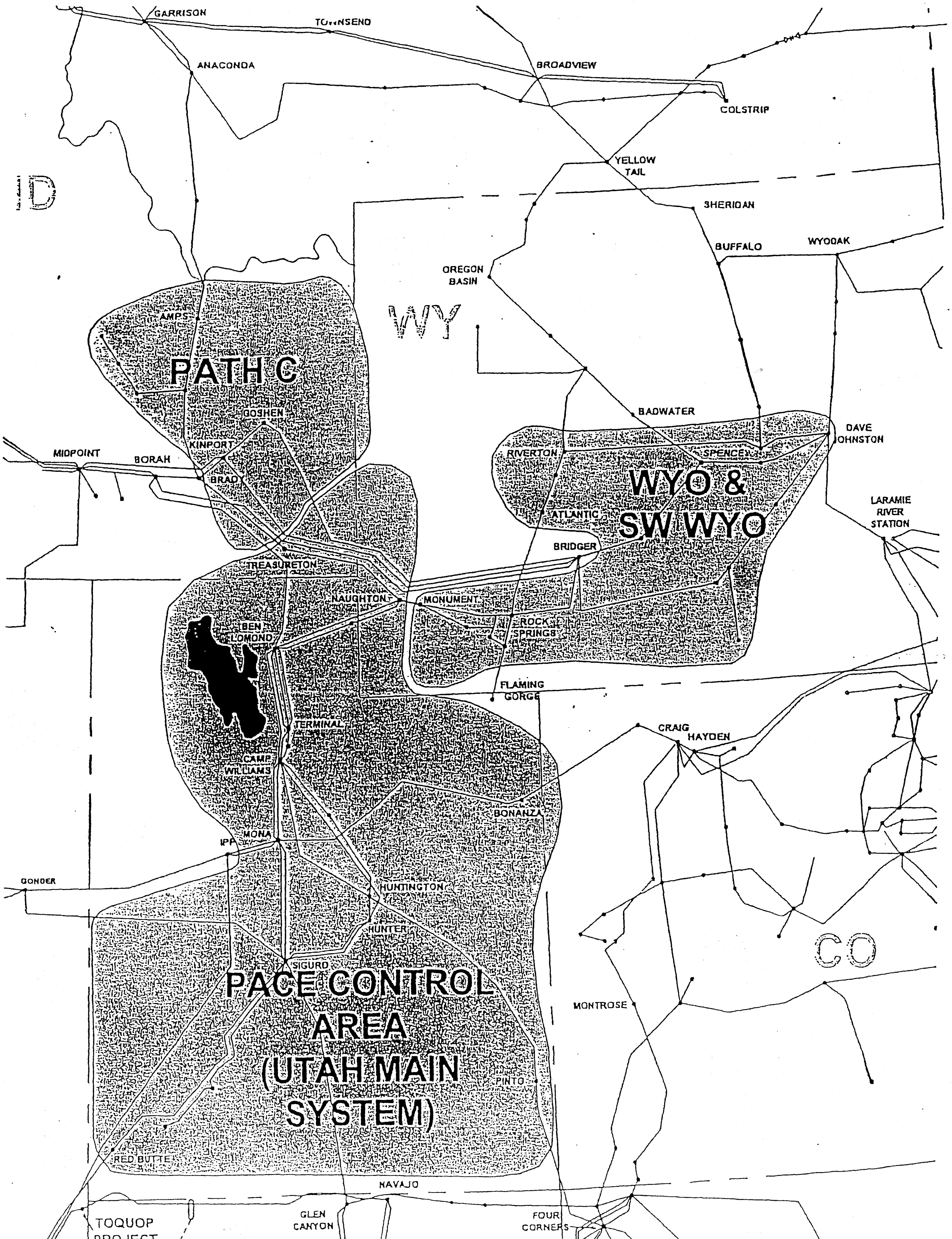
APPENDIX B


GARRISON
TOWNSEND
ANACONDA
BROADVIEW
COLSTRIP
YELLOW TAIL
ID
SHERIDAN
BUFFALO
WYODAK
OREGON BASIN
WY
AMPS
PATH C
GOSHEN
KINPORT
MIDPOINT
BORAH
BRADY
BADWATER
DAVE JOHNSTON
RIVERTON
SPENCE
WYO & SW WYO
ATLANTIC
BRIDGER
LARAMIE RIVER STATION
TREASURETON
NAUGHTON
MONUMENT
ROCK SPRINGS
BEN LOMOND
FLAMING GORGE
TERMINAL
CRAIG
HAYDEN
CAMP WILLIAMS
BONANZA
IPP
MONA
GONDER
HUNTINGTON
HUNTER
CO
SIGURD
PACE CONTROL AREA (UTAH MAIN SYSTEM)
MONTROSE
PINTO
RED BUTTE
NAVAJO
TOQUOP PROJECT
GLEN CANYON
FOUR CORNERS
OJO
TAOS

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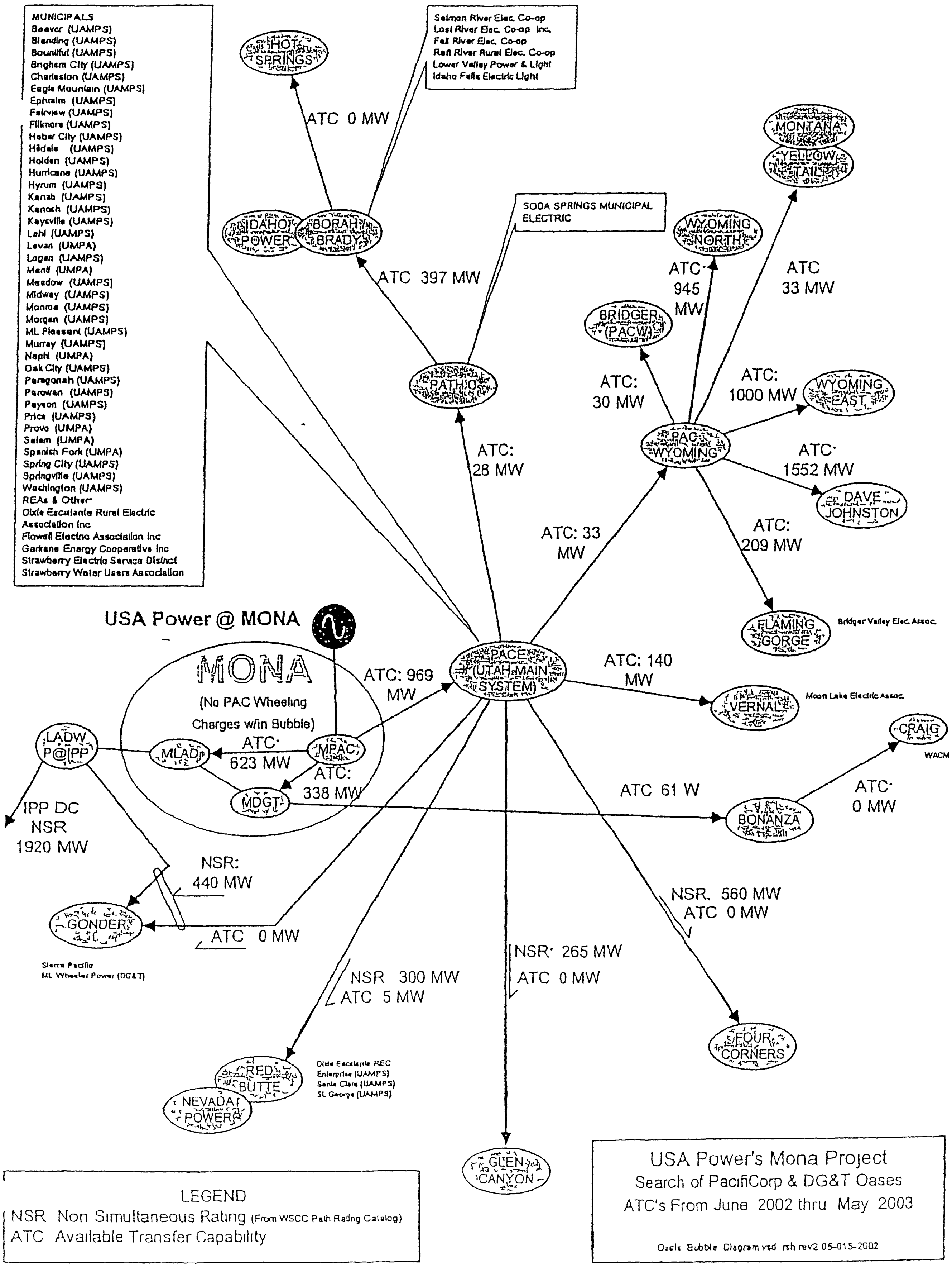
MUNICIPALS
Beaver (UAMPS)
Blanding (UAMPS)
Bountiful (UAMPS)
Brigham City (UAMPS)
Charleston (UAMPS)
Eagle Mountain (UAMPS)
Ephraim (UAMPS)
Fairview (UAMPS)
Fillmore (UAMPS)
Heber City (UAMPS)
Hildale (UAMPS)
Holden (UAMPS)
Hurricane (UAMPS)
Hyrum (UAMPS)
Kanab (UAMPS)
Kanosh (UAMPS)
Kaysville (UAMPS)
Lehi (UAMPS)
Levan (UMPA)
Logan (UAMPS)
Manti (UMPA)
Meadow (UAMPS)
Midway (UAMPS)
Monroe (UAMPS)
Morgan (UAMPS)
Mt. Pleasant (UAMPS)
Murray (UAMPS)
Nephi (UMPA)
Oak City (UAMPS)
Paragonah (UAMPS)
Parowan (UAMPS)
Payson (UAMPS)
Price (UAMPS)
Provo (UMPA)
Salem (UMPA)
Spanish Fork (UMPA)
Spring City (UAMPS)
Springville (UAMPS)
Washington (UAMPS)
REAs & Other
Dixie Escalante Rural Electric Association Inc
Flowell Electric Association Inc
Garkane Energy Cooperative Inc
Strawberry Electric Service District
Strawberry Water Users Association
Salmon River Elec. Co-op
Lost River Elec. Co-op Inc.
Fall River Elec. Co-op
Raft River Rural Elec. Co-op
Lower Valley Power & Light
Idaho Falls Electric Light
HOT SPRINGS
ATC 0 MW
IDAHO POWER
BORAH BRADY
ATC 397 MW
SODA SPRINGS MUNICIPAL ELECTRIC
PATH C
ATC: 28 MW
MONTANA
YELLOW TAIL
WYOMING NORTH
ATC 945 MW
ATC 33 MW
BRIDGER (PACW)
ATC: 30 MW
ATC: 1000 MW
WYOMING EAST
PAC WYOMING
ATC: 1552 MW
DAVE JOHNSTON
ATC: 209 MW
ATC: 33 MW
FLAMING GORGE
Bridger Valley Elec. Assoc.
USA Power @ MONA
MONA
(No PAC Wheeling Charges w/in Bubble)
ATC: 969 MW
PACE (UTAH MAIN SYSTEM)
ATC: 140 MW
VERNAL
Moon Lake Electric Assoc.
CRAIG
WACM
LADW P@IPP
MLAD
ATC: 623 MW
MPAC
ATC: 338 MW
MDGT
ATC 61 W
BONANZA
ATC: 0 MW
IPP DC NSR 1920 MW
NSR: 440 MW
GONDER
ATC 0 MW
Sierra Pacific
Mt. Wheeler Power (DG&T)
NSR. 560 MW
ATC 0 MW
NSR: 265 MW
ATC 0 MW
NSR 300 MW
ATC 5 MW
FOUR CORNERS
RED BUTTE
Dixie Escalante REC
Enterprise (UAMPS)
Santa Clara (UAMPS)
St. George (UAMPS)
NEVADA POWER
GLEN CANYON
LEGEND
NSR Non Simultaneous Rating (From WSCC Path Rating Catalog)
ATC Available Transfer Capability
USA Power's Mona Project
Search of PacifiCorp & DG&T Oases
ATC's From June 2002 thru May 2003
Oasis Bubble Diagram vsd rsh rev2 05-015-2002

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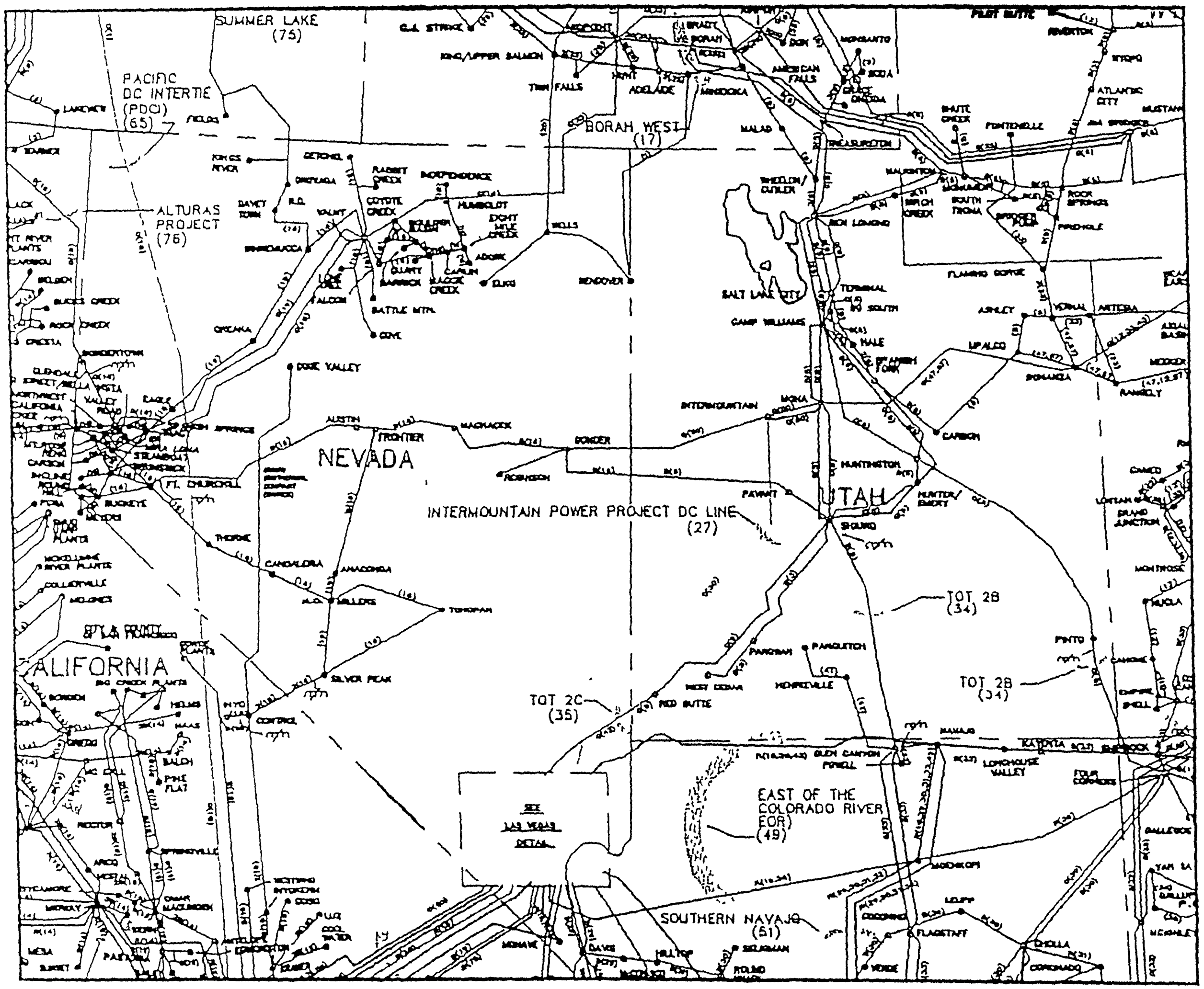
SUMMER LAKE (75)
PACIFIC DC INTERTIE (PDCI) (65)
ALTURAS PROJECT (76)
BORAH WEST (17)
NEVADA
UTAH
CALIFORNIA
INTERMOUNTAIN POWER PROJECT DC LINE (27)
TOT 2B (34)
TOT 2B (34)
TOT 2C (35)
SEE LAS VEGAS DETAIL
EAST OF THE COLORADO RIVER (EOR) (49)
SOUTHERN NAVAJO (51)
SALT LAKE CITY
TWIN FALLS
AMERICAN FALLS
BATTLE MTN.
AUSTIN
FT. CHURCHILL
SILVER PEAK
TONOPAH
MONA
INTERMOUNTAIN
HUNTINGTON
SIGURD
PAVANT
RED BUTTE
GLEN CANYON
NAVAJO
MOENKOPI
FLAGSTAFF
CHOLLA
CORONADO
FOUR CORNERS
SHIPROCK
MOHAVE
DAVIS
ELKO
WELLS
FALCON
GONDER
ROBINSON
MIDPOINT
BRIDGER
TERMINAL
CAMP WILLIAMS
SPANISH FORK
EMERY
CAMP WILLIAMS
CARBON
BONANZA
VERNAL
RANGELY
MONTROSE
GRAND JUNCTION
PINTO
PARAGAH
PANGUITCH
HELMS
BALCH
PINE FLAT
CONTROL
INYO
HILLTOP
SELIGMAN
ROUND VALLEY
KAYENTA
LONGHOUSE VALLEY

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Tab 7

APPENDIX C

PacifiCorp System-wide
Long-term Wholesale Purchases
Summer Capacity (MW)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020
Purchases												
Black Hills Capacity	68	68	68	68	68	68	68	68	68	68		-
Colockum (P)	103	103	-	-			-	-	-	-		-
CSPE	18	16	-	-	-	-	-	-	-		-	-
Deseret Annual	104	-	-	-	-	-	-	-	-			-
Gem State	22	22	22	22	22	22	22	22	22	22	22	22
Grant County	14	14	14	14	14	14	14	14	14	14	14	14
Idaho Load Control	150	150	150	150	150	150	150	150	150	150	150	150
Interruptible (P)	161	161	161	161	161	161	161	161	161	161	161	161
PGE Cove	2	2	2	2	2	2	2	2	2	2	2	2
QF Goshen	9	9	9	9	9	9	9	9	9	9	9	9
QF Or/Wa	67	67	67	67	67	67	67	67	67	67	67	67
QF Utah	60	60	60	60	60	60	60	60	60	60	60	60
QF Wyoming	3	3	3	3	3	3	3	3	3	3	3	3
Redding (P)	22	22	22	22	22	22	22	22	22	22	22	-
Trans Alta	300	400	400	400	400	400	-	-	-	-	-	-
Tri-State Basic	50	50	50	50	50	50	50	50	50	50	50	50
WPP Seasonal Ex (P)	50	50	50	50	50	50	50	50	-	-	-	-
WPP Summer Purchase	150	150	150	-	-	-	-	-	-	-	-	-
Purchased Power	1,351	1,345	1,226	1,076	1,076	1,076	676	676	626	626	558	537

PacifiCorp System-wide
Long-term Wholesale Sales
Summer Capacity (MW)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020
Sales												
APPA	35	15	25	-	-	-	-	-	-	-	-	-
APS Sea Ex (S)	480	480	480	480	480	480	480	480	480	480	480	480
Black Hills 1996	30	30	-	-	-	-	-	-	-	-	-	-
Black Hills Load	65	60	55	50	50	50	50	50	50	50	50	50
BPA Wind Sale	6	6	6	6	6	6	6	6	6	6	6	6
Canadian Entitlement	5	4	-	-	-	-	-	-	-	-	-	-
CDWR	100	100	100	100	-	-	-	-	-	-	-	-
Citizens Power	80	80	-	-	-	-	-	-	-	-	-	-
Clark County PUD	100	-	-	-	-	-	-	-	-	-	-	-
Clark-WT	10	10	-	-	-	-	-	-	-	-	-	-
Cowlitz-BHP	10	-	-	-	-	-	-	-	-	-	-	-
Hurricane Net Sale	3	3	3	3	3	3	3	-	-	-	-	-
Large Industrials	367	367	367	367	367	367	367	367	367	367	367	367
Montana Sell Back	70	70	70	70	70	70	-	-	-	-	-	-
Okanogan	5	-	-	-	-	-	-	-	-	-	-	-
PSCoI	176	176	176	176	176	176	176	176	176	176	176	176
Puget 2	200	200	200	-	-	-	-	-	-	-	-	-
SCE OWC	100	100	100	100	100	100	-	-	-	-	-	-
SCE Utah	100	100	100	100	100	100	-	-	-	-	-	-
Sierra 2	75	75	75	75	75	75	75	75	75	-	-	-
SMUD	100	100	100	100	100	100	100	100	100	100	-	-
Springfield	45	45	45	45	45	45	45	45	45	45	45	-
Tri-State Ex (S)	50	50	50	50	50	50	-	-	-	-	-	-
UMPA 1	8	8	8	8	-	-	-	-	-	-	-	-
UMPA 2	21	25	25	25	25	25	25	25	25	25	25	25
WAPA 1	60	60	60	60	-	-	-	-	-	-	-	-
WAPA 2	75	75	75	75	-	-	-	-	-	-	-	-
Total Sales	2,377	2,239	2,120	1,890	1,647	1,647	1,327	1,324	1,324	1,249	1,149	1,104

ABB CONSULTING

FATAL FLAW ANALYSIS OF USA POWER'S 550 MW GENERATING PLANT AT MONA 345KV SUBSTATION

REPORT NO.: CONSULTING – 2002-10368-2.R01

April 1, 2002

SUBMITTED TO:

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EXECUTIVE SUMMARY

USA Power Company is developing a project in Utah, about 80 miles south of Salt Lake City. This project involves 2 units with a combined output of 550 MW and planned in-service date by the end of year 2003. The plant will be located about 1 mile from PacificCorp's Mona 345kV substation. In this context, ABB Consulting has been contracted by USA Power to conduct a fatal flaw analysis.

2003 Summer WSCC base case power flow data file in PSS/E format was used for the study. In the base case, generation power flow pattern is from East and South to West and North. This case was modified to have this power plant connected to Mona 345kV substation.

Power transfer scenarios were studied to access the capability of the transmission network. The five scenarios are:

- North-West: Area 60
- East : Area 70
- South: Area 19
- South-West : Area 18
- West: Area 64

All branches within 4 tiers from Mona were defined as monitoring elements. In addition, 10 WSCC transfer 0 paths also were identified as monitoring elements (Table A, Figure A).

The thermal transfer limit analysis, based on N-1 criteria, for exporting the USA Power generation to the all five directions around Mona substation was performed, using PTI's "Must" program. All transfer limits then were checked and verified by AC contingency analysis, using PSS/E program.

It was found that the Path of Intermountain - Gonder - Pavant 230kV circuit (No 4 in Table A) is the most limiting element and the contingency of the 245kV line outage (64059 HUMBOLDT 345 64061 IDAHO-NV 345 1) is the most limiting contingency, when transport power out from Mona area. There is no other significant transfer limit identified as long as the export is less then 550 MW, except for moving power to the West. The Western transfer is limited around 227 MW. Details of transfer limits are given in the following page.

In addition to that, input assumptions and map are attached to the **Appendix A**; detailed output results, corresponding to the tables in Summary are listed in the Appendix B; and the results of AC contingency analysis for verification are listed in Appendix C.

1. Power Transfer to the West – Area 64 – Sierra Pacific Power
Phase shifter at Sigurd could help to increase power transfer capability, but not significantly.

Table 1. Transfer Limits for Power Transfer to the West

Incremental Transfer Limit (MW)	Overloaded branch or Path	Contingency	Transfer Limit with AC Analysis (MW)	Transfer Limit with Phase Shifter On (MW)
16	Path: Intermnt_Gonder_Pavant	(1)	0	32
227	Path: Intermountain_Gonder	(1)	255	255
341	Path: Intermnt_Gonder_Pavant	None	395	444
350	Path: Intermountain_Gonder	(2)	423	454
382	64056 GONDER 230 64124 UTAH-NEV 230 1	(1)	273	273

(1) - 64059 HUMBOLDT 345 64061 IDAHO-NV 345 1
(2) - 66210 PAVANT 230 66345 SIGURD 230 1

2. Power Transfer to the East – Area 70 –Public Service of Colorado
The system is able to move approximately 500 MW eastward. It is limited by the contingency of a transformer at Bonanza outage, which causes 138kV line from Bonanza to Rangely overloaded.

Table 2. Transfer Limits for Power Transfer to the East

Incremental Transfer Limit (MW)	Overloaded branch or Path	Contingency	Transfer Limit with AC Analysis (MW)
500	65192 BONANZA 138 66278 RANGELY 138 1	(1)	603

(1) - 65192 BONANZA 138 65193 BONANZA 345 1

3. Power transfer to the Northwest – Area 60 – Idaho Power
There is no significant transfer limit found under 550 MW of power transfer, though the Path of Intermountain - Gonder – Pavant is overloaded by a contingency of the 345kV line (64059 HUMBOLDT 345 64061 IDAHO-NV 345 1) in base case condition. If counted, the corresponding Incremental Transfer Limit could be 174 MW.

4. Power transfer to the South – Area 19 – Western Area Power Administration
There is no significant transfer limit found under 550 MW of power transfer, though the Path of Intermountain - Gonder – Pavant is overloaded by a contingency of the 345kV line (64059 HUMBOLDT 345 64061 IDAHO-NV 345 1) in base case condition. If counted, the corresponding Incremental Transfer Limit could be 262 MW.

5. Power transfer to the Southwest – Area 18 - Nevada Power load
There is no significant transfer limit found under 550 MW of power transfer, though the Path of Intermountain - Gonder – Pavant is overloaded by a contingency of the 345kV line (64059 HUMBOLDT 345 64061 IDAHO-NV 345 1) in base case condition. If counted, the corresponding Incremental Transfer Limit could be 248 MW.

Appendix A

Input Assumptions

- Load flow case: WSCC 2003 Summer peak load flow case in PSS/E format
- Tool and methodology: PTI's "Must" and PSS/E programs were used. First the thermal transfer limits were identified by using DC analysis. All transfer limits then were verified with AC contingency analysis.
- Monitoring elements: All branches within 4 ties from Mona Substation. Beside that 10 paths were also included (table A). Illustration in the Figure A.
- Reference:
  "WSCC 1998 Path Rating Catalog" by WSCC Technical Studies Subcommittee.

Table A. Paths identified as monitoring elements.

No	Path Name	Lines Including in the Path	Bus Numbers in the Power Flow	Transfer Rating (MW)
1	Intermountain - Mona 345kV	Intermountain – Mona 345kV	FROM BUS 26043 TO BUS 65995 CKT 1 FROM BUS 26043 TO BUS 65995 CKT 2	1200
2	Intermountain - Gonder 230kV	Intermountain – Gonder 230kV	FROM BUS 26041 TO BUS 64056 CKT 1	200 (EtW)
3	TOT_1A	Bears Ears – Bonanza 345kV Hayden – Artesia 138kV Meeker – Rangely 138kV	FROM BUS 79005 TO BUS 65193 CKT 1 FROM BUS 79038 TO BUS 79001 CKT 1 FROM BUS 79046 TO BUS 66278 CKT 1	650 (EtW)
4	Intermountain - Gonder 230kV Pavant - Gonder 230kV	Intermountain – Gonder 230kV (Pavant) Utah_Nev - Gonder 230kV	FROM BUS 26041 TO BUS 64056 CKT 1 FROM BUS 64124 TO BUS 64056 CKT 1	245 (EtW)
5	Bonanza_West	Bonanza – Mona 345kV Upalco - Emmapark (Carbon) 138kV	FROM BUS 65193 TO BUS 65995 CKT 1 FROM BUS 66590 TO BUS 65520 CKT 1	735 (EtW)
6	TOT_2B	Sigurd - Glen Canyon 230kV Pinto- Four Corners 345kV	FROM BUS 66355 TO BUS 79031 CKT 1 FROM BUS 66235 TO BUS 14101 CKT 1	780
7	TOT_2C	Red Butte - Harry Allen 345kV	FROM BUS 66280 TO BUS 18002 CKT 1	300
8	Borah_West	Kinport – Midpoint 345kV Borah – Adelaide 345kV Borah – Adelaide 345kV AmFalls - Pleasant Valley 138kV AmFalls - Raft River 138kV	FROM BUS 60190 TO BUS 60235 CKT 1 FROM BUS 60060 TO BUS 60005 CKT 1 FROM BUS 60060 TO BUS 60006 CKT 2 FROM BUS 60020 TO BUS 60295 CKT 1 FROM BUS 60020 TO BUS 61900 CKT 1	2307 (EtW)
9	Bridger_West	Jim Bridger – Borah 345kV Jim Bridger – Goshen 345kV Jim Bridger – Kinport 345kV	FROM BUS 60090 TO BUS 60060 CKT 1 FROM BUS 60092 TO BUS 65665 CKT 1 FROM BUS 60091 TO BUS 60190 CKT 1	2200 (EtW)
10	C	Ben Lomond – Borah 345kV Treasureton – Brady 230kV Grace – Goshen 161kV Malad – AmFalls 138kV	FROM BUS 65135 TO BUS 60060 CKT 1 FROM BUS 66565 TO BUS 60073 CKT 1 FROM BUS 65560 TO BUS 65670 CKT 1 FROM BUS 65920 TO BUS 60020 CKT 1	1000

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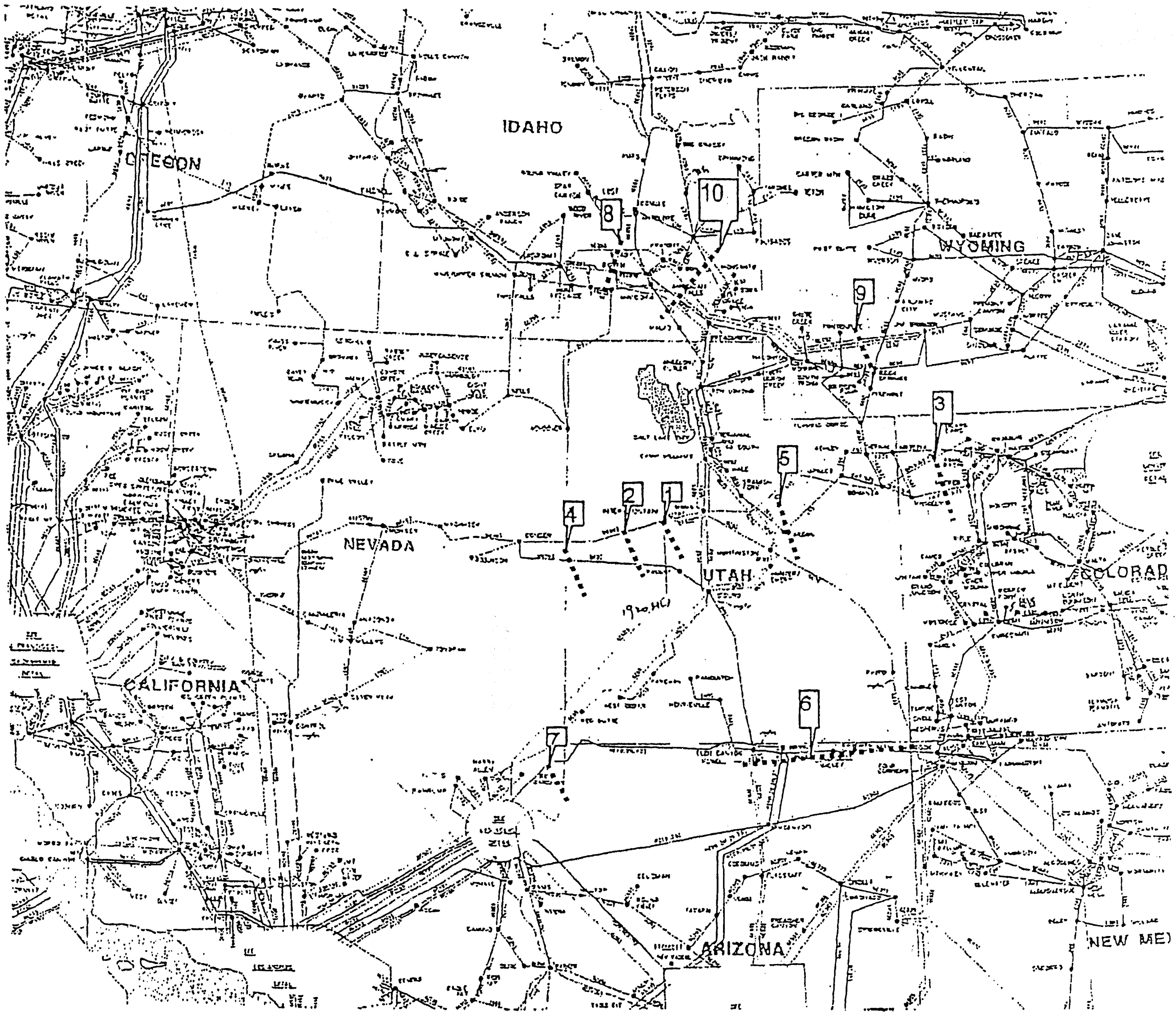
Figure A. WSCC Network with Paths



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Appendix B

FCITC Single Study

*** MUST 4 02 02 *** THU, JAN 10 2002 11.51 ***

WESTERN SYSTEMS COORDINATING COUNCIL

2002 HS2-SA BASE CASE

Subsys File C \Project\ESC\Mona\Mona.sub

Monit File C \Project\ESC\Mona\Mona mon

Contin File C \Project\ESC\Mona\Mona.con

Exclud File C \Project\ESC\Mona\Mona.exc

Study transfer. From MONA_345 To WEST . Transfer level - 600.0 MW

Base Case violations report ordered by transfer capability. Total 755 violations

Interface-1	Interface	9	Borah_West	Init.Flow=	706.98	TDF= 0.4509
Interface-2	Interface	10	Bridger_West	Init.Flow=	1818.85	TDF= 0.1089
Interface-3	Interface	11	C	Init.Flow=	-630.20	TDF= 0.3511
Interface-4	Interface	4	Int_Gonder_P	Init.Flow=	120.39	TDF= 0.3653
Interface-5	Interface	2	Interant_Gon	Init.Flow=	57.60	TDF= 0.2102
Interface-6	Interface	1	Intermnt_Mon	Init.Flow=	-325.14	TDF=-0.2102
Interface-7	Interface	3	TOT_1A	Init.Flow=	318.13	TDF=-0.0861
Interface-8	Interface	6	TOT_2B	Init.Flow=	77.57	TDF= 0.1244
Interface-9	Interface	7	TOT_2C	Init.Flow=	151.18	TDF= 0.0000

ll	NITC	IntFce1	IntFce2	IntFce3	IntFce4	IntFce5	IntFce6	IntFce7	IntFce8	IntFce9	Limiting constraint	Base Flow	MW Rating	PTDF
217	341.2	860.8	1856 0	-510.4	245.0	129.3	-396.8	288.8	120.0	151.2	Interface 4 Int_Gonder_P	120.4	245.0	0.36527
601	577 4	967 3	1881 7	-427.5	331 3	178 9	-446.5	268.4	149.4	151.2	64059 HUMBOLDT 345 64061 IDAHO-NV 345 1	-288.4	-645.0	-0.61767

Study transfer From MONA_345 To WEST . Transfer level - 600.0 MW

Violations report ordered by transfer capability. Total 755 violations

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Interface-1	Interface	9	Borah_West	Init.Flow=	706.98 TDF= 0.4509
Interface-2	Interface	10	Bridger_West	Init.Flow=	1818.85 TDF= 0.1089
Interface-3	Interface	11	C	Init.Flow=	-630.20 TDF= 0.3511
Interface-4	Interface	4	Int_Gondar_P	Init.Flow=	120.39 TDF= 0.3653
Interface-5	Interface	2	Intermnt_Gon	Init.Flow=	57.60 TDF= 0.2102
Interface-6	Interface	1	Intermnt_Mon	Init.Flow=	-325.14 TDF=-0.2102
Interface-7	Interface	3	TOT_1A	Init.Flow=	318.13 TDF=-0.0861
Interface-8	Interface	6	TOT_2B	Init.Flow=	77.57 TDF= 0.1244
Interface-9	Interface	7	TOT_2C	Init.Flow=	151.18 TDF= 0.0000

N	FCITC	IntFce1	IntFce2	IntFce3	IntFce4	IntFce5	IntFce6	IntFce7	IntFce8	IntFce9	L: Limiting constraint C: Contingency description	Ncon	PreShift Flow	MW Rating	TDF	LODF	PTDF	=Base Case Flow= Init	Final
1	15 7	714 1	1820.6	-624 7	126.1	60.9	-328.4	316.8	79.5	151.2	L: Interface 4 Int_Gondar_P		235.4	245.0	0.61157		0.36527	120.4	126.1
											C:64059 HUMBOLDT 345 64061 IDAHO-NV 345 1	22							
											Open 64059 HUMBOLDT 345 64061 IDAHO-NV 345 1					-0.39876	-0.61767	-288.4	-298.1
2	99 7	751.9	1829.7	-595.2	156.8	78.6	-346.1	309.6	90.0	151.2	L:64059 HUMBOLDT 345 64080 HUMBOLDT 120 1		127.1	150.0	0.23004		0.02506	50.9	53.4
											C:64032 COYOTECR 345 64059 HUMBOLDT 345 1	13							
											Open 64032 COYOTECR 345 64059 HUMBOLDT 345 1					-0.34589	-0.59261	-220.3	-279.4
3	131 6	766.3	1833 2	-584.0	168.4	85 3	-352.8	306.8	93.9	151.2*L:	Interface 4 Int_Gondar_P		176.9	245.0	0.51736		0.36527	120.4	168.4
											C:64032 COYOTECR 345 64059 HUMBOLDT 345 1	13							
											Open 64032 COYOTECR 345 64059 HUMBOLDT 345 1					-0.25663	-0.59261	-220.3	-298.3
7	226 5	809.1	1843.5	-550.7	203.1	105.2	-372.7	298.6	105.8	151.2	L: Interface 2 Intermnt_Gon		121.4	200.0	0.34687		0 21016	57.6	105.2
											C:64059 HUMBOLDT 345 64061 IDAHO-NV 345 1	22							
											Open 64059 HUMBOLDT 345 64061 IDAHO-NV 345 1					-0.22132	-0.61767	-288.4	-428.3
217	341 2	860.8	1856.0	-510.4	245.0	129.3	-396.8	288.8	120.0	151.2	L: Interface 4 Int_Gondar_P		120.4	245.0	0.36527				
											Base Case								
343	350.4	865 0	1857.0	-507 2	248.4	131.3	-398.8	288.0	121.2	151.2*L:	Interface 2 Intermnt_Gon		100.8	200.0	0.28307		0.21016	57.6	131.3
											C.66210 PAVANT 230 66345 SIGURD 230 1	169							
											Open 66210 PAVANT 230 66345 SIGURD 230 1					-0.47002	-0.15511	-91.9	-146.3
363	381 7	879 1	1860 4	-496 2	259 8	137.8	-405.4	285.3	125.1	151.2	L:64056 GONDER 230 64124 UTAH-NEV 230 1		-114.0	-215.0	-0.26471		-0.15511	-62.8	-122.0
											C:64059 HUMBOLDT 345 64061 IDAHO-NV 345 1	22							
											Open 64059 HUMBOLDT 345 64061 IDAHO-NV 345 1					0.17744	-0.61767	-288.4	-524.2
365	395 9	885 5	1862.0	-491 2	265 0	140.8	-408.3	284.0	126.8	151.2	L:64059 HUMBOLDT 345 64061 IDAHO-NV 345 1		-400.5	-645.0	-0.61767		-0.61767	-288.4	-532.9
											C:64017 BRDRTNPS 345 64058 HIL TOP 345 1	11							
											Open 64017 BRDRTNPS 345 64058 HIL TOP 345 1					0.46939	-0.00000	-238.8	-238.8
368	399 0	886 9	1862 3	-490.1	266.1	141.5	-409.0	283.8	127.2	151.2*L:	L:64059 HUMBOLDT 345 64061 IDAHO-NV 345 1		-398.6	-645.0	-0.61767		-0.61767	-288.4	-534.8
											C:64017 BRDRTNPS 345 64018 BRDRTHN 345 1	10							
											Open 64017 BRDRTNPS 345 64018 BRDRTHN 345 1					-0.46939	0.00000	234.7	234.7
371	425 8	899 0	1865 2	-480 7	275.9	147.1	-414.6	281.5	130.6	151.2	L:64115 TRACY 345 64207 TRACY E 50.0 1		187.1	280.0	0.21810		0.16065	108.3	176.7
											C:64077 MIRA LMA 345 64115 TRACY 345 1	23							
											Open 64077 MIRA LMA 345 64115 TRACY 345 1					-0.37494	-0.15322	-210.2	-275.4
[illegible]78	469 8	918 8	1870 0	-465 2	292.0	156.3	-423.9	277.7	136.0	151.2	L:64043 FALCON 345 64042 FALCON 120 1		-0.2	-150.0	-0.31886		-0.03167	42.8	28.0

											C:64032 COYOTECR 345 64130 VALMY 345 1	14						
											Open 64032 COYOTECR 345 64130 VALMY 345 1				-0.49009	0.58600	87.8	161.1
383	521 9	942.3	1875.7	-446.9	311.0	167.3	-434.8	273.2	142.5	151.2	L:64032 COYOTECR 345 64030 COYOTEC2 120 1	83.8	150.0	0.12683		0.00413	65.4	67.6
											C:64032 COYOTECR 345 64130 VALMY 345 1	14						
											Open 64032 COYOTECR 345 64130 VALMY 345 1				0.20937	0.58600	87.8	393.7
384	525 6	944 0	1876.1	-445.6	312.4	168.1	-435.6	272.9	143.0	151.2	L:64056 GONDER 230 64310 GONDER 345 1	88.7	400.0	0.59221		0.36527	-17.2	174.8
											C:64059 HUMBOLDT 345 64061 IDAHO-NV 345 1	22						
											Open 64059 HUMBOLDT 345 64061 IDAHO-NV 345 1				-0.36742	-0.61767	-288.4	-613.0
385	535 9	948 6	1877.2	-442.0	316.1	170.2	-437.8	272.0	144.3	151.2	L:64032 COYOTECR 345 64059 HUMBOLDT 345 1	-327.4	-645.0	-0.59261		-0.59261	-220.3	-537.9
											C:64017 BRDRTNPS 345 64058 HIL TOP 345 1	11						
											Open 64017 BRDRTNPS 345 64058 HIL TOP 345 1				0.44850	-0.00000	-238.8	-238.8
388	539 0	950 0	1877 5	-441.0	317.3	170.9	-438.4	271.7	144.6	151.2*	L:64032 COYOTECR 345 64059 HUMBOLDT 345 1	-325.6	-645.0	-0.59261		-0.59261	-220.3	-539.7
											C:64017 BRDRTNPS 345 64018 BRDRTWN 345 1	10						
											Open 64017 BRDRTNPS 345 64018 BRDRTWN 345 1				-0.44850	0.00000	234.7	234.7
402	570 4	964 1	1880 9	-429.9	328.7	177.5	-445.0	269.0	148.5	151.2*	L:64056 GONDER 230 64124 UTAH-NEV 230 1	-87.9	-215.0	-0.22277		-0.15511	-62.8	-151.3
											C:64032 COYOTECR 345 64059 HUMBOLDT 345 1	13						
											Open 64032 COYOTECR 345 64059 HUMBOLDT 345 1				0.11418	-0.59261	-220.3	-558.3
601	577 4	967.3	1881.7	-427.5	331.3	178.9	-446.5	268.4	149.4	151.2	L:64059 HUMBOLDT 345 64061 IDAHO-NV 345 1	-288.4	-645.0	-0.61767				
											Base Case							
751	590.9	973.4	1883.2	-422.7	336.2	181.8	-449.3	267.3	151.1	151.2	L:64128 VAL ROAD 345 64125 VAL RD N 120 2	218.5	280.0	0.10407		0.06211	160.9	197.7
											C:64077 MIRA LMA 345 64115 TRACY 345 1	23						
											Open 64077 MIRA LMA 345 64115 TRACY 345 1				-0.27383	-0.15322	-210.2	-300.7

Generation/Load adjustments in the [MONA_345] sub-system. Type PartFactDef.
Total change 600.0 MW. ((Load Changes are shown with negative sign)

Bus#	BusName	KV	NAr	Zne	ParFact	Pload	Pmin	Pmax	Pgen	Reserv-	Reserv+	NewGen	Change	Viol
65995	MONA	345	65	656	600 00	0.0	-999.0	999.0	1.0	1000.0	998.0	601.0	600.0	
	Total				600.00	0.0	-999.0	999.0	1.0	1000.0	998.0			

Maximum transfers without violating limits with specified participation factors
Import= 1000.0 MW, Export= 998.0 MW

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010210

FCITC Single Study

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*** MUST 4 02 02 ***   THU, JAN 03 2002  12 35 ***
     WESTERN SYSTEMS COORDINATING COUNCIL
     2003 HS2-SA BASE CASE
Subsys File C \Project\ESC\Mona\Mona.sub
Monit File  C \Project\ESC\Mona\Mona mon
Contin File C \Project\ESC\Mona\Mona con
Exclud File none
```

Study transfer From MONA_345 To EAST . Transfer level - 600.0 MW

**** No Base Case Violations have been found

Study transfer From MONA_345 To EAST . Transfer level - 600.0 MW

Violations report ordered by transfer capability Total 4 violations

Interface-1	Interface	5	Bonanza_West	Init.Flow=	606.48 TDF=-0.4161
Interface-2	Interface	12	Borah_West	Init.Flow=	706.98 TDF= 0.0431
Interface-3	Interface	13	Bridger_West	Init.Flow=	1160.22 TDF=-0.0922
Interface-4	Interface	14	C	Init.Flow=	-630.20 TDF= 0.2092
Interface-5	Interface	4	Int_Gonder_P	Init.Flow=	120.39 TDF= 0.0435
Interface-6	Interface	2	Intermnt_Gon	Init.Flow=	57.60 TDF= 0.0110
Interface-7	Interface	3	TOT_2A	Init.Flow=	318.13 TDF=-0.4383
Interface-8	Interface	6	TOT_2B	Init.Flow=	77.57 TDF= 0.2123
Interface-9	Interface	7	TOT_2C	Init Flow=	151.18 TDF= 0.0000

N	FCITC	IntFce1	IntFce2	IntFce3	IntFce4	IntFce5	IntFce6	IntFce7	IntFce8	IntFce9	L: Limiting constraint / C: Contingency description	Ncon	PreShift Flow	MW Rating	TDF	LODF	PTDF	*Base Case Flow* Init	Final
1	499 5	398 7	728 5	1114 2	-525 7	142.1	73 1	99.2	183.6	151.2	L:65192 BONANZA 138 66278 RANGELY 138 1		141.7	160.0	0.03667		0.04254	40.1	61.3
											C 65192 BONANZA 138 65193 BONANZA 345 1	55							
											Open 65192 BONANZA 138 65193 BONANZA 345 1					0.38441	-0.01526	264.3	256.7
2	546 4	379 2	730 5	1109 8	-515 9	144.1	74.5	78.6	193.6	151.2	L:73212 WELD LN 230 70471 WELD PS 230 1		422.0	500.0	0 14280		0 12403	329.9	397 6
											C:73078 HARMONY 230 73199 TIMBERLN 230 1	242							
											Open 73078 HARMONY 230 73199 TIMBERLN 230 1					-0.35953	-0.05223	-256 2	-284.7

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ABB

Generation/Load adjustments in the [MONA_345] sub-system. Type PartFactDef.

Total change 600 0 MW (! Load Changes are shown with negative sign)

Bus#	BusName	KV	HAr	Zne	ParFact	Pload	Pmin	Pmax	Pgen	Reserv-	Reserv+	NewGen	Change	Viol
65995	MONA	345	65	656	600.00	0.0	-999 0	999.0	1.0	1000.0	998.0	601.0	600.0	
	Total				600 00	0 0	-999.0	999.0	1.0	1000.0	998.0			

Maximum transfers without violating limits with specified participation factors

Import= 1000 0 MW Export= 998 0 MW

10/2/02

FCITC Single Study

** MUST 4 02 02 *** THU JAN 03 2002 12:29 ***
WESTERN SYSTEMS COORDINATING COUNCIL
2003 HS2-SA BASE CASE
Subsys File C \Project\ESC\Mona\Mona sub
Monit File C:\Project\ESC\Mona\Mona mon
Contin File C \Project\ESC\Mona\Mona con
Exclud File none

Study transfer From MONA_345 **To NORTH_WEST** . Transfer level - 600.0 MW

* * No Base Case Violations have been found

Study transfer From MONA_345 To NORTH_WEST . Transfer level - 600.0 MW

Violations report ordered by transfer capability Total 3 violations

Interface-1	Interface	9	1Idaho_Sierr	Init.Flow=	288.37 TDF=-0.0922
Interface-2	Interface	5	Bonanza_West	Init Flow=	606.48 TDF=-0.1557
Interface 3	Interface	12	Borah_West	Init Flow=	706.98 TDF= 0.4119
Interface-4	Interface	13	Bridger_West	Init.Flow=	1160.22 TDF= 0.0974
Interface-5	Interface	14	C	Init.Flow=	-630.20 TDF= 0.4979
Interface-6	Interface	4	Int_Gonder_P	Init Flow=	120 39 TDF= 0.0922
Interface-7	Interface	2	Intermnt_Gon	Init.Flow=	57.60 TDF= 0.0590
Interface 8	Interface	6	TOT_2B	Init.Flow=	77.57 TDF= 0.1832
Interface-9	Interface	7	TOT_2C	Init Flow=	151 18 TDF= 0.0000

N	FCITC	Intfce1	Intfce2	Intfce3	Intfce4	Intfce5	Intfce6	Intfce7	Intfce8	Intfce9	L. Limiting constraint / C: Contingency description	Ncon	PreShift Flow	MW Rating	TDF	LODF	PTDF	=Base Case Flow= Init	Final
1	173 5	272 4	573 5	778 4	1177 1	-543 8	136 4	67 8	109.4	151 2	L. Interface 4 Int_Gonder_P		235.4	245 0	0.05545		0 09222	120 4	136 4
											C.64059 HUMBOLDT 345 64061 IDAHO-NV 345 1	22							
											Open 64059 HUMBOLDT 345 64061 IDAHO-NV 345 1					-0 39876	0 09222	-288 4	-272 4

Generation/Load adjustments in the [MONA_345] sub-system. Type PartFactDef.
Total change 600 0 MW (! Load Changes are shown with negative sign)

ABB

P94

1023

Bus#	BusName	kV	NAr	Zne	ParFact	Pload	Pmin	Pmax	Pgen	Reserv-	Reserv+	NewGen	Change	Viol
65995	MONA	345	65	656	600 00	0 0	-999.0	999.0	1.0	1000.0	998.0	601.0	600.0	
	Total				600 00	0.0	-999.0	999.0	1.0	1000.0	998.0			

Maximum transfers without violating limits with specified participation factors

Import= 1000 0 MW Export= 998 0 MW

FCITC Single Study

MUST 4 02 02 ** THU JAN 03 2002 13:01 ***
WESTERN SYSTEMS COORDINATING COUNCIL
2003 HS2 SA BASE CASE
Subsys File C \Project\ESC\Mona\Mona sub
Monit File C \Project\ESC\Mona\Mona mon
Contin File C \Project\ESC\Mona\Mona con
Exclud File none

Study transfer From MONA_345 To SOUTH - Transfer level - 600.0 MW

No Base Case Violations have been found

Study transfer From MONA_345 To SOUTH Transfer level - 600 0 MW

Violations report ordered by transfer capability Total 1 violations

Interface 1	Interface	5	Bonanza_West	Init Flow=	606 48	TDF=-0 1946
Interface 2	Interface	12	Borah_West	Init Flow=	706 98	TDF= 0 3098
Interface 3	Interface	13	Bridger_West	Init Flow=	1160 22	TDF= 0 0395
Interface 4	Interface	14	C	Init Flow=	-630 20	TDF= 0 3028
Interface 5	Interface	4	Int_Conder_P	Init Flow=	120 39	TDF= 0 0611
Interface 6	Interface	2	Intermnt_Con	Init Flow=	57 60	TDF= 0 0450
Interface 7	Interface	3	TOT_1A	Init Flow=	318 13	TDF=-0 1841
Interface 8	Interface	6	TOT_2B	Init Flow=	77 57	TDF= 0 3825
Interface 9	Interface	7	TOT_2C	Init Flow=	151 18	TDF= 0 0000

N	FCITC	Intfce1	Intfce2	Intfce3	Intfce4	Intfce5	Intfce6	Intfce7	Intfce8	Intfce9	L: Limiting constraint C Contingency description	Ncon	PreShift Flow	MW Rating	TDF	LODF	PTDF	=Base Case Flow= Init	Final
1	261 8	555 5	788 1	1170 6	-550 9	136 4	69 4	269 9	177 7	151 2	L: Interface 4 Int_Conder_P		235 4	245 0	0 03675		0 06112	120 4	136 4
											C 64059 HUMBOLDT 345 64061 IDAHO-NV 345 1	22							
											Open 64059 HUMBOLDT 345 64061 IDAHO NV 345 1					-0 39876	0 06112	-288 4	272 4

Generation/Load adjustments in the [MONA_345] sub-system Type PartFactDef
Total change 600 0 MW (! Load Changes are shown with negative sign)

ABB

P96

10215

Bus#	BusName	KV	NAr	Zne	ParFact	Pload	Pmin	Pmax	Pgen	Reserv-	Reserv+	NewGen	Change	Viol
65995	HONA	345	65	656	600.00	0.0	-999.0	999.0	1.0	1000.0	998.0	601.0	600.0	
	Total				600.00	0.0	-999.0	999.0	1.0	1000.0	998.0			

Maximum transfers without violating limits with specified participation factors

Import= 1000.0 MW. Export= 998.0 MW

FCITC Single Study

MUST 4 02 02 ** THU JAN 03 2002 13 05 ***
WESTERN SYSTEMS COORDINATING COUNCIL
2003 HS2-SA BASE CASE
Subsys File C \Project\ESC\Mona\Mona sub
Monit File C \Project\ESC\Mona\Mona mon
Contin File C \Project\ESC\Mona\Mona con
Exclud File none

Study transfer From MONA_345 To SOUTH_WEST . Transfer level - 600.0 MW

* No Base Case Violations have been found

Study transfer From MONA_345 To SOUTH_WEST . Transfer level - 600.0 MW

Violations report ordered by transfer capability Total 3 violations

Interface 1	Interface	5	Bonanza_West	Init.Flow=	606 48	TDF=-0.1948
Interface-2	Interface	12	Borah_West	Init Flow=	706.98	TDF= 0.3292
Interface-3	Interface	13	Bridger_West	Init Flow=	1160.22	TDF= 0.0440
Interface-4	Interface	14	C	Init Flow=	-630.20	TDF= 0.3184
Interface-5	Interface	4	Int_Gonder_P	Init Flow=	120.33	TDF= 0.0645
Interface-6	Interface	2	Intermnt_Gon	Init Flow=	57.60	TDF= 0.0463
Interface 7	Interface	3	TOT_1A	Init Flow=	318.13	TDF=-0.1826
Interface 8	Interface	6	TOT_2B	Init Flow=	77 57	TDF= 0 3620
Interface-9	Interface	7	TOT_2C	Init.Flow=	151 18	TDF= 0.0000

N	FCITL	IntFce1	IntFce2	IntFce3	IntFce4	IntFce5	IntFce6	IntFce7	IntFce8	IntFce9	L. Limiting constraint / C: Contingency description	Ncon	PreShift Flow	MW Rating	TDF	LODF	PTDF	Base Case Flows Init	Base Case Flows Final
1	248 0	558 2	788 6	1171 1	-551 2	136 4	69 1	272 8	167 3	151.2	L: Interface 4 Int_Gonder_P		235.4	245 0	0.03879		0 06452	120 4	136 4
											C.64059 HUMBOLDT 345 64061 IDAHO-NV 345 1	22							
											Open 64059 HUMBOLDT 345 64061 IDAHO-NV 345 1					-0.33876	0 06452	-288 4	-272 4

Generation/Load adjustments in the (MONA_345) sub-system Type PartFactDef.
Total change 600 0 MW ((Load Changes are shown with negative sign)

ABB

P98

Bus#	BusName	KV	NAr	Zne	ParFact	Pload	Pmin	Pmax	Pgen	Reserv-	Reserv+	NewGen	Change	Viol
65995	HONA	345	65	656	600.00	0.0	-999.0	999.0	1.0	1000.0	998.0	**601.0**	**600.0**	
	Total				600.00	0.0	-999.0	999.0	1.0	1000.0	998.0			

Maximum transfers without violating limits with specified participation factors

Import= 1000 0 MW Export= 998 0 MW

AppendixC

AC FCITC Single Study

```
*** MUST 4 02.02 ***  THU, JAN 10 2002  11:31 ***
     WESTERN SYSTEMS COORDINATING COUNCIL
     2003 HS2-SA BASE CASE
Subsys.File C \Project\ESC\Mona\Mona.sub
Monit.File  C \Project\ESC\Mona\Mona.mon
Contin File C.\Project\ESC\Mona\Mona.con
Exclud File C \Project\ESC\Mona\Mona.exc

 Study transfer level -     1000.0 MW. Total violations: 2208
 First violation      -       15.7 MW.
```

Study transfer. From MONA_345 To WEST . **Transfer level - 1000.0 MW**

AC FCITC	DC FCITC	Delta FCITC	L. / C.	Limiting constraint / Contingency description	Ncon	PreShft MVA/MW	PostShf MVA/MW	Rating	AC_TDF Average	DC_TDF
0 7	15 7	-15.1	L:	Interface 4 Int_Gonder_P		244.6	244.8	245.0	0.31243	0.61157
			C.	64059 HUMBOLDT 345 64061 IDAHO-NV 345 1	22					
				Open 64059 HUMBOLDT 345 64061 IDAHO-NV 345 1						
128 8	99 7	29.1	L:	64059 HUMBOLDT 345 64080 HUMBOLDT 120 1		130.7	149.6	150.0	0.14645	0.23004
			C:	64032 COYOTECR 345 64059 HUMBOLDT 345 1	13					
				Open 64032 COYOTECR 345 64059 HUMBOLDT 345 1						
145 6	131.6	14 0	L.	Interface 4 Int_Gonder_P		182.4	244.2	245.0	0.42436	0.51736
			C:	64032 COYOTECR 345 64059 HUMBOLDT 345 1	13					
				Open 64032 COYOTECR 345 64059 HUMBOLDT 345 1						
254 8	226.5	28 2	L	Interface 2 Intermnt_Gon		124.8	200.7	200.0	0.29802	0.34687
			C.	64059 HUMBOLDT 345 64061 IDAHO-NV 345 1	22					
				Open 64059 HUMBOLDT 345 64061 IDAHO-NV 345 1						
394 7	341.2	53.5	L:	Interface 4 Int_Gonder_P		120.4	243.9	245.0	0.31305	0.36527
				Base Case						
422 8	350 4	72 4	L:	Interface 2 Intermnt_Gon		99.8	199.2	200.0	0.23503	0.28307

			C.66210 PAVANT 230 66345 SIGURD 230 1	169					
			Open 66210 PAVANT 230 66345 SIGURD 230 1						
272 7	381.7	-109.0	L 64056 GONDER 230 64124 UTAH-NEV 230 1		117.3	199.3	215.0	0.30068	-0.26471
NotConv			C 64059 HUMBOLDT 345 64061 IDAHO-NV 345 1	22					
			Open 64059 HUMBOLDT 345 64061 IDAHO-NV 345 1						
368 1	395.9	-27.8	L 64059 HUMBOLDT 345 64061 IDAHO-NV 345 1		402.5	610.8	645.0	0.56606	-0.61767
NotConv			C 64017 BRDRTNPS 345 64058 HIL TOP 345 1	11					
			Open 64017 BRDRTNPS 345 64058 HIL TOP 345 1						

AC FCITC Single Study

```
*** MUST 4.02.02 ***  THU, JAN 10 2002  10:15 ***
     WESTERN SYSTEMS COORDINATING COUNCIL
     2003 HS2-SA BASE CASE
Subsys.File C:\Project\ESC\Mona\Mona.sub
Monit.File  C:\Project\ESC\Mona\Mona.mon
Contin.File C:\Project\ESC\Mona\Mona.con
Exclud.File C:\Project\ESC\Mona\Mona.exc

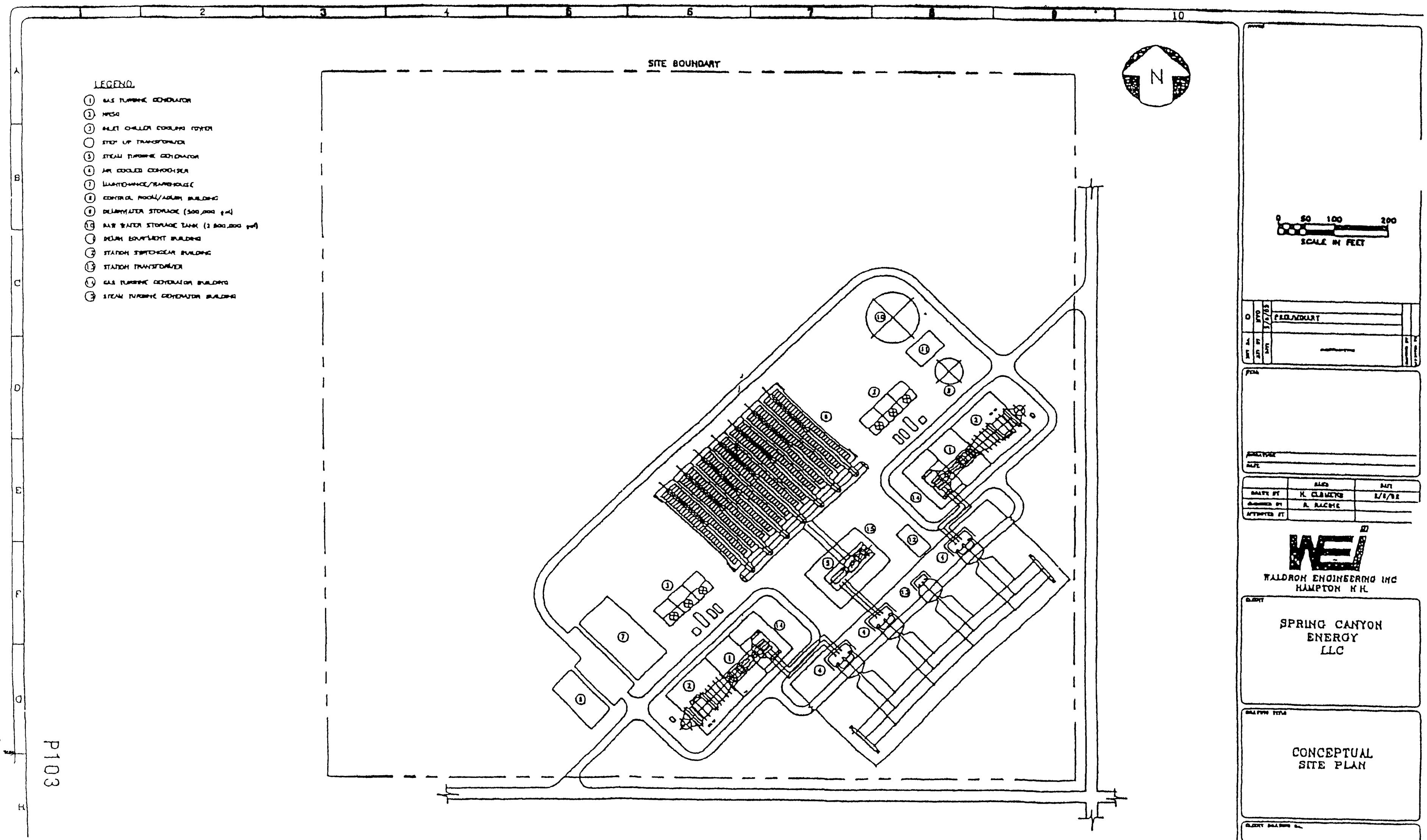
 Study transfer level -     1000.0 MW. Total violations: 7
 First violation      -      499.5 MW.

Study transfer. From MONA_345          To EAST          . Transfer level -   1000.0 MW

     AC      DC     Delta L: Limiting constraint                       PreShft PostShf           AC_TDF    DC_TDF
   FCITC   FCITC   FCITC C: Contingency description               Ncon MVA/MW  MVA/MW  Rating  Average
   602.5   499.5   103.0 L:65192 BONANZA  138 66278 RANGELY  138 1       137.9   160.3   160.0  0.03709  0.03667
                         C:65192 BONANZA  138 65193 BONANZA  345 1    55
                           Open 65192 BONANZA  138 65193 BONANZA  345 1
```

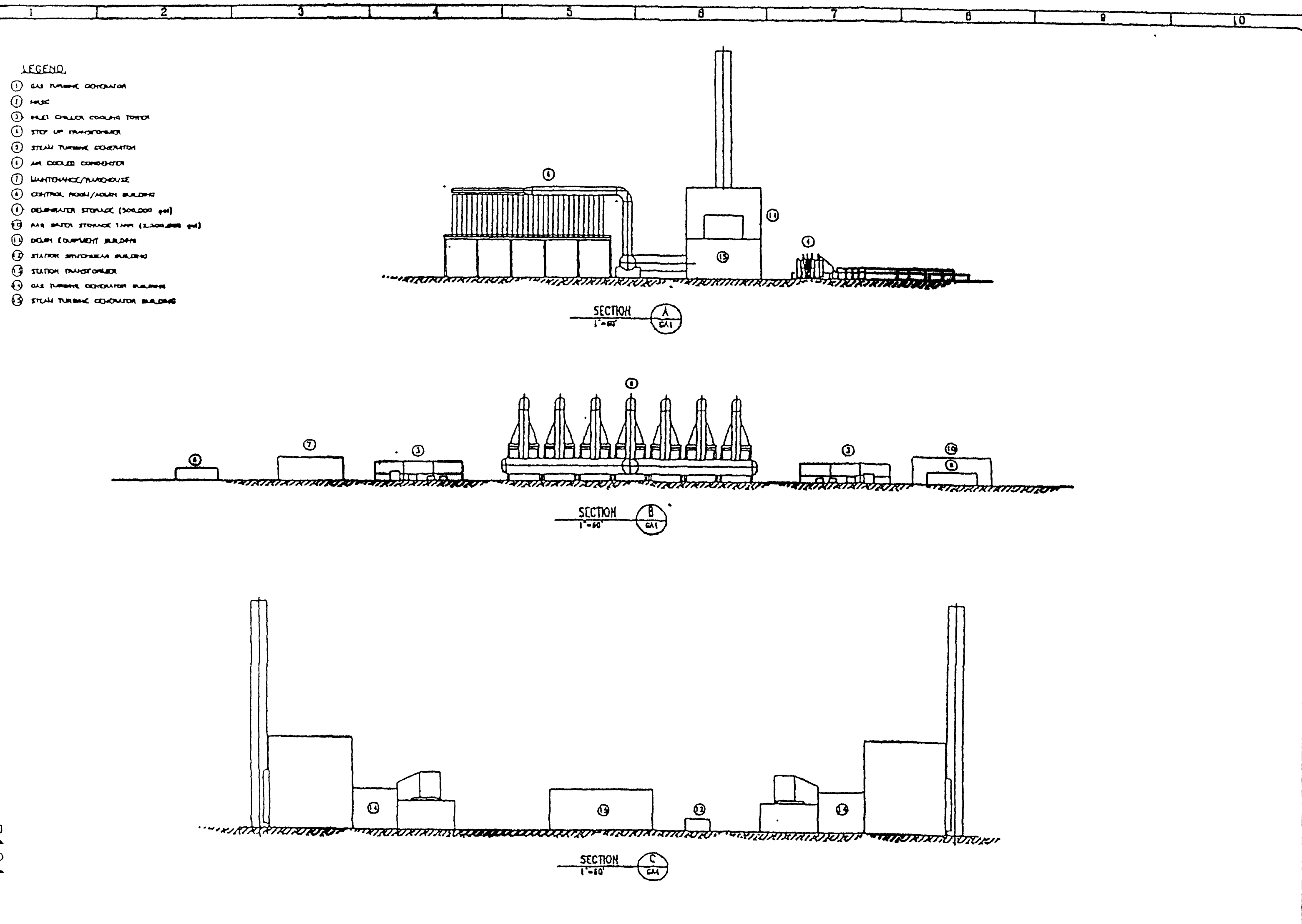
P102

1024


SITE BOUNDARY
LEGEND
1 GAS TURBINE GENERATOR
2 HRSG
3 INLET CHILLER COOLING TOWER
STEP UP TRANSFORMER
5 STEAM TURBINE GENERATOR
6 AIR COOLED CONDENSER
7 MAINTENANCE/WAREHOUSE
8 CONTROL ROOM/ADMIN BUILDING
9 DEMINERALIZER STORAGE (500,000 gal)
10 RAW WATER STORAGE TANK (2,800,000 gal)
WATER EQUIPMENT BUILDING
STATION SWITCHGEAR BUILDING
13 STATION TRANSFORMER
14 GAS TURBINE GENERATOR BUILDING
STEAM TURBINE GENERATOR BUILDING
N
0 50 100 200
SCALE IN FEET
PRELIMINARY
K. CLEMENS
R. RACINE
WEI
WALDRON ENGINEERING INC
HAMPTON N.H.
SPRING CANYON
ENERGY
LLC
CONCEPTUAL
SITE PLAN

P103

10223



PRELIMINARY

WEI
WALDRON ENGINEERING INC.
HAMPTON, N.H.

SPRING CANYON
ENERGY
LLC

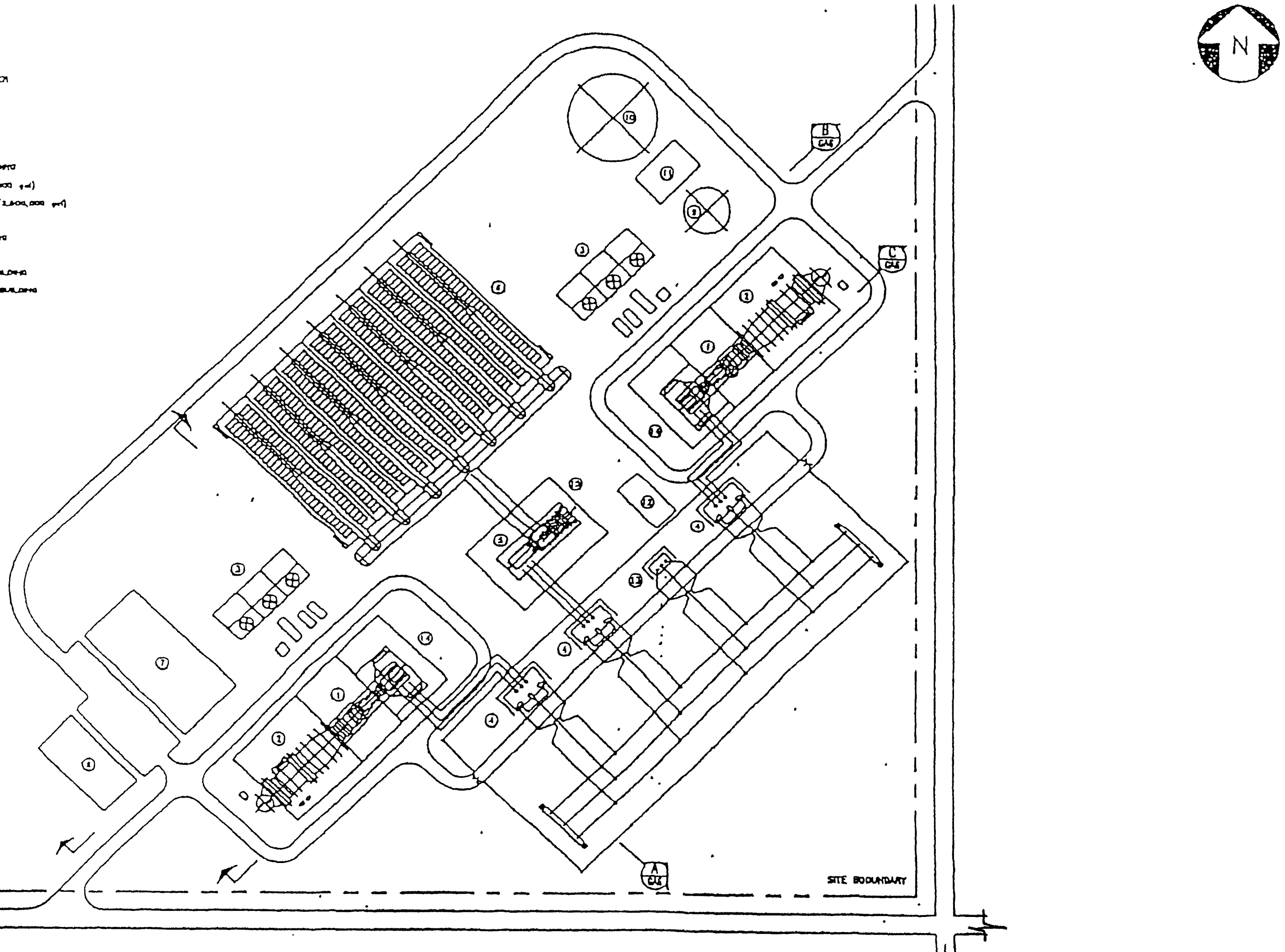
CONCEPTUAL
ELEVATIONS
GENERAL ARRANGEMENT

P104

10223

LEGEND

1. GAS TURBINE GENERATOR
2. HRSG
3. INLET CHILLER COOLING TOWER
4. STEP UP TRANSFORMER
5. STEAM TURBINE GENERATOR
6. AIR COOLED CONDENSER
7. MAINTENANCE/WAREHOUSE
8. CONTROL ROOM/ADMIN BUILDING
9. DEMINERALIZED WATER STORAGE (300,000 gal)
10. RAW WATER STORAGE TANK (2,800,000 gal)
11. DEMIN EQUIPMENT BUILDING
12. STATION SWITCHGEAR BUILDING
13. STATION TRANSFORMER
14. GAS TURBINE GENERATOR BUILDING
15. STEAM TURBINE GENERATOR BUILDING



WALDRON ENGINEERING INC
HAMPTON, N H

SPRING CANYON ENERGY LLC

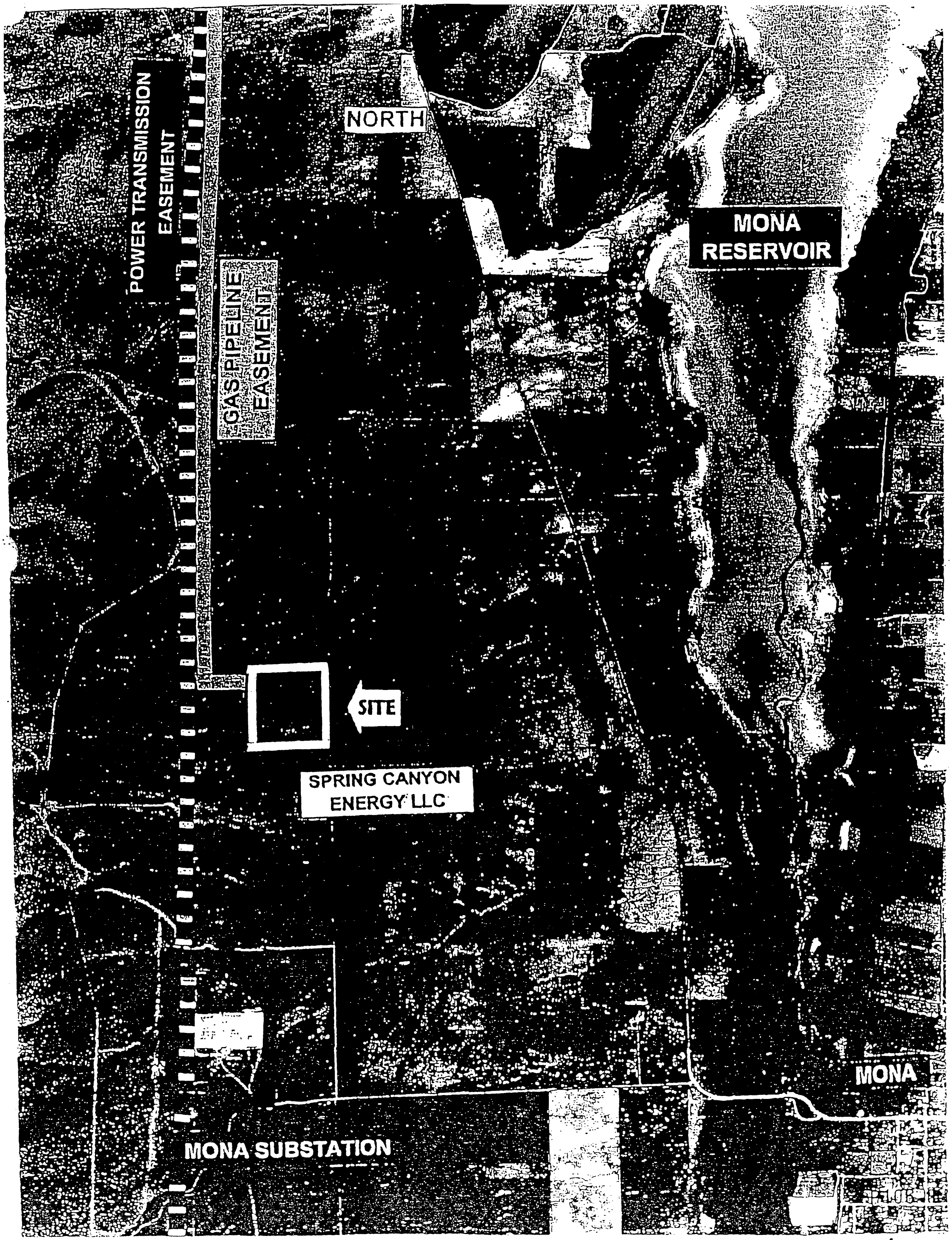
CONCEPTUAL
PLAN VIEW
GENERAL ARRANGEMENT

112-01-GA5-0

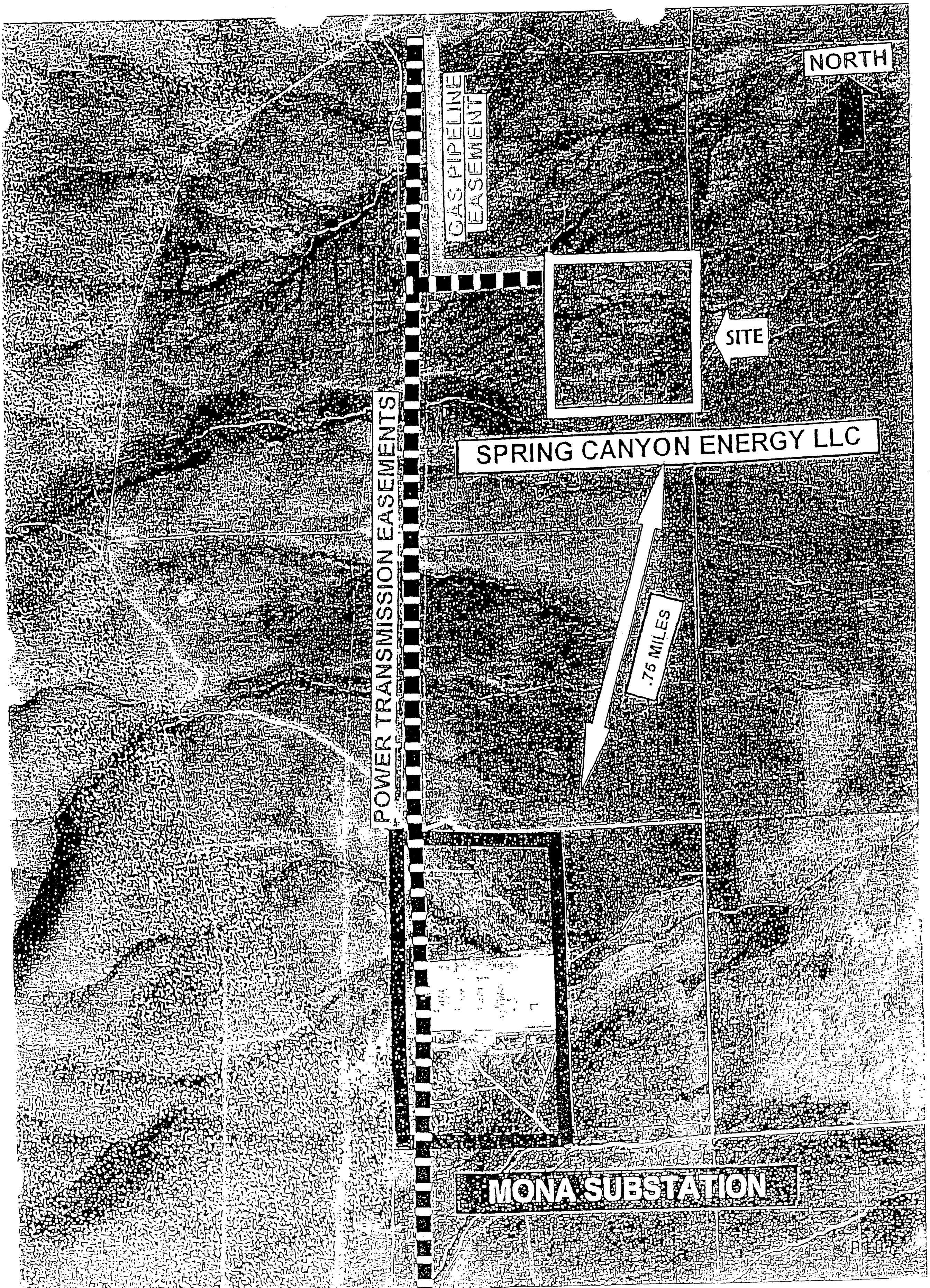
3/4/02

P105

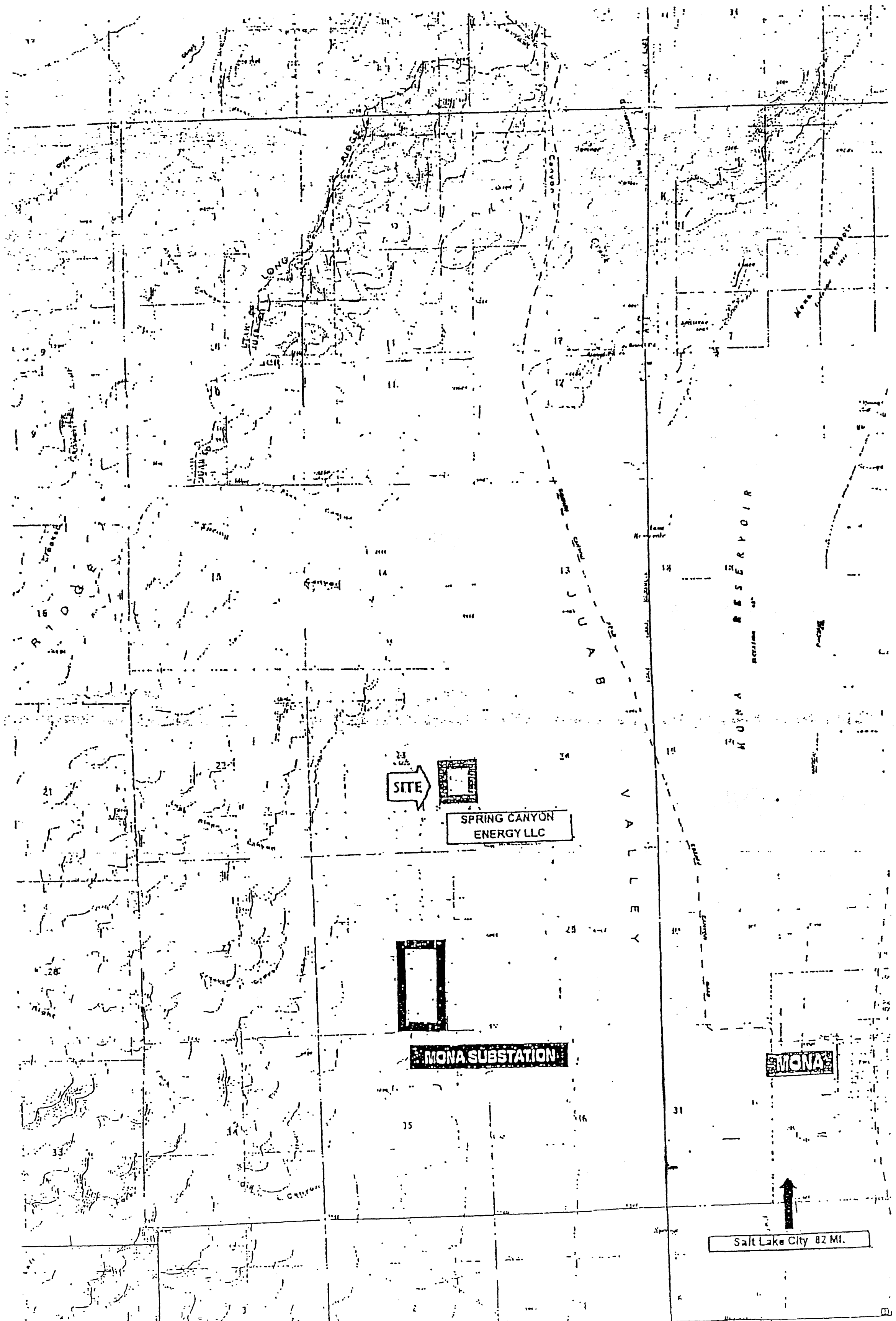
10234


NORTH
POWER TRANSMISSION EASEMENT
GAS PIPELINE EASEMENT
MONA RESERVOIR
SITE
SPRING CANYON ENERGY LLC
MONA
MONA SUBSTATION

10225


NORTH
GAS PIPELINE EASEMENT
SITE
SPRING CANYON ENERGY LLC
.75 MILES
POWER TRANSMISSION EASEMENTS
MONA SUBSTATION

10226


SITE
SPRING CANYON
ENERGY LLC
MONA SUBSTATION
MONA
Salt Lake City 82 MI.
JUAB VALLEY
MONA RESERVOIR
111°56'00" W
111°55'00" W
111°54'00" W
111°53'00" W
111°52'00" W
Scale 1:30,750
Contour Interval Varies: 20 ft, 40 ft

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10227

TED D. GUTH, Ph.D.

July 1, 2002

Mr. F. David Graeber
Spring Canyon Energy LLC
10440 North Central Expressway, Suite 1400
Dallas, Texas 75231

Re: Spring Canyon Energy LLC Application to the Utah Division of Air Quality

Dear Mr. Graeber:

Spring Canyon Energy, LLC submitted an application for an air permit to the Utah Division of Air Quality in February 2002. The application specifies that the facility will consist of two General Electric Model 7FA gas turbines firing only natural gas operating in a combined cycle configuration with heat recovery steam generators (HRSGs) and a single steam turbine generator. Subsequent correspondence has clarified that the configuration may utilize two independent steam turbine generators. The HRSGs will each be supplementary fired with natural gas duct burners to augment waste heat from the gas turbine exhaust. The gas turbines will be fitted with air inlet chillers, which allows for power augmentation when ambient temperature exceeds 59°F. The application further specifies that the Spring Canyon facility will have a nominal generation capacity of 539Mw at 59°F with duct firing and inlet chillers operating.

It is anticipated that the air permit will be issued with limitations consistent with the permit application, which are as follows:

> The gas turbine emissions will be controlled to 2.0 ppm NO_x and 4.0 ppm CO (while the original application specified CO to be controlled to 5 ppm, GE subsequently provided a letter guarantee of a CO emission limit of 4.0 ppm). While duct firing, CO will be limited to 9.0 ppm. Further discussions with GE provide the basis for the expectation that actual CO emissions will be less than 2.0 ppm.

As a result of these emission restrictions, the annual emissions from the facility will be limited to 97.2 tons of NO_x and 97 5 tons of CO. These pollutants will be continuously monitored and actual emissions continuously tracked throughout each year to help plan operations while ensuring compliance. Other criteria pollutant emissions are well below the 100 tons per year threshold for major emission sources. As a result, the Spring Canyon Energy facility is not considered a PSD major source.

These emission restrictions will provide a great deal of operational flexibility. However, if the facility were to operate at the GE guarantee of 4 0 ppm of CO, (rather than the expected ≤ 2 0 ppm level) the gas turbines would be limited to approximately 7200 hours per year This

619-670-3157
619-670-9454 (FAX)

3850 EL CANTO
SPRING VALLEY, CA 91977

is not expected since GE has cited much operational experience providing confidence that CO emissions will be in the range of 1.0 to 2.0 ppm.

The attached analysis from Waldron Engineering provides a view of the operational flexibility of the facility with both gas turbines operating, limiting CO to 97.5 tons per year, assuming both 4.0 ppm and 2.0 ppm. At the maximum expected CO emission level of 2.0 ppm, the gas turbines may be operational up to 8760 hours per year with the duct burners limited to 1388 hours per year. As gas turbine hours are reduced, available hours of duct firing increase. For example, if the gas turbines are limited to 6000 hours per year, the duct burners could be operated at their full output of 119 Mw for up to 2024 hours per year. Duct burners are typically operating in much the same way a peaking power plant operating approximately 10-20% of the year, therefore, even with the gas turbines operating the full year, the duct burners would be available to operate in a manner consistent with market projections. The duct burners could also be operated at a higher number of hours if their output was reduced. The analysis of operational flexibility associated with an emission level of 4.0 ppm is included to show that over 7200 hours of gas turbine operation is available under this most conservative and most unlikely scenario.

At the time that the original application was submitted, it was anticipated that the facility would not be required to obtain emission credits. However, the Utah Division of Air Quality has determined that approximately 225 tons of emission credits are indeed required in order to achieve to operational flexibility described above. Further, the applicant must have title to the emission credits prior to the public comment period associated with issuing the permit. An investigation of the emission credit market revealed that emission credits are readily available at a price ranging from $5,000 to $7,000 per ton or a total cost of $1.1 to $1.5 million. In order to defer this expense to a more appropriate time, the applicant has requested that the Utah Division of Air Quality issue a permit allowing the construction and operation of a single train (i.e. one gas turbine and one steam turbine generator), which does not trigger the need for emission credits. At such time that the applicant finds it prudent to secure title to the emission credits, the applicant will file an application to amend the requested permit.

At this time, I believe that the Utah Division of Air Quality has received all information necessary to issue a draft permit by the end of July 2002. At that time, a required 30-day public comment period will begin. Without significant public comment, the Utah Division of Air Quality will be able to issue the final permit without holding a public hearing. If the comment period results in significant comments, a public hearing will be held, which if necessary would mean that the final permit should be issued no later than September 2002.

It is my professional opinion that, as the proposed plant will have lower emissions than any plant currently operating in Utah, any opposition to the issuance of this permit will be without merit The Utah Division of Air Quality has indicated that the applicant has complied with all of its requirements and that no delays are envisioned with regards to the issuance of this permit. If you have any questions, please call me at your convenience at (619) 987-1111

Sincerely,

Dr Ted D Guth

Notice of Intent
Spring Canyon Energy, LLC

Submitted to

Utah DAQ

February 2002

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10230

Utah Division of Air Quality

New Source Review Section

Form 1
General Information

Application for: ☒ Initial Approval Order ☐ Approval Order Modification

A PERMIT TO CONSTRUCT MUST BE APPROVED BEFORE ANY ACTUAL WORK IS BEGUN ON THE FACILITIES. *This is not a stand alone document. Please refer to the Permit Application Instructions for* specific details required to complete the application. Please print or type all information requested. All information requested herein must be completed and submitted before an engineering review can be completed. Contact the Engineering Section of the Division of Air Quality with any questions at (801) 536-4000. Written inquiries may be addressed to: Division of Air Quality, Engineering Section, P.O. Box 144820, Salt Lake City, Utah 84114-4820.

General Owner and Facility Information	
1. Company name and address: Spring Canyon Energy, LLC PO Box 774000-359 Steamboat Springs CO 80477 Phone No.: (970) 871-6223 Fax No.: (970) 871-6234	2. Company contact for environmental issues: Dr. Ted Guth Phone No.: (619) 670-3157 Fax No.: (619) 670-9454
3. Facility address (if different from above): Spring Canyon Energy, LLC same address, phone and fax Phone no.: ( ) Fax no.: ( )	4. Owners name and address: Same as company name, address, phone, fax Phone no.: ( ) Fax no.: ( )
5. County facility is located in: Juab	6. Latitude & longitude, township & range, and/or UTM coordinates of plant: NAD27 Zone 12 422810 Easting X 4410042 Northing
7. Directions to Installation (street address and/or directions to site) (include U.S. Coast and Geodetic Survey map if necessary): From Salt Lake City: 15 South approximately 77 miles to Hwy 54. Take exit and proceed west through Mona. Go 1/2 mile north on Goshen Canyon Road. Plant site is 1/2 mile to the west	
8. Identify any current Approval Order(s): AO#______ Date______ AO#______ Date______ AO#______ Date______	 AO#______ Date______ AO#______ Date______ AO#______ Date______
9. If request for modification, previous permit # and date: DAQE #______ DATE: __/__/__	
10. Type of business at this facility: Electricity Generation	
11. Total company employees greater than 100? ☐ Yes ☒ No	12. Standard Industrial Classification Code 4 9 1 1

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10231

New Source Review Application
Form 1 (Continued)

13. Application for:
- ☒ New construction
- ☐ Existing equipment operating without permit
- ☐ Change of permit condition
- ☐ Modification
- ☐ Permanent site
- ☐ Change of location

14. For new construction or modification, enter estimated start date: 6-01-02 Estimated completion date: 10-01-03

15. For change of permittee, location or condition, enter date of occurrence: N/A

16. For existing equipment in operation without prior permit, enter initial operation date: N/A

17. Has facility been modified or the capacity increased since November 29, 1969: ☐ Yes ☐ No

Process Information

18. Site plan of facility (Attach as Appendix A):

19. Flow diagram of entire process to include flow rates and other applicable information (Attach as Appendix B):

20. Detailed process/equipment description. (Attach as Appendix C)
Description must include:
Process/Equip specific form(s) identified in the instructions

Fuels and their use	Equipment used in process	Description of product(s)
Raw materials used	Operation schedules	Description of changes to process (if applicable)
Production rates	(including daily/seasonal variances)	

21. Does this application contain confidential data? ☒ Yes ☐ No

Emissions Related Information

22. Describe all potential emissions of air pollutants. (Attach as Appendix D).
Include the following:
- ☒ Emissions for which the source is major.
- ☒ Emissions of regulated and/or hazardous air pollutants.
- ☒ Description of any operational constraints or work practices imposed that limit the amount of regulated or hazardous air pollutants.
- ☒ Emissions above described in terms of lbs/hr, lbs/day, and tons/year.
- ☒ All calculations used to support the emissions data above.
- ☒ All Material Safety Data sheets for products used in process.

23. Identify on the site plan (see #18 above) all emissions points, building dimensions, stack parameters, etc.

Air Pollution Control Equipment Information

24. List all air pollution control equipment and include equipment specific forms identified in the Instructions. Attach as Appendix E.

25. List and describe all compliance monitoring devices and/or activities (such as CEM, pressure gages). Attach as Appendix F.

26. Submit modeling for the project if required. See attached instructions.

27. As part of BACT, Attach as Appendix G an evaluation of the control technologies that have been considered.

28. I hereby certify that the information and data submitted in and with this application is completely true, accurate and complete, based on reasonable inquiry and to the best of my knowledge and belief.

Signature: T Banasiew Title: Managing Member, SpringCanyon Energy, LLC

29.	30 Telephone Number:	30. Date:
Ted Banasiewicz Name (Type or print)	(970) 871-6223	2-11-02

P113

10231

Date Feb. 11, 2002
Company Spring Canyon Energy, LLC
Site Spring Canyon/Mona

Utah Division of Air Quality
New Source Review Section

Form 2
Process Information

Process Data

1. Name of process: Gas-fired electric generation
2. End product of this process: Electricity
3. Primary process equipment: Two (2) gas turbines Manufacturer: General Electric
   Make or model: GE Model PG 7241 FA Identification #: _____
   Capacity of equipment (lbs/hr): combined cycle Year installed: 2002/2003
   Rated 270 MW each Max. 285 MW each
   (Add additional sheets as needed) Gas turbines only: Nominal 170MW each at iso conditions
4. Method of exhaust ventilation:

   ☒ Stack ☐ Window fan ☐ Roof vent ☐ Other, describe _____

   Are there multiple exhausts: ☒ Yes 2 ☐ No

Operating Data

5. Maximum operating schedule: 24 hrs/day; 7 days/week; 52 weeks per yr
6. Percent annual production by quarter:
   Winter 25 Spring 25
   Summer 25 Fall 25
7. Hourly production rates (lbs.): (Total Plant)
   Average 540 MW Maximum 570 MW
8. Maximum Annual production (indicate units)
   4.6 million MW hours
   Projected percent annual increase in production _____
9. Type of operation: ☒ Continuous ☐ Batch ☐ Intermittent
10. If batch, indicate minutes per cycle _____
    Minutes between cycles _____

11. **Materials Used in Process**

Raw Materials	Principal Use	Amounts (Specify Units)
Natural Gas	source of fuel for combustion	4309 MMBTU/hr (HHV)
Water	converted to steam	354 gpm
Air	source of oxygen for combustion	1.4 MMcfm
Ammonia	reactant to reduce NO_x	160 lb/hr

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Process
Form 2 (Continued)

Control Equipment (attach additional pages if necessary)		
Item	Primary Collector	Secondary Collector
a. Type	SCR/CO Catalyst	
b. Manufacturer	Englehardt (or equivalent)	
c. Model	Selective Catalytic Reduction	(NO_x)/CO removal
d. Year installed	2003	
e. Serial or ID#	TBD	
f. Pollutant controlled	NO_x/CO	
g. Controlled pollutant emission rate (if known)	NO_x 2.0 ppmv; CO 5 ppmv	
h. Pressure drop across control device	8"	
i. Design efficiency	NO_x 90.0%	
j. Operating efficiency	NO_x 86.6%	

Stack Data
(attach additional pages if necessary)

13. Stack Identification: GTS 1 GTS 2

14. Height: Above roof NA ft. Above ground 269 ft.

15. Are other sources vented to this stack: ☐ Yes ☒ No

If yes, identify sources:

16. ☒ Round, top inside diameter dimension 19 feet
☐ Rectangular, top inside dimensions length ________ x width ________

17. Exit gas: Temperature 230 °F Volume 744,999 ~~acfm~~ scfm Velocity 4000 ft/min

18. Continuous monitoring equipment: ☒ yes ☐ no
If yes, indicate: Type NO_x, CO, O_2, Manufacturer KVB, Aldora (or equivalent)

Make or Model ________________, Pollutant(s) monitored NO_x, CO, O_2

19. Emission data: Supply maximum annual emission rates (in tons/year) of PM_{10}, SO_2, NO_x, Volatile Organic Compounds, CO, and Hazardous Air Pollutants from source. see attached

Check source of data: ☐ Stack test ☒ Emission factor
☐ Material balance ☒ Manufacturer

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Utah Division of Air Quality
New Source Review Section

Form 22
Combustion Turbines

Date Feb. 11, 2002
Company Spring Canyon Energy, LLC
Facility Spring Canyon/Mona

Equipment Information

1. Manufacturer: General Electric
   Model no : Two (2) Model PG 7241 FA units

2. Operating time of Emission Source:

AVERAGE	MAXIMUM
24 Hours/day	24 Hours/day
7 Days/week	7 Days/week
52 Weeks/year	52 Weeks/year

3. Manufacturer's rated output at baseload, ISO 170 each X☐ MW or ☐ hp
   Proposed site operating range 120-160 each X☐ MW or ☐ hp
   Manufacturer's rated heat rate at baseload, ISO 9480 (BTU/kW-hr) (turbine only)

4. Percent of annual heat input:
   Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %

GAS FIRING

5. Origin of gas:

☒ Pipeline ☐ Distillate fuel oil gasification ☐ Other liquid fuel gasification ☐ Solid fuel gasification ☐ Byproduct: specify source ______

6. Are you on an interruptible gas supply:
   ☐ Yes ☒ No
   If "yes", specify alternate fuel: ______

7. Annual consumption of fuel:
   35,339 MM scf

*8 Heat content: HHV 1011 (natural gas) BTU/scf

*9. Sulfur content: % by wt.

10. Maximum firing rate: 2,170,000**scf/hr (1 unit)
    both units : 4,340,000 scf/hr

11. Average firing rate:
    2,030,00 per unit scf/hr

*If the gas fired is natural gas, these items need not be completed. 4,060,000 scf/hr for the plant

**1.6 MMscf/hr (turbine) plus 0.57 (duct firing) = 2.17MMscf/hr

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Combustion Turbine
Form 22 (Continued)

Oil Firing

Type of oil: N/A

Grade number ☐ 1 ☐ 2 ☐ 4 ☐ 5 ☐ 6 ☐ Other: specify ______

13. Annual consumption: gallons	14. Heat content: ☐ BTU/lb ☐ BTU/gal
15. Sulfur content: % by wt.	16. Ash content % by wt.
17. Direction of firing: ☐ horizontal ☐ tangential ☐ other: specify ______	
18. Average firing rate: gal/hr	19. Maximum firing rate: gal/hr

Operation

20. Application: ☒ Electric generation X Base load ____Peaking ☐ Driving pump/compressor ☒ Exhaust heat recovery ☐ Other (specify) ______	21. Cycle ☐ Simple cycle ☐ Regenerative cycle ☐ Cogeneration ☒ Combined cycle

22. Is turbine equipped with exhaust heat recovery equipment? ☒ Yes ☐ No (for both units)
If yes, supply the size, flow rate, steam output capacity and temperature profile.

1.265 MMlb/hr 188 psi 1000°F high pressure steam; 1.479 MMlb/hr 432 psi 989°F hot reheat steam

23. Is turbine equipped with duct burners? ☒ Yes ☐ No (for both units)
If yes, provide burner description, fuel usage, combustion air input and location of the burners. Show all heat transfer surface locations with the waste heat boiler and temperature profile.
Coen (or equivalent burners); 1,024 MMBTU/hr (HHV) see attached heat balance

Emissions Data

24. Attach manufacturer's information showing emissions of NO_x, CO, VOC, SO_x, and PM_{10} for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM_{10}, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:

☒ Lean premix combustors ☒ Oxidation catalyst ☐ Water Injection ☒ Other (specify)
☐ Other low-NO_x combustor ☒ SCR catalyst ☐ Steam Injection Dry-LoNO$_x$

Additional Information

25. On separate sheets provide the following:
   A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc
   B. Exhaust parameter information on attached form.

Table of Contents

1.0 Introduction

Summary

In an effort to ensure a reliable supply of electrical generation to Utah, Spring Canyon Energy, LLC intends to install natural gas fueled turbine-generators at a new power plant to be located in Spring Canyon near Mona in Juab County. (see Appendix A). The facility will consist of two natural gas fueled gas turbine (GT) engine generator sets operating in a combined cycle configuration with heat recovery steam generators (HRSG's) and a single steam turbine-generator. The HRSG's will each be supplementary fired with natural gas duct burners to augment waste heat from the gas turbine exhaust, which produces steam for powering the steam turbine generator. The Spring Canyon Energy facility will have a nominal generating capacity of 539 MW (net) at 59°F with duct firing and inlet chillers operating.

The gas turbine emissions (corrected to 15% O_2) will be 2.0 ppm NO_x and 5.0 ppm CO (9.0 ppm with duct firing). Annual emissions from the facility are estimated to be no greater than 97.2 tons of NO_x, 240.1 tons of CO, 69.4 tons of fine particulates (PM_{10}), 83.3 tons of volatile organic compounds (VOCs), 8.3 tons SO_2 and 9.5 tons of hazardous air pollutants (HAPs). Modeling of these emissions indicates no violations of the National Ambient Air Quality Standards (NAAQS) as a result of operations. The complete modeling study, performed after approval of the proposed air dispersion modeling protocol, is being submitted to Division of Air Quality with this application. This Notice of Intent (NOI) is being submitted to obtain an approval order for the installation of the two gas turbines at the Spring Canyon site.

Background

The need for the facility is a result of a significant increase in the electrical demand. Additionally, the plant will act as a hedge against high prices for independent operators in the Utah area as well as to provide voltage support. Power generation from natural gas fuel provides the lowest emission option. It is necessary to locate the facility within the Juab Valley near the existing high capacity power lines and high pressure natural gas supply line.

2.0 Process Description

The Spring Canyon facility will consist of two natural gas fueled turbine generator sets. Natural gas (no other fuel will be used) will be introduced with ambient air (chilled when ambient temperatures are above 59°F) into two (2) General Electric Frame 7-FA (PG7241FA) gas turbines to produce approximately 170 MW output, gross, from each turbine generator.

The gas turbines are heavy duty industrial type frame units representing state of the art current day technology. Gas turbine inlet air is compressed and fuel is then introduced and ignited to produce hot exhaust gases that are then expanded through the turbine section of the machine. The rotating turbines in turn drive the generators that produce electricity, the only product delivered by the facility. Waste exhaust heat from the gas turbines is augmented by natural gas fired duct burners and is then directed into heat recovery steam generators to produce steam. This steam is used internally to the plant to drive a steam turbine to create additional "combined cycle" power for export. An air- cooled condenser will condense spent steam back into water for recycling to the HRSG's. Use of the dry type air-cooled condenser greatly reduces the plant's water usage.

It is anticipated that the two gas turbines will be purchased from General Electric. The units are being manufactured in Greenville, South Carolina, and are being configured with the latest technology Dry Lo-NO_x combustion systems and catalysts for Lowest Achievable Emission Rate (LAER) for NO_x, CO and the remaining criteria pollutants. NO_x emissions in the turbine exhaust gas will be controlled to 12-15 ppm by Dry Lo-NO_x prior to passing through the selective catalytic NO_x removal (SCR) system. NO_x emissions will be reduced to 2.0 ppmvd at the stack exit with the SCR catalyst and CO emissions will be 5.0 ppmvd at the stack exit (9.0 ppm for up to 5000 hours per year when turbines augmented with duct firing).

The plant is designed to operate up to 8150 hours per year in base load configuration 24 hours per day, 7 days per week, with only minimal down time for required maintenance. Raw materials used at the Spring Canyon plant in addition to natural gas and air are water (to generate the steam) and ammonia for the selective catalytic (NO_x) reduction process.

The Spring Canyon facility will have a maximum generating capacity of approximately 539 MW at 59°F and is projected to begin operation in September, 2003. Annual emissions from the facility (assuming 8,150 hours of operation per year-including up to 5000 ours per year of duct burner operation) are estimated to be 97 2 tons of NO_x, 240.1 tons of CO, 69.4 tons of fine particulates (PM_{10}), 83.3 tons of volatile organic compounds (VOCs), 8.3 tons of SO_2 and 9.5 tons of hazardous air pollutants (HAPs). All levels are well-below the 250 ton-per-year

PSD threshold. Modeling of the emissions indicates no violations of the National Ambient Air Quality Standards (NAAQS) will result from operation of the plant.

Monitoring of emissions from these units will be performed pursuant to 40 CFR 60.334 (a) and 40 CFR Part 75.

3.0 Emissions Summary

Emissions estimates for NO_x, and CO are based on emissions data provided by equipment manufacturers. SO_2 emissions are based on sulfur content data from Questar. Emissions estimates for VOC's are based on the EPA's *Compilation of Air Pollutant Emission Factors* (AP-42). Ammonia slip from the SCR will be limited to approximately 10 ppmvd, (also based on vendor design data).

The hourly emission rates listed in Table 1 are the maximum rates for operation of the two proposed turbines and duct burners firing natural gas at 100 percent load. The annual emissions from both turbines running with SCR control are also displayed. This assumes a maximum fuel throughput with duct firing of 4034.1 MMBtu/hr (HHV at 59°F) and 8150 hours of annual operation for the turbines.

See Appendix D for detailed emissions model/summary

TABLE 1
Spring Canyon Turbines Emissions Summary with SCR/CO Catalyst Controls[1,2,3]

Pollutant	Annual Emissions (tpy)	Hourly Emissions (lb/hr)	Emission Factor Reference
Criteria Pollutants			
Nitrogen Oxides	97.2	**29.0**	Vendor
Carbon Monoxide	240.1	**7.9**	Vendor
Sulfur Dioxide	8.3	2.26	Questar S data
VOCs (Hydrocarbons)	83.3	**30.2**	5
Particulate Matter[4]	69.4	**22.0**	Vendor
Fine Particulate Mater (PM_{10})	69.4	**22.0**	Vendor
Hazardous Air Pollutants (HAPs)			
1,3 Butadiene	**.035**	.008	5
Acetaldehyde	**.31**	.07	6
Acrolein	**.03**	.007	6
Benzene	.35	.08	6
Ethylbenzene	2.7	.61	5
Formaldehyde	0.91	.207	6
Naphthalene	**.02**	.004	6
PAH	**.004**	.001	6
Propylene Oxide	2.41	.55	5
Toulene	2.24	.51	6
Xylenes	.53	.12	6
	9.54	2.17	

1. The emissions values provided in the tables are the cumulative emissions for both turbines.
2. The hourly emission rates are the maximum rates for operation of the proposed turbines with duct burners firing natural gas at 100 percent loads based on operation at 59°F.
3. Annual emissions are based on operation for 8150 hours per year on natural gas, with up to 5000 hours per year of duct firing.
4. The PM and PM_{10} emissions are EPA Method 5 (front half only).
5. AP-42
6. Ventura County (CA) Air Pollution Control District

Notes:

CO	= Carbon monoxide
hrs/yr	= hours per year
lb/hr	= pounds per hour
NO_x	= Oxides of nitrogen
PM	= Particulate matter
PM_{10}	= Particulate matter less than 10 microns in size
SO_2	= Sulfur dioxide; based on fuel sulfur = 2 gr/1000 cu ft
Tpy	= tons per year
VOC	= Volatile organic compound

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4.0 Regulatory Review

This section provides a regulatory review for the installation of two turbines at the Spring Canyon facility in Utah. The review is divided into two sections. The first section addresses approval order permitting requirements, and the second section addresses other air quality regulatory requirements.

4.a. Air Permit Requirements

Notice of Intent and Approval Order

As required by UAC R307-401, Permit: Notice of Intent and Approval Order, this Notice of Intent application (NOI) is required to be submitted to UDAQ to obtain an approval order (AO) permit prior to installation of the two turbines. Juab County is attainment for all pollutants. As required by R307-401-6, best available control technology (BACT) will be used to control carbon monoxide (CO) emissions. In fact, LAER is being proposed for all remaining criteria pollutants.

New and Modified Sources in Non-attainment Areas and Maintenance Areas

UAC R307-403, Permits: New and Modified Sources in Non-attainment Areas and Maintenance Areas describes the requirements for proposed source permit approval. R307-403-3, Review of Major sources of Air Quality Impact, requires the Executive Secretary to determine if a source will cause or contribute to a violation of the National Ambient Air Quality Standard (NAAQS) as of the source's projected start-up date. The installation of the turbines at the Spring Canyon plant will not cause or contribute to a violation of the NAAQS. The air quality impact analysis demonstrating this is presented in Section 6.

Offsets: General Requirements

The project location is in Juab County, which is an attainment area for all pollutants. Hourly, daily, and annual emission levels are below any and all offset threshold levels. Additionally modeling results show insignificant impact of the project on adjacent non-attainment (for PM_{10}) Utah County. As such, offsets are not required for any pollutant. Thus, provisions of UAC R307-403-4(2), 403-5 and 420 do not apply.

Operating Permit Requirements

The Spring Canyon turbines are required to obtain a Title V Operating Permit. An application for operating permit is required within 12 months of the commencement of operation (UAC R307-415A (B), Permits: Operating Permit Requirements.)

4.b Other Air Quality Regulatory Requirements

New Source Performance Standards

NSPS Subpart GG is applicable to the turbines at Spring Canyon.

Subpart GG- Standards of Performance for Stationary Gas Turbines – Subpart GG of 40 CFR 60 establishes emission limits for NO_x and SO_2 emissions from stationary gas-fired turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 MMBtu/hr), based on the lower heating value of the fuel fired. The turbines at the Spring Canyon facility are subject to this regulation. The higher heating value heat input (fuel flow) of the facility is approximately 4034.1 MMBtu per hour at 59°F at full load when burning natural gas. This is equal to approximately 3181 gigajoules per hour on a lower heating value basis.

Each of the Spring Canyon facility turbines also meets the Subpart GG definition for electric utility stationary gas turbines, since the heat input of each turbine at peak load is greater than 107.2 gigajoules per hour (100 MMBtu/hr). The Spring Canyon turbines are therefore subject to the standards for nitrogen oxides requirements in 40 CFR 60.332. Each turbine is also subject to the SO_2 provisions of 40 CFR 60.333.

The applicable standard limiting the discharge of NO_x into the atmosphere from each of these turbines described in 40 CFR 60.332 is expressed as:

$$STD = 0.0075\,(14.4)/Y + F,$$

Where

STD = allowable NO_x emissions (percent by volume at 5% Oxygen [O_2], and on a dry basis)
Y = manufacturer's rated heat rate in kilojoules per watt hour(kJ/W-hr), not to exceed 14.4
F = fuel-bound nitrogen allowance.

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The heat input rate for each of the Frame 7 turbines is approximately 10 kJ/W-hr at 100% load and 59°F. The resulting NSPS limitation for NO_x is approximately 100 parts per million by volume (ppmvd). The maximum emission rate for each of the turbines of 12 -15 ppmvd before SCR control and 2.0 ppmvd with SCR controls will be well below the NSPS emission limit for NO_x

The SO_2 standard of Subpart GG restricts gaseous discharges form each turbine to a maximum SO_2 content of 0.015% by volume at 15% O_2 and on a dry basis. The SO_2 content of the discharged gases when combusting natural gas will be negligible

40 CFR 60.334 describes monitoring requirements for stationary gas turbines. NO_x, CO and O2 will be the parameters monitored continuously.

This part also contains requirements for monitoring the sulfur and nitrogen content of the fuel being fired in the turbine; 40 CFR 60.334(b) details the frequency with which the fuel must be tested.

Acid Deposition Regulations

The requirements for affected sources under the Acid Rain Program, established pursuant to Title IV of the CAA, are covered under 40 CFR 72 through 78. The turbines at Spring Canyon are subject to these requirements. Specifically this facility will be subject to 40 CFR 72, Permit Regulations, and 40 CFR 75, Continuous Emission Monitoring.

National Emission Standards for Hazardous Air Pollutants for Source Categories

The turbines at Spring Canyon will not emit or have the potential to emit 10 tons/year or greater of any hazardous air pollutant (HAP) or 25 tons/year or greater of any combination of HAPs; therefore, the Spring Canyon facility is not a major source of HAPs. As such, the requirements of 40 CFR part 63 do not apply to the Spring Canyon turbines.

5.0 Control Technology Analyses

In accordance with EPA's "top-down" policy for NO_x, CO and SO_2, this section presents the required best available control technology (BACT) analyses. The section also addresses lowest achievable emission rates (LAER) requirements for PM, PM_{10}, and VOC emissions.

5.a Applicability

UACR R307-401-6 states, "The Executive Secretary shall issue an approval order if he determines through plan review that the following conditions have been met: The degree of pollution control for emissions, to include fugitive emissions and fugitive dust, is at least BACT except as otherwise provided in these regulations".

The following analyses are presented to determine the BACT/LAER controls for each criteria pollutant being emitted for this project.

5.b Top-Down BACT Process

EPA developed a process for conducting BACT analyses, referred to as the "top-down" method. The steps to conducting a top-down analysis were listed in EPA's *New Source Review Workshop Manual*, Draft, October 1990.

Step 1. Identify Potential Control Technologies: The following were conducted: A thorough search of the EPA's RACT/BACT/LAER clearinghouse; Federal/state/local NSR permits; control technology vendors; and environmental consultants.

Step 2 Eliminate Technically Infeasible Options: Technically feasible option means a technology that is available and applicable to the permitee's operations. The analysis is based on chemical, physical and engineering principles or empirical data.

Step 3. Rank Remaining Control Technologies by Control Effectiveness.

Step 4 Evaluate Most Effective Controls and Document Results: The factors considered while evaluating the most effective control options are energy impacts, environmental impacts, and economic impacts

Step 5 Select BACT

Each of these steps has been conducted for CO, and are described below. A LAER analysis of NO_x, SO_2, PM, PM_{10}, and VOC has also been conducted. Note – it is the Spring Canyon project applicant's desire to install LAER for these criteria pollutants.

5.c LAER NO_x Control Analysis

Step 1 – Identify Potential Control Technologies

Potential NO_x control technology options are:

- Selective Catalytic Reduction (SCR) and Dry Lo-NO_x (DLN);
- Xonon
- $SCONO_x$
- DLN only
- SCR only
- Water or Steam Injection

Step 2 - Eliminate Technically Infeasible Options

Conventional SCR requires an exhaust temperature in the 400°F to 800°F range, and when combined with Dry Lo-Nox, achieves 2.0 ppm NO_x. No other technology has achieved this level on gas turbines of this size.

XONON is not available as a control technology for this application. XONON is being developed by Catalytica Combustion Systems, Inc. It is a catalytic combustion system that reduces the production of NO_x. Extensive information on the technology's development indicates that the technology has only been tested on small turbines (less than 10 MW) and is not yet used commercially. This technology has not yet been tested on turbines in the size range of this project's turbines.

Catalytica has entered into an agreement with GE to collaboratively develop the technology for installation on GE Frame E-class and F-class turbines. Catalytica cautions potential investors that adaptation of the technology to GE's turbines will require anywhere from 12 to 24 months. In fact, in a comparison of NO_x control technologies on the website, Catalytica indicates that the technology is "in process" of being proven in practice. XONON cannot be considered an available technology for this project.

Another promising developing technology is $SCONO_x$. $SCONO_x$, like SCR, operates effectively in temperatures ranging from 300°F to 700°F. $SCONO_x$ has not been demonstrated in practice on gas turbines of this scale.

Water injection into the combustion process is an option to reduce NO_x production. Water or steam injection can be utilized to reduce NO_x levels. By injecting water or steam into the flame, flame temperatures are reduced, thereby lowering thermal NO_x formation and overall NO_x levels. Water or steam injection can reduce NO_x levels by up to 80% (when firing natural gas) and can achieve greater reduction when firing oil. There is a practical limit to the amount of water or steam that can be injected into the flame before flame stability problems are experienced. Additionally, under normal operating conditions, water/steam injection can result in 3-10% efficiency loss. Many times water or steam injection is used in conjunction with other NO_x control methods such as burner modifications or flue gas recirculation. Water or steam injection alone can only achieve NO_x levels of 25 ppm.

In summary, for gas turbines of this size, SCR (combined with Dry-Lo-NO_x) is the only viable option to achieve 2.0 ppm NO_x for exhaust temperatures cooled to between 400°F to 850°F. The control effectiveness of any other viable options and possible combinations are presented in Step 3.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

There is only one other proven NO_x reduction control technology combination proven on the large General Electric frame units. A combination of water injection and SCR control can lower emission rates to 5 ppmvd for NO_x. Since the top (minimum NO_x emissions) alternative is proposed for NO_x, no cost, environmental or energy impact analyses are required.

Step 4 – Evaluate Most Effective Controls and Document Results

For combined-cycle operation, LAER is a combination of Dry Lo-NO_x and SCR controls for NO_x.

Step 5 – Select LAER

The final step is to select LAER for the General Electric Frame 7-FA combined cycle operations at Spring Canyon. For the combined cycle GE Frame 7-FA turbine operations, Dry Lo-NO_x and SCR control with a corresponding emission limit of 2.0 ppmvd is proposed as LAER.

5.d BACT Analysis for CO Emissions (see Appendix E)

Step 1 – Identify ~~All~~ Control Technologies

Only two control technologies have been identified for CO control:

1. Combustion Controls
2. CO catalyst

Step 2 – Eliminate Technically Infeasible Options

Both identified control technologies are technically feasible for this project.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

CO catalyst vendors quote guarantee emissions levels of 5.0 ppm. For this project, the turbine vendor has indicated that proper operation of the turbine will result in CO emissions from the combustor of 5.0 ppmvd (corrected to 15% O_2). Thus there is no additional cost to achieve 5.0 ppm CO on these turbines. This level is below that listed in the California Air Resources Board BACT guidance document (6 ppm).

TABLE 5-1
Control Technology Emission Rate Ranking

Control Technology	CO Emissions (ppmv)	Reduction
Combustion Controls	5	NA
CO Catalyst	5	0%

Step 4 – Evaluate Most Effective Controls and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The top-down process requires that the evaluation begin with the most effective technology. The "top" technologies are Combustion Controls or a CO catalyst. Since the top alternative is proposed as BACT for CO, the cost, environmental, and energy impact analyses are not required.

Step 5 – Select BACT

The final step in the top-down BACT analysis process is to select BACT. Good combustion control is proposed as BACT for this project. Good combustion control with CO emissions of 5.0 ppm is proposed as BACT for this project. Note: CO emissions will be kept below 9.0 ppm during the up to 5000 hours per year when the turbines are augmented with duct firing.

5.e LAER Analysis for PM/PM_{10} Emissions

Step 1 – Identify Potential Control Technologies

Three control methods have been identified for PM/PM_{10} control in power generation units:

- Electrostatic precipitators (ESPs)
- Fabric filters
- Combustion of pipeline-quality gas (primary) as the primary fuel

Step 2 – Eliminate Technically Infeasible Options

Neither electrostatic precipitators nor fabric filters are considered to be technically feasible options for combined cycle combustion turbines because of the high exhaust flow rates and the low concentration of particulate in the turbine exhaust.

The particle resistivity associated with gas turbine exhaust is a major problem for ESPs. ESPs remove particles by charging the particles and then collecting them on plates. ESP performance is greatly affected by the ability of the particles to accept and maintain a charge. Because of the resistivity of the exhaust particles from gas turbines, ESPs are not an effective control of turbine particulate matter.

LAER control

The only remaining feasible control method is the use of pipeline-quality natural gas as combustion fuel. This option is PM and PM_{10} LAER for this project

5.f LAER Analysis for SO_2 Emissions

Step 1 – Identify Potential Control Technologies

Four potential control methods have been identified for SO_2 control:

- Wet flue gas desulfurization (FGD) systems;
- Dry FGD systems;
- Spray dryers
- Combustion of pipeline-quality gas as the combustion fuel.

Step 2 - Select LAER

No wet FGD systems, dry FGD systems, nor spray dryers have been applied to the exhaust gases from turbines, and significant technological difficulties are envisioned to apply all of these technologies. The low SO_2 emissions levels inherent with firing natural gas in a turbine constitutes BACT. In a review of the EPA Clearinghouse, the only control methods for SO_2 with turbines were related to the fuel combusted. Each turbine listed in the database was required to fire either pipeline-quality natural gas or a low sulfur fuel oil.

For this application, LAER for SO_2 is the use of pipeline-quality natural gas as the combustion fuel.

5.g LAER Analysis for VOC Emissions

Step 1 – Identify Potential Control Technologies

A review of EPA's Clearinghouse showed LAER control for combined cycle gas turbine combustion units is combustion of pipeline-quality natural gas as the primary fuel.

Select LAER

Use of only pipeline-quality natural gas as the fuel for the turbines is LAER for VOCs for this project.

6.0 Ambient Air Quality Impact Analysis

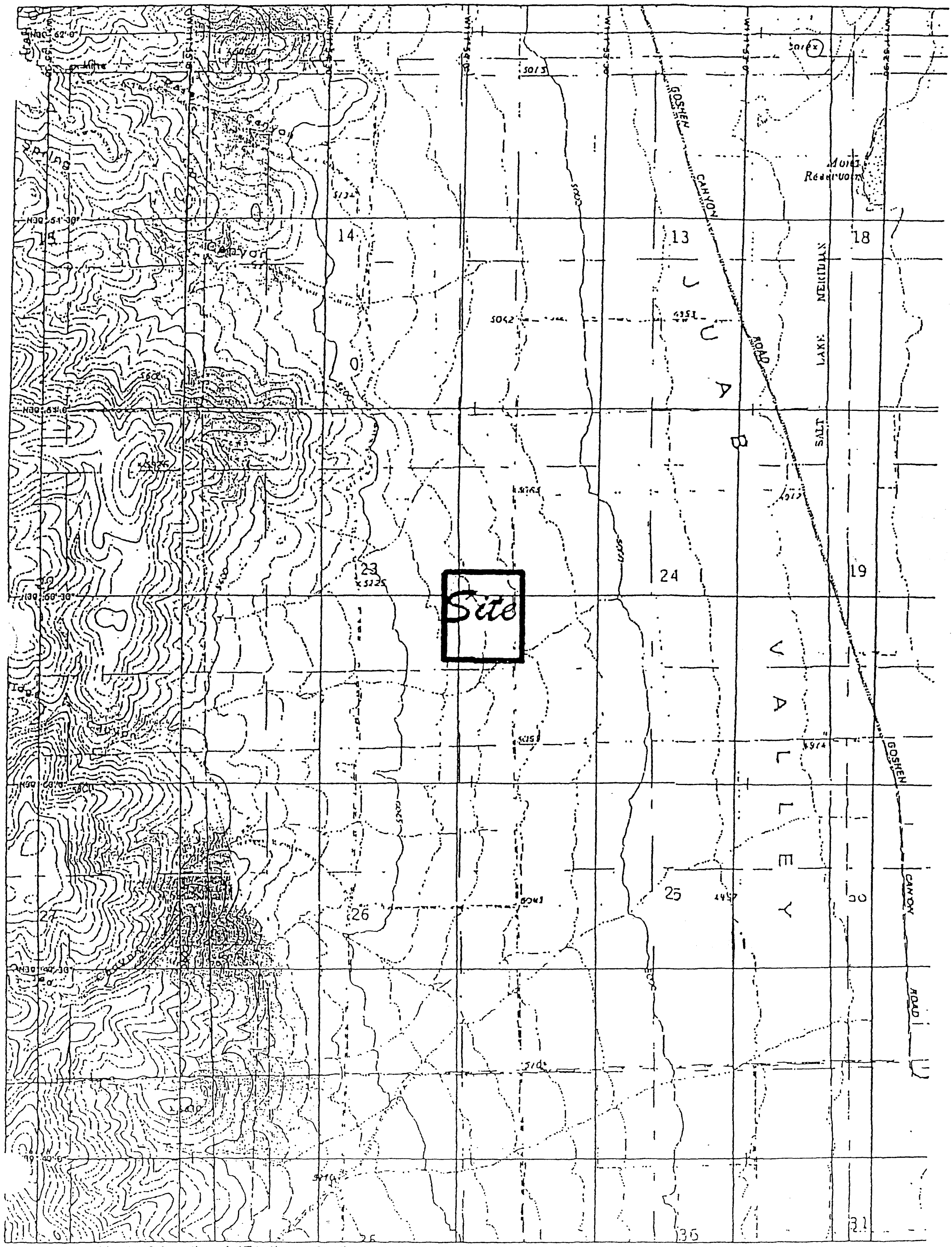
(attached)

7.0 Alternate Siting Analysis

As the Spring Canyon project is located in a county (Juab) in attainment with all national air quality standards, no alternate siting analysis is required.

Appendix A
Site Plan of Facility
(attached)

There are two (2) emission points – identical stacks (269 ft high, 19 feet in diameter). Building dimensions are shown on the Site Plan and the Elevations Drawing.



3-D TopoQuads Copyright © 1999 DeLorme Yarmouth, ME 04096 Source Data: USGS   750 ft Scale: 1 : 25,000 Detail: 13-0 Datum: NAD27

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Appendix B
Flow Diagram
(attached)

Appendix C
Process/Equipment Description

Natural gas (no other fuel will be used) will be introduced with ambient air (chilled when ambient temperatures are above 59°F) into two (2) General Electric Frame 7-FA gas turbines. The gas turbines are oversize versions of the turbines on the wings of aircraft. The gas turbine inlet air is compressed and fuel is then introduced and ignited to produce hot exhaust gases that are expanded through the turbine section of the machine. The rotating turbines in turn drive the generators that produce electricity, the only product delivered by the facility. Waste exhaust heat from the gas turbines is augmented by natural gas fired duct burners and is then directed into heat recovery steam generators to produce steam. This steam is used internally to the plant to drive a steam turbine to create additional "combined cycle" power for export. An air-cooled condenser will condense spent steam back into water for recycling to the HRSG's. Use of the dry type air-cooled condenser greatly reduces the plant's water usage.

Appendix D
Potential Emissions of Air Pollutants

Pollutant	Annual Emissions (tpy)	Hourly Emissions (lb/hr)	Emission Factor Reference
Criteria Pollutants[1,2,3]			
Nitrogen Oxides	97.2	29.0	Vendor
Carbon Monoxide	240.1	79.0	Vendor
Sulfur Dioxide	8.3	2.26	Questar S data
VOCs (Hydrocarbons)	83.3	30.2	5
Particulate Matter[4]	69.4	22.0	Vendor
Fine Particulate Mater (PM_{10})	69.4	22.0	Vendor
Hazardous Air Pollutants (HAPs)			
1,3 Butadiene	.035	.008	5
Acetaldehyde	.31	.07	6
Acrolein	.03	.007	6
Benzene	.35	.08	6
Ethylbenzene	2.7	.61	5
Formaldehyde	0.91	.207	6
Naphthalene	.02	.004	6
PAH	.004	.001	6
Propylene Oxide	2.41	.55	5
Toulene	2.24	.51	6
Xylenes	.53	.12	6
	9.54	2.17	

1. The emissions values provided in the tables are the cumulative emissions for both turbines.
2. The hourly emission rates are the maximum rates for operation of the proposed turbines with duct burners firing natural gas at 100 percent loads based on operation at 59°F.
3. Annual emissions are based on operation for 8150 hours per year on natural gas, with up to 5000 hours per year of duct firing.
4. The PM and PM_{10} emissions are EPA Method 5 (front half only).
5. AP-42
6. Ventura County (CA) Air Pollution Control District

Notes:

CO	= Carbon monoxide
hrs/yr	= hours per year
lb/hr	= pounds per hour
NO_x	= Oxides of nitrogen
PM	= Particulate matter
PM_{10}	= Particulate matter less than 10 microns in size
SO_2	= Sulfur dioxide; based on fuel sulfur = 2 gr/1000 cu ft
Tpy	= tons per year
VOC	= Volatile organic compound

112-01 SPRING CANYON ENERGY, LLC; Utah GE PG7241(FA) DLN 9 Combustor, 5130 Ft Elevation.							
Per GT/DB Hourly Emission Rates		0F	30F	59F	80F	100F	Maximum
Combined GT/DB NOx	#/hr	15 1	14.8	14.5	14.7	14.7	15.1
Combined GT/DB CO	#/hr	41.2	40 6	39.5	40.1	40.1	41.2
Combined GT/DB VOC	#/hr	15 3	15.1	15.1	15.1	15.1	15.3
Combined GT/DB SO2	#/hr	1.2	1.2	1.13	1.1	1.1	1.2
Combined GT/DB Acid Mist	#/hr	0 4	0.4	0.4	0.4	0.4	0.4
Combined GT/DB PM10 (Part + Acid Mist)	#/hr	11 2	11.1	11.0	11.1	11.1	11 2
Per GT/DB Annualized Emission Rates							
Combined GT/DB NOx	Tons/Year	51.2	49.9	48.6	49.2	49.2	51.2
Combined GT/DB CO	Tons/Year	126 9	124.6	120.1	122.4	122.4	126.9
Combined GT/DB VOC	Tons/Year	42 4	41.6	41.6	41.6	41.6	42.4
Combined GT/DB SO2	Tons/Year	4 5	4.3	4.1	4.2	4.2	4.5
Combined GT/DB Acid Mist	Tons/Year	1 6	1.5	1.5	1.5	1.5	1.6
Combined GT/DB PM10 (Part. + Acid Mist)	Tons/Year	35 4	35 2	34.7	35.2	35.2	35.4
Annualized Plant Emission Rates							
Combined GT/DB NOx	Tons/Year	102.4	99.8	97.2	98.5	98.5	102.4
Combined GT/DB CO	Tons/Year	253 9	249.3	240.1	244.7	244.7	253.9
Combined GT/DB VOC	Tons/Year	84 9	83.3	83.3	83.3	83 3	84.9
Combined GT/DB SO2	Tons/Year	8 9	8.6	8.3	8.4	8 4	8.9
Combined GT/DB Acid Mist	Tons/Year	3 2	3.1	2.9	3.0	3.0	3.2
Combined GT/DB PM10 (Part. + Acid Mist)	Tons/Year	70.8	70 5	69.4	70.4	70.4	70.8
Stack Emissions, Dry @ 15% O2 Ref							
NOx	ppmvd	1.93	1.95	1.99	1.98	1.98	2.0
CO	ppmvd	8.63	8.81	8.89	8.88	8.88	8.9
VOC	ppmvd	6.05	6.19	6.45	6.35	6.35	6.5
SO2	ppmvd	0.11	0.11	0.11	0.11	0.11	0.1
Stack Emissions, Lb/mmBTU HHV							
NOx	lb/mmbtu HHV	0 0071	0.0072	0.0073	0.0072	0.0072	0.0073
CO	lb/mmbtu HHV	0.0192	0.0196	0 0198	0.0198	0.0198	0.0198
VOC	lb/mmbtu HHV	0.0077	0.0079	0.0082	0.0081	0.0081	0.0082
SO2	lb/mmbtu HHV	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006
Acid Mist	lb/mmbtu HHV	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
PM10 (Part + Acid Mist)	lb/mmbtu HHV	0.0052	0.0054	0.0056	0.0055	0.0055	0.0056

Base Load + Fired Stack Velocity	Ft/sec	67.93	65.56	60.95	63.17	64.10
Base Load Stack Velocity	Ft/sec	73.72	68 58	63.80	65.61	66.90
75% Load Stack Velocity	Ft/sec	50.57	50 61	50.14	50.23	51.69
50% Load Stack Velocity	Ft/sec	41.15	41.33	40.85	41.24	42.09

Annual GT Operating Hours	hr/yr	8150
Annual DB Operating Hours	hr/yr	5000
No of GT/DB Units		2
Fuel Sulfur	Gr/100 SCF	0.2
Fuel LHV	BTU/SCF	912.1
Fuel HHV	BTU/SCF	1011 4
HHV/LHV ratio		1.109
Duct Burner Firing Rate	mmbtu HHV	520
Stack Diameter	Ft	19
SCR Catalyst Effectiveness		84%
CO Catalyst Effectiveness		

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112-01 SPRING CANYON ENERGY LLC, Utah
GE PG7241(FA) DLN 9 Combustor, 5130 Ft Elevation

Assumptions								
Annual GT Operating Hours	hr/yr	8150						
Annual DB Operating Hours	hr/yr	5000						
Fuel Sulfur	Gr/100 SCF	0.2						
Fuel LHV	BTU/SCF	912.1						
Fuel HHV	BTU/SCF	1011.4						
HHV/LHV ratio		1.109						
Data Inputs		1	2	3	4	5	6	
Ambient Pressure	psia	12.19	12.19	12.19	12.19	12.19	12.19	
Ambient Temperature	F	0	0	0	0	0	0	
Relative Humidity	%	25	25	25	25	25	25	
GT Load	%	100	100	100	100	75	50	
Duct Burner Fuel	mmbtu/hr, HHV	520	364	32.5				
GT NOx	lb/hr	53	53	53	53	40	31	
GT CO	lb/hr	16	16	16	15	11	9	5 ppmvd
GT UHC	lb/hr	13	13	13	13	8	8	
GT Particulates	lb/hr	4	4	4	4	4	4	Guarantee is 9
GT Fuel Consumption	mmBTU/hr, LHV	1462.3	1462.3	1462.3	1462.3	1087.2	878.4	
Duct Burner NOx	lb/mmBTU HHV	0.080	0.080	0.080				
Duct Burner CO	lb/mmBTU HHV	0.050	0.060	0.220				
Duct Burner VOC	lb/mmBTU HHV	0.015	0.035	0.090				
Duct Burner Particulate (PM10)	lb/mmBTU HHV	0.010	0.010	0.010				
GT Exhaust Flow	kpph	3313.0	3313.0	3313.0	3313.0	2382.0	1953.0	
Argon	Vol %	0.90	0.90	0.90	0.90	0.90	0.90	
Nitrogen	Vol %	75.19	75.19	75.19	75.19	75.11	75.2	
Oxygen	Vol %	12.81	12.81	12.81	12.81	12.58	12.86	
Carbon Dioxide	Vol %	3.71	3.71	3.71	3.71	3.69	3.69	
Water	Vol %	7.40	7.40	7.40	7.40	7.51	7.36	
Component Hourly Emission Rates								
GT NOx	lb/hr	53.00	53.00	53.00	53.00	40.00	31.00	
GT CO	lb/hr	15.20	15.20	15.20	15.20	11.26	9.01	
GT VOC	lb/hr	2.60	2.60	2.60	2.60	1.80	1.80	
GT SO2	lb/hr	0.92	0.92	0.92	0.92	0.69	0.55	
GT Acid Mist	lb/hr	0.35	0.35	0.35	0.14	0.11	0.08	
GT PM10 (Part.+ Acid Mist + VOC)	lb/hr	4.74	4.74	4.74	4.53	4.38	4.32	
Duct Burner NOx	lb/hr	41.60	29.12	2.60				
Duct Burner CO	lb/hr	26.00	21.84	7.15				
Duct Burner VOC	lb/hr	7.80	12.74	2.93				
Duct Burner SO2	lb/hr	0.29	0.21	0.02				
Duct Burner Acid Mist	lb/hr	0.07	0.06	0.00				
Duct Burner Particulate (PM10)	lb/hr	5.20	3.64	0.33				
Duct Burner PM10 (Part.+ Acid Mist+VOC)	lb/hr	6.44	5.60	0.77				
Abated Hourly Emission Rates								OF Max
Combined GT/DB NOx	lb/hr	15.14	13.14	8.80	8.48	6.40	4.96	15.1
Combined GT/DB CO	lb/hr	41.20	37.04	22.35	15.20	11.26	9.01	41.2
Combined GT/DB VOC	lb/hr	10.40	15.34	5.53	2.60	1.80	1.60	15.3
Combined GT/DB SO2	lb/hr	1.21	1.12	0.93	0.92	0.69	0.55	1.2
Combined GT/DB Acid Mist	lb/hr	0.42	0.40	0.35	0.14	0.11	0.08	0.4
Combined GT/DB PM10 (Part. + Acid Mist)	lb/hr	11.18	10.34	5.51	4.53	4.38	4.32	11.2
Annualized Emission Rates								
Combined GT/DB NOx	Tons/Year	51.2	46.2	35.6	34.6	26.1	20.2	61.2
Combined GT/DB CO	Tons/Year	128.9	118.5	79.6	61.9	45.9	36.7	128.9
Combined GT/DB VOC	Tons/Year	30.1	42.4	17.9	10.6	7.3	6.5	42.4
Combined GT/DB SO2	Tons/Year	4.5	4.2	3.8	3.7	2.8	2.2	4.5
Combined GT/DB Acid Mist	Tons/Year	1.6	1.5	1.4	0.6	0.4	0.3	1.8
Combined GT/DB PM10 (Part. + Acid Mist)	Tons/Year	35.4	33.3	21.2	18.5	17.8	17.8	36.4
Volumetric Calculations								
GT Exhaust		1	2	3	4	5	6	
GT Exh Mol Wgt, wet		28.468	28.468	28.468	28.468	28.474	28.467	
GT Exh Mol/hr, wet	Mol/hr	116,296	116,296	116,296	116,296	84,008	68,768	
Ar	Mol/hr	1,047	1,047	1,047	1,047	756	619	
N2	Mol/hr	87,443	87,443	87,443	87,443	63,098	51,713	
O2	Mol/hr	14,897	14,897	14,897	14,897	10,568	8,837	
CO2	Mol/hr	4,315	4,315	4,315	4,315	3,201	2,538	
H2O	Mol/hr	8,606	8,606	8,606	8,606	6,393	5,061	
GT Exh Mol/hr, Dry	Mol/hr	107,690	107,690	107,690	107,690	77,615	63,706	
GT Exh O2 Mol%, Dry	Mol %	13.83%	13.83%	13.83%	13.83%	13.62%	13.87%	
Stack Exhaust (GT + Duct Burner)								
Ar	Mol/hr	1,047	1,047	1,047	1,047	756	619	
N2	Mol/hr	87,447	87,446	87,443	87,443	63,098	51,713	
O2	Mol/hr	12,182	12,997	14,728	14,897	10,568	8,837	
CO2	Mol/hr	5,704	5,287	4,401	4,315	3,201	2,538	
H2O	Mol/hr	11,302	10,493	8,774	8,606	6,393	5,061	
Stack Flow, Mol/hr, Wet	Mol/hr	117,682	117,269	116,393	116,307	84,016	68,768	
Stack Flow, Mol/hr, Dry	Mol/hr	106,380	106,776	107,619	107,702	77,623	63,706	
Stack O2 Mol %, Dry	Mol %	11.45%	12.17%	13.69%	13.83%	13.61%	13.87%	
Stack Exhaust Mol Wgt, wet		28.347	28.366	28.478	28.485	28.471	28.467	
Stack Emissions, Wet								OF Max
NOx	ppmvw	2.80	2.44	1.66	1.58	1.68	1.57	2.80
CO	ppmvw	12.50	11.28	6.66	4.67	4.78	4.68	12.50
VOC	ppmvw	5.51	8.15	2.96	1.39	1.34	1.45	8.15
SO2	ppmvw	0.16	0.15	0.13	0.12	0.13	0.12	0.16
Stack Emissions, Dry								
NOx	ppmvd	3.08	2.67	1.80	1.71	1.79	1.69	3.09
CO	ppmvd	13.83	12.38	7.41	6.04	5.18	5.05	13.83
VOC	ppmvd	6.08	8.95	3.20	1.50	1.45	1.57	8.95
SO2	ppmvd	0.18	0.16	0.14	0.13	0.14	0.13	0.18
Stack Emissions, Dry @ 15% O2 Ref								
NOx	ppmvd	1.93	1.81	1.47	1.43	1.45	1.42	1.93
CO	ppmvd	8.63	8.37	6.06	4.21	4.18	4.24	8.63
VOC	ppmvd	3.81	6.05	2.62	1.26	1.17	1.31	6.05
SO2	ppmvd	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Stack Emissions, Lb/mmBTU HHV								
NOx	lb/mmbtu HHV	0.0071	0.0066	0.0054	0.0052	0.0053	0.0051	0.0071
CO	lb/mmbtu HHV	0.0192	0.0187	0.0135	0.0094	0.0083	0.0092	0.0192
VOC	lb/mmbtu HHV	0.0048	0.0077	0.0033	0.0018	0.0015	0.0016	0.0077
SO2	lb/mmbtu HHV	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006
Acid Mist	lb/mmbtu HHV	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001	0.0002
PM10 (Part. + Acid Mist)	lb/mmbtu HHV	0.0052	0.0052	0.0033	0.0028	0.0038	0.0044	0.0052

Min Stack Temperature	F	214	214	214	275	238	234	
Stack Velocity	Ft/sec	67.93	67.83	67.62	73.72	50.57	41.15	
Stack SCFM	SCFM	744,608	741,999	736,456	735,913	531,597	435,113	744,608

EmissionMatrix2
OF
10/30/01

P142

10261

112-01 SPRING CANYON ENERGY LLC, Utah GE PG7241(FA) DLN 9 Combustor, 5130 Ft Elevation									
Assumptions									
Annual GT Operating Hours	hr/yr	8150							
Annual DB Operating Hours	hr/yr	5000							
Fuel Sulfur	Gr/100 SCF	0.2							
Fuel LHV	BTU/SCF	912.1							
Fuel HHV	BTU/SCF	1011.4							
HHV/LHV ratio		1.109							
Data Inputs		1	2	3	4	5	6		
Ambient Pressure	psia	12.19	12.19	12.19	12.19	12.19	12.19		
Ambient Temperature	F	30	30	30	30	30	30		
Relative Humidity	%	28	26	26	25	25	16		
GT Load	%	100	100	100	100	75	50		
Duct Burner Fuel	mmbtu/hr, HHV	520	364	32.5	[redacted]				
GT NOx	lb/hr	51	51	51	51	38	31		
GT CO	lb/hr	15	15	15	15	11	9	5 ppmvd	
GT UHC	lb/hr	12	12	12	12	9	6		
GT Particulates	lb/hr	4	4	4	4	4	4	Guarantee is 9	
GT Fuel Consumption	mmBTU/hr, LHV	1388.5	1388.5	1388.5	1388.6	1048.8	872.3		
Duct Burner NOx	lb/mmBTU HHV	0.080	0.080	0.080	[redacted]				
Duct Burner CO	lb/mmBTU HHV	0.050	0.060	0.220					
Duct Burner VOC	lb/mmBTU HHV	0.015	0.035	0.080					
Duct Burner Particulate (PM10)	lb/mmBTU HHV	0.010	0.010	0.010					
GT Exhaust Flow	kpph	3158.0	3158.0	3158.0	3158.0	2393.0	1867.0		
Argon	Vol %	0.91	0.91	0.91	0.91	0.89	0.89		
Nitrogen	Vol %	75.08	75.08	75.08	75.08	75.03	75.14		
Oxygen	Vol %	12.76	12.76	12.76	12.76	12.62	12.82		
Carbon Dioxide	Vol %	3.72	3.72	3.72	3.72	3.78	3.65		
Water	Vol %	7.64	7.64	7.64	7.64	7.67	7.40		
Component Hourly Emission Rates									
GT NOx	lb/hr	51.00	51.00	51.00	51.00	38.00	31.00		
GT CO	lb/hr	14.84	14.84	14.84	14.84	11.28	9.01		
GT VOC	lb/hr	2.40	2.40	2.40	2.40	1.80	1.80		
GT SO2	lb/hr	0.88	0.88	0.88	0.88	0.68	0.55		
GT Acid Mist	lb/hr	0.34	0.34	0.34	0.13	0.10	0.06		
GT PM10 (Part.+ Acid Mist + VOC)	lb/hr	4.70	4.70	4.70	4.48	4.37	4.32		
Duct Burner NOx	lb/hr	41.60	29.12	2.60	[redacted]				
Duct Burner CO	lb/hr	28.00	21.84	7.15					
Duct Burner VOC	lb/hr	7.80	12.74	2.83					
Duct Burner SO2	lb/hr	0.29	0.21	0.02					
Duct Burner Acid Mist	lb/hr	0.07	0.05	0.00					
Duct Burner Particulate (PM10)	lb/hr	5.20	3.64	0.33					
Duct Burner PM10 (Part.+ Acid Mist+VOC)	lb/hr	6.44	5.60	0.77					
Abated Hourly Emission Rates								30F Max	
Combined GT/DB NOx	lb/hr	14.82	12.62	8.58	8.16	8.24	4.96	14.8	
Combined GT/DB CO	lb/hr	40.84	36.48	21.79	14.84	11.28	9.01	40.8	
Combined GT/DB VOC	lb/hr	10.20	16.14	5.33	2.40	1.80	1.60	16.1	
Combined GT/DB SO2	lb/hr	1.17	1.08	0.88	0.88	0.68	0.55	1.2	
Combined GT/DB Acid Mist	lb/hr	0.40	0.38	0.34	0.13	0.10	0.06	0.4	
Combined GT/DB PM10 (Part. + Acid Mist)	lb/hr	11.13	10.29	5.46	4.49	4.37	4.32	11.1	
Annualized Emission Rates									
Combined GT/DB NOx	Tons/Year	49.8	44.9	34.3	33.3	25.4	20.2	49.8	
Combined GT/DB CO	Tons/Year	124.6	114.2	77.5	59.6	45.9	36.7	124.6	
Combined GT/DB VOC	Tons/Year	29.3	41.6	17.1	9.8	7.3	6.5	41.6	
Combined GT/DB SO2	Tons/Year	4.3	4.1	3.6	3.6	2.8	2.2	4.3	
Combined GT/DB Acid Mist	Tons/Year	1.5	1.5	1.4	0.5	0.4	0.3	1.5	
Combined GT/DB PM10 (Part. + Acid Mist)	Tons/Year	35.2	33.1	21.1	18.3	17.8	17.6	35.2	
Volumetric Calculations									
GT Exhaust		1	2	3	4	5	6		
GT Exh Mol Wgt, wet		28.476	28.475	28.476	28.476	28.462	28.478		
GT Exh Mol/hr, wet	Mol/hr	110,906	110,906	110,906	110,906	84,077	69,070		
Ar	Mol/hr	1,009	1,009	1,009	1,009	748	615		
N2	Mol/hr	83,268	83,268	83,268	83,268	63,083	51,889		
O2	Mol/hr	14,152	14,152	14,152	14,152	10,811	8,924		
CO2	Mol/hr	4,128	4,128	4,128	4,128	3,187	2,521		
H2O	Mol/hr	8,362	8,362	8,362	8,362	6,448	5,111		
GT Exh Mol/hr, Dry	Mol/hr	102,544	102,544	102,544	102,544	77,628	63,959		
GT Exh O2 Mol%, Dry	Mol %	13.80%	13.80%	13.80%	13.80%	13.87%	13.95%		
Stack Exhaust (GT + Duct Burner)									
Ar	Mol/hr	1,009	1,009	1,009	1,009	748	615		
N2	Mol/hr	83,272	83,271	83,268	83,268	63,083	51,889		
O2	Mol/hr	11,436	12,251	13,982	14,152	10,811	8,924		
CO2	Mol/hr	5,515	5,098	4,213	4,128	3,187	2,521		
H2O	Mol/hr	11,058	10,248	8,531	8,362	6,448	5,111		
Stack Flow, Mol/hr, Wet	Mol/hr	112,282	111,878	111,003	110,917	84,077	69,070		
Stack Flow, Mol/hr, Dry	Mol/hr	101,233	101,630	102,472	102,555	77,628	63,959		
Stack O2 Mol %, Dry	Mol %	11.30%	12.05%	13.64%	13.80%	13.67%	13.95%		
Stack Exhaust Mol Wgt, wet		28.328	28.370	28.463	28.472	28.462	28.478		
Stack Emissions, Wet								30F Max	
NOx	ppmvw	2.87	2.48	1.88	1.80	1.81	1.56	2.87	
CO	ppmvw	12.92	11.89	7.01	4.71	4.78	4.66	12.92	
VOC	ppmvw	5.68	8.44	2.99	1.35	1.33	1.44	8.44	
SO2	ppmvw	0.16	0.15	0.13	0.12	0.13	0.12	0.16	
Stack Emissions, Dry									
NOx	ppmvd	3.18	2.74	1.82	1.73	1.75	1.69	3.18	
CO	ppmvd	14.33	12.81	7.60	5.10	5.18	5.03	14.33	
VOC	ppmvd	6.28	9.29	3.24	1.46	1.45	1.56	9.29	
SO2	ppmvd	0.18	0.17	0.14	0.13	0.14	0.13	0.18	
Stack Emissions, Dry @ 15% O2 Ref									
NOx	ppmvd	1.95	1.83	1.48	1.44	1.43	1.43	1.95	
CO	ppmvd	8.81	8.55	6.17	4.23	4.22	4.27	8.81	
VOC	ppmvd	3.86	6.19	2.63	1.21	1.18	1.32	6.19	
SO2	ppmvd	0.11	0.11	0.11	0.11	0.11	0.11	0.11	
Stack Emissions, Lb/mmBTU HHV									
NOx	lb/mmbtu HHV	0.0072	0.0067	0.0054	0.0053	0.0052	0.0051	0.0072	
CO	lb/mmbtu HHV	0.0196	0.0190	0.0138	0.0094	0.0093	0.0093	0.0196	
VOC	lb/mmbtu HHV	0.0049	0.0078	0.0034	0.0015	0.0015	0.0017	0.0078	
SO2	lb/mmbtu HHV	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	
Acid Mist	lb/mmbtu HHV	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001	0.0002	
PM10 (Part. Acid Mist)	lb/mmbtu HHV	0.0054	0.0054	0.0034	0.0028	0.0036	0.0045	0.0054	
Min Stack Temperature	F	222	222	222	257	234	234		
Stack Velocity	Ft/sec	85.58	85.46	85.25	86.58	50.81	41.33		
Stack SCFM	SCFM	710,503	707,895	702,351	701,808	531,982	437,025	710,503	

EmissionMatrix2
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112-01 SPRING CANYON ENERGY LLC, Utah
GE PG7241(FA) DLN 9 Combustor, 6130 Ft Elevation

Assumptions									
Annual GT Operating Hours	hr/yr	8150							
Annual DB Operating Hours	hr/yr	5000							
Fuel Sulfur	Gr/100 SCF	0 2							
Fuel LHV	BTU/SCF	912 1							
Fuel HHV	BTU/SCF	1011 4							
HHV/LHV ratio		1 109							
Data Inputs		1	2	3	4	5	6		
Ambient Pressure	psia	12 19	12.19	12.19	12.19	12.19	12.19		
Ambient Temperature	F	59	59	59	59	59	59		
Relative Humidity	%	45	45	45	45	45	45		
GT Load	%	100	100	100	100	75	50		
Duct Burner Fuel	mmbtu/hr, HHV	520	364	32 5	[redacted]				
GT NOx	#/hr	49	49	49	49	38	31		
GT CO	#/hr	14	14	14	14	11	8		5 ppmvd
GT UHC	#/hr	8 4	12	12	12	9	9		
GT Particulates	#/hr	4	4	4	4	4	4		Guarantee is 9
GT Fuel Consumption	mmBTU/hr, LHV	1331 7	1331 7	1331 7	1331 7	1062.4	867 3		
Duct Burner NOx	#/mmBTU HHV	0 080	0 080	0 080	[redacted]				
Duct Burner CO	#/mmBTU HHV	0.050	0 060	0 220					
Duct Burner VOC	#/mmBTU HHV	0 016	0 035	0.080					
Duct Burner Particulate (PM10)	#/mmBTU HHV	0.010	0 010	0 010					
GT Exhaust Flow	kpph	2868 0	2868 0	2868 0	2868 0	2309 0	1888 0		
Argon	Vol %	0.89	0 89	0 89	0 88	0.90	0.90		
Nitrogen	Vol %	74 61	74.51	74 51	74 51	74 49	74.63		
Oxygen	Vol %	12.59	12.59	12 59	12 59	12.63	12.91		
Carbon Dioxide	Vol %	3.73	3 73	3 73	3.73	3 76	3 64		
Water	Vol %	8 28	8.28	8 28	8 28	8 33	7.99		
Component Hourly Emission Rates									
GT NOx	#/hr	49 00	49 00	49.00	49.00	38.00	31.00		
GT CO	#/hr	13 51	13.51	13.51	13.51	10.70	8 01		
GT VOC	#/hr	1.88	2.40	2.40	2.40	1.80	1 80		
GT SO2	#/hr	0 83	0 83	0.83	0.83	0.68	0 54		
GT Acid Mist	#/hr	0 32	0.32	0.32	0.13	0.10	0 08		
GT PM10 (Part + Acid Mist + VOC)	#/hr	4 57	4 68	4 68	4 49	4 37	4 35		
Duct Burner NOx	#/hr	41.60	29 12	2.60	[redacted]				
Duct Burner CO	#/hr	26 00	21 84	7.16					
Duct Burner VOC	#/hr	7 80	12.74	2.93					
Duct Burner SO2	#/hr	0 29	0.21	0 02					
Duct Burner Acid Mist	#/hr	0.07	0,05	0 00					
Duct Burner Particulate (PM10)	#/hr	5 20	3 64	0 33					
Duct Burner PM10 (Part + Acid Mist+VOC)	#/hr	6 44	5 60	0.77					
Abated Hourly Emission Rates								59F Max	
Combined GT/DB NOx	#/hr	14 50	12.50	8.28	7 84	6.24	4 96	14.6	
Combined GT/DB CO	#/hr	39.51	35.35	20 66	13.51	10 70	8.01	39.5	
Combined GT/DB VOC	#/hr	9 48	16 14	5.33	2.40	1.80	1.80	16.1	
Combined GT/DB SO2	#/hr	1 13	1.04	0 85	0.83	0.68	0.54	1 1	
Combined GT/DB Acid Mist	#/hr	0 39	0.37	0 32	0.13	0.10	0 08	0.4	
Combined GT/DB PM10 (Part + Acid Mist)	#/hr	11,01	10 28	5 45	4.49	4,37	4.35	11 0	
Annualized Emission Rates									
Combined GT/DB NOx	Tons/Year	48 8	43 8	33.0	31.9	25 4	20.2	48 6	
Combined GT/DB CO	Tons/Year	120 1	109 7	72.9	65.1	43.6	34.7	120 1	
Combined GT/DB VOC	Tons/Year	28.3	41 6	17 1	8.8	7 3	7.3	41.6	
Combined GT/DB SO2	Tons/Year	4,1	3.9	3 4	3.4	2.8	2.2	4 1	
Combined GT/DB Acid Mist	Tons/Year	1.5	1,4	1.3	0.5	0 4	0.3	1.5	
Combined GT/DB PM10 (Part + Acid Mist)	Tons/Year	34 7	33 1	21 0	18 3	17 8	17 7	34 7	
Volumetric Calculations									
GT Exhaust		1	2	3	4	5	6		
GT Exh Mol Wgt, wet		28.380	28.380	28.380	28.380	28.382	28.412		
GT Exh Mol/hr, wet	Mol/hr	105,248	105,248	105,248	105,248	84,145	68,971		
Ar	Mol/hr	937	937	937	937	757	630		
N2	Mol/hr	78,420	78,420	78,420	78,420	62,678	52,219		
O2	Mol/hr	13,251	13,251	13,251	13,251	10,543	9,033		
CO2	Mol/hr	3,926	3,926	3,926	3,926	3,164	2,505		
H2O	Mol/hr	8,715	8,715	8,715	8,715	7,009	5,591		
GT Exh Mol/hr, Dry	Mol/hr	96,533	96,533	96,533	96,533	77,135	64,380		
GT Exh O2 Mol%, Dry	Mol %	13.73%	13.73%	13.73%	13.73%	13.67%	14.03%		
Stack Exhaust (GT + Duct Burner)									
Ar	Mol/hr	937	937	937	937	757	630		
N2	Mol/hr	78,424	78,423	78,420	78,420	62,678	52,219		
O2	Mol/hr	10,536	11,350	13,081	13,251	10,543	9,033		
CO2	Mol/hr	5,316	4,899	4,013	3,926	3,164	2,505		
H2O	Mol/hr	11,410	10,602	8,883	8,715	7,009	5,591		
Stack Flow, Mol/hr, Wet	Mol/hr	106,622	106,210	105,334	105,248	84,163	69,978		
Stack Flow, Mol/hr, Dry	Mol/hr	95,212	95,608	96,451	96,533	77,144	64,387		
Stack O2 Mol %, Dry	Mol %	11.07%	11.87%	13.56%	13.73%	13.67%	14.03%		
Stack Exhaust Mol Wgt, wet		28.240	28.284	28.361	28.380	28.369	28.409		
Stack Emissions, Wet								59F Max	
NOx	ppmvw	2.95	2.56	1 70	1 62	1.61	1.54	2.95	
CO	ppmvw	13.23	11 88	7.00	4.56	4.54	4 80	13.23	
VOC	ppmvw	5 54	8 88	3 15	1 42	1.33	1.60	8.88	
SO2	ppmvw	0 17	0.15	0 13	0 12	0,13	0,12	0 17	
Stack Emissions, Dry									
NOx	ppmvd	3 31	2.84	1 88	1 77	1 78	1 67	3.31	
CO	ppmvd	14 82	13.20	7 85	5 00	4 95	4 99	14 82	
VOC	ppmvd	6.21	9 87	3 44	1.55	1,45	1 74	9.87	
SO2	ppmvd	0 19	0 17	0 14	0 13	0 14	0 13	0 19	
Stack Emissions, Dry @ 15% O2 Ref									
NOx	ppmvd	1 99	1 88	1 50	1 46	1,43	1 44	1.99	
CO	ppmvd	8 89	8 63	6 15	4 11	4 04	4.29	8.89	
VOC	ppmvd	3 72	6 45	2.77	1.27	1 19	1.50	6 45	
SO2	ppmvd	0 11	0 11	0 11	0 11	0 11	0 11	0 11	
Stack Emissions, Lb/mmBTU HHV									
NOx	lb/mmbtu HHV	0 0073	0 0068	0 0055	0 0053	0 0052	0 0052	0 0073	
CO	lb/mmbtu HHV	0 0198	0 0182	0 0137	0 0092	0 0089	0 0094	0 0198	
VOC	lb/mmbtu HHV	0 0047	0 0082	0 0035	0 0016	0 0015	0 0019	0.0082	
SO2	lb/mmbtu HHV	0 0006	0,0006	0 0006	0 0006	0 0006	0 0006	0 0006	
Acid Mist	lb/mmbtu HHV	0 0002	0 0002	0 0002	0 0001	0.0001	0 0001	0 0002	
PM10 (Part + Acid Mist)	lb/mmbtu HHV	0 0055	0 0056	0 0036	0 0030	0 0036	0 0045	0 0056	
Min Stack Temperature	F	208	208	208	243	231	217		
Stack Velocity	Ft/sec	60 95	60 65	60 65	63 80	50 14	40 65		
Stack SCFM	SCFM	674,630	672,021	666,478	665,935	532,463	442,770	674,630	

EmissionMaVer2
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112-01 SPRING CANYON ENERGY, LLC, Utah
GE PG7241(FA) DLN 9 Combustor, 6130 Ft Elevation

Assumptions:									
Annual GT Operating Hours	hr/yr	8150							
Annual DB Operating Hours	hr/yr	5000							
Fuel Sulfur	Gr/100 SCF	0.2							
Fuel LHV	BTU/SCF	912.1							
Fuel HHV	BTU/SCF	1011.4							
HHV/LHV ratio		1.109							
		Chiller on							
Data Inputs		1	2	3	4	5	6		
Ambient Pressure	psia	12.19	12.19	12.19	12.19	12.19	12.19		
Ambient Temperature	F	80	80	80	80	80	80		
Relative Humidity	%	40	40	40	40	40	40		
GT Load	%	100	100	100	100	75	50		
Duct Burner Fuel	mmbtu/hr, HHV	520	364	32.5	[redacted]				
GT NOx	#/hr	50	50	50	50	38	31		
GT CO	#/hr	14	14	14	14	11	9		5 ppmvd
GT UHC	#/hr	12	12	12	12	10	8		
GT Particulates	#/hr	4	4	4	4	4	4		Guarantee is 9
GT Fuel Consumption	mmBTU/hr, LHV	1356.0	1356.0	1356.0	1356.0	1084.5	863.8		
Duct Burner NOx	#/mmBTU HHV	0.080	0.080	0.080	[redacted]				
Duct Burner CO	#/mmBTU HHV	0.050	0.060	0.220					
Duct Burner VOC	#/mmBTU HHV	0.015	0.035	0.088					
Duct Burner Particulate (PM10)	#/mmBTU HHV	0.010	0.010	0.010					
GT Exhaust Flow	kpph	3038.0	3038.0	3038.0	3038.0	2411.0	1902.0		
Argon	Vol %	0.90	0.90	0.90	0.90	0.89	0.90		
Nitrogen	Vol %	74.21	74.21	74.21	74.21	73.86	74.1		
Oxygen	Vol %	12.50	12.50	12.50	12.50	12.46	12.87		
Carbon Dioxide	Vol %	3.73	3.73	3.73	3.73	3.72	3.53		
Water	Vol %	8.67	8.67	8.67	8.67	8.98	8.61		
Component Hourly Emission Rates									
GT NOx	#/hr	50.00	50.00	50.00	50.00	38.00	31.00		
GT CO	#/hr	14.08	14.08	14.08	14.08	11.26	9.01		
GT VOC	#/hr	2.40	2.40	2.40	2.40	2.00	1.80		
GT SO2	#/hr	0.85	0.85	0.85	0.85	0.68	0.54		
GT Acid Mist	#/hr	0.32	0.32	0.32	0.13	0.10	0.08		
GT PM10 (Part.+ Acid Mist + VOC)	#/hr	4.68	4.68	4.68	4.40	4.40	4.32		
Duct Burner NOx	#/hr	41.60	29.12	2.60	[redacted]				
Duct Burner CO	#/hr	26.00	21.84	7.15					
Duct Burner VOC	#/hr	7.80	12.74	2.83					
Duct Burner SO2	#/hr	0.29	0.21	0.02					
Duct Burner Acid Mist	#/hr	0.07	0.05	0.00					
Duct Burner Particulate (PM10)	#/hr	5.20	3.64	0.33					
Duct Burner PM10 (Part.+ Acid Mist+VOC)	#/hr	6.44	5.60	0.77					
Abated Hourly Emission Rates								80F Max	
Combined GT/DB NOx	#/hr	14.68	12.66	8.42	8.00	6.24	4.96	14.7	
Combined GT/DB CO	#/hr	40.08	35.92	21.23	14.08	11.26	9.01	40.1	
Combined GT/DB VOC	#/hr	10.20	15.14	5.23	2.40	2.00	1.80	15.1	
Combined GT/DB SO2	#/hr	1.14	1.05	0.87	0.85	0.68	0.54	1.1	
Combined GT/DB Acid Mist	#/hr	0.39	0.37	0.33	0.13	0.10	0.08	0.4	
Combined GT/DB PM10 (Part. + Acid Mist)	#/hr	11.12	10.28	5.45	4.40	4.40	4.32	11.1	
Annualized Emission Rates									
Combined GT/DB NOx	Tons/Year	49.2	44.2	33.6	32.8	25.4	20.2	49.2	
Combined GT/DB CO	Tons/Year	122.4	112.0	75.2	57.4	45.9	36.7	122.4	
Combined GT/DB VOC	Tons/Year	28.3	41.6	17.1	9.8	8.2	6.5	41.6	
Combined GT/DB SO2	Tons/Year	4.2	4.0	3.5	3.5	2.8	2.2	4.2	
Combined GT/DB Acid Mist	Tons/Year	1.5	1.4	1.3	0.5	0.4	0.3	1.6	
Combined GT/DB PM10 (Part. + Acid Mist)	Tons/Year	35.2	33.1	21.0	18.3	17.9	17.6	35.2	
		Volumetric Calculations							
GT Exhaust		1	2	3	4	5	6		
GT Exh Mol Wgt, wet		28.352	28.352	28.352	28.352	28.316	28.340		
GT Exh Mol/hr, wet	Mol/hr	107,155	107,155	107,155	107,156	85,146	70,641		
Ar	Mol/hr	964	964	964	964	758	636		
N2	Mol/hr	79,519	79,519	79,519	79,519	62,974	52,345		
O2	Mol/hr	13,384	13,384	13,384	13,384	10,609	9,092		
CO2	Mol/hr	3,997	3,997	3,997	3,997	3,167	2,494		
H2O	Mol/hr	9,290	9,290	9,290	9,290	7,646	6,082		
GT Exh Mol/hr, Dry	Mol/hr	97,864	97,864	97,864	97,864	77,500	64,559		
GT Exh O2 Mol%, Dry	Mol %	13.68%	13.68%	13.68%	13.68%	13.80%	14.08%		
Stack Exhaust (GT + Duct Burner)									
Ar	Mol/hr	964	964	964	964	758	636		
N2	Mol/hr	79,523	79,522	79,520	79,519	62,974	52,345		
O2	Mol/hr	10,879	11,494	13,225	13,384	10,609	9,092		
CO2	Mol/hr	5,367	4,970	4,084	3,997	3,167	2,494		
H2O	Mol/hr	11,986	11,177	9,459	9,290	7,646	6,082		
Stack Flow, Mol/hr, Wet	Mol/hr	108,639	108,127	107,251	107,165	85,154	70,648		
Stack Flow, Mol/hr, Dry	Mol/hr	96,553	96,950	97,792	97,875	77,508	64,566		
Stack O2 Mol %, Dry	Mol %	11.06%	11.86%	13.52%	13.68%	13.80%	14.08%		
Stack Exhaust Mol Wgt, wet		28.201	28.245	28.339	28.349	28.313	28.337		
Stack Emissions, Wet								80F Max	
NOx	ppmvw	2.93	2.54	1.71	1.62	1.59	1.53	2.93	
CO	ppmvw	13.18	11.86	7.07	4.89	4.72	4.65	13.18	
VOC	ppmvw	5.66	8.73	3.09	1.40	1.46	1.41	8.73	
SO2	ppmvw	0.16	0.15	0.13	0.12	0.12	0.12	0.16	
Stack Emissions, Dry									
NOx	ppmvd	3.30	2.84	1.87	1.78	1.75	1.67	3.30	
CO	ppmvd	14.82	13.23	7.75	5.13	5.19	4.98	14.82	
VOC	ppmvd	6.54	9.73	3.38	1.53	1.61	1.54	9.73	
SO2	ppmvd	0.18	0.17	0.14	0.14	0.14	0.13	0.18	
Stack Emissions, Dry @ 15% O2 Ref									
NOx	ppmvd	1.98	1.85	1.50	1.45	1.43	1.44	1.98	
CO	ppmvd	8.88	8.63	6.20	4.20	4.24	4.31	8.88	
VOC	ppmvd	3.95	6.35	2.71	1.25	1.32	1.34	6.35	
SO2	ppmvd	0.11	0.11	0.11	0.11	0.11	0.11	0.11	
Stack Emissions, Lb/mmBTU HHV									
NOx	lb/mmbtu HHV	0.0072	0.0068	0.0055	0.0053	0.0052	0.0052	0.0072	
CO	lb/mmbtu HHV	0.0198	0.0192	0.0138	0.0084	0.0084	0.0084	0.0198	
VOC	lb/mmbtu HHV	0.0050	0.0081	0.0035	0.0018	0.0017	0.0017	0.0081	
SO2	lb/mmbtu HHV	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	
Acid Mist	lb/mmbtu HHV	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001	0.0002	
PM10 (Part. + Acid Mist)	lb/mmbtu HHV	0.0055	0.0055	0.0035	0.0030	0.0037	0.0045	0.0055	

Min Stack Temperature	F	220	220	220	260	224	217	
Stack Velocity	Ft/sec	63.17	63.07	62.88	65.61	50.23	41.24	
Stack SCFM	SCFM	686,763	684,154	678,811	678,067	538,796	447,014	686,763

112-01 SPRING CANYON ENERGY, LLC; Utah
GE PG7241(FA) DLN-9 Combustor, 5130 Ft Elevation.

Assumptions:									
Annual GT Operating Hours	hr/yr	8150							
Annual DB Operating Hours	hr/yr	5000							
Fuel Sulfur	Gr/100 SCF	0.2							
Fuel LHV	BTU/SCF	912.1							
Fuel HHV	BTU/SCF	1011.4							
HHV/LHV ratio		1.109							
		Chiller on							
Data Inputs		1	2	3	4	5	6		
Ambient Pressure	psia	12.19	12.19	12.19	12.19	12.19	12.19		
Ambient Temperature	F	100	100	100	100	100	100		
Relative Humidity	%	10	10	10	10	10	10		
GT Load	%	100	100	100	100	75	50		
Duct Burner Fuel	mmbtu/hr, HHV	520	364	32.5	[redacted]	[redacted]	[redacted]		
GT NOx	#/hr	50	50	50	50	39	31		
GT CO	#/hr	14	14	14	14	11	10		5 ppmvd
GT UHC	#/hr	12	12	12	12	10	8		
GT Particulates	#/hr	4	4	4	4	4	4		Guarantee is 9
GT Fuel Consumption	mmBTU/hr, LHV	1366.0	1354.0	1366.0	1356.0	1084.8	857.5		
Duct Burner NOx	#/mmBTU HHV	0.080	0.080	0.080	[redacted]	[redacted]	[redacted]		
Duct Burner CO	#/mmBTU HHV	0.050	0.060	0.220	[redacted]	[redacted]	[redacted]		
Duct Burner VOC	#/mmBTU HHV	0.015	0.035	0.080	[redacted]	[redacted]	[redacted]		
Duct Burner Particulate (PM10)	#/mmBTU HHV	0.010	0.010	0.010	[redacted]	[redacted]	[redacted]		
GT Exhaust Flow	kpph	3038.0	3038.0	3038.0	3038.0	2454.0	2026.0		
Argon	Vol %	0.90	0.90	0.90	0.90	0.90	0.89		
Nitrogen	Vol %	74.21	74.21	74.21	74.21	74.66	74.81		
Oxygen	Vol %	12.50	12.50	12.50	12.50	12.75	13.16		
Carbon Dioxide	Vol %	3.73	3.73	3.73	3.73	3.67	3.48		
Water	Vol %	8.67	8.67	8.67	8.67	8.03	7.66		
Component Hourly Emission Rates									
GT NOx	#/hr	50.00	50.00	50.00	50.00	39.00	31.00		
GT CO	#/hr	14.08	14.08	14.08	14.08	11.28	9.57		
GT VOC	#/hr	2.40	2.40	2.40	2.40	2.00	1.60		
GT SO2	#/hr	0.85	0.85	0.85	0.85	0.68	0.54		
GT Acid Mist	#/hr	0.32	0.32	0.32	0.13	0.10	0.08		
GT PM10 (Part. + Acid Mist + VOC)	#/hr	4.68	4.68	4.68	4.49	4.40	4.32		
Duct Burner NOx	#/hr	41.60	29.12	2.60	[redacted]	[redacted]	[redacted]		
Duct Burner CO	#/hr	26.00	21.84	7.16	[redacted]	[redacted]	[redacted]		
Duct Burner VOC	#/hr	7.80	12.74	2.93	[redacted]	[redacted]	[redacted]		
Duct Burner SO2	#/hr	0.29	0.21	0.02	[redacted]	[redacted]	[redacted]		
Duct Burner Acid Mist	#/hr	0.07	0.05	0.00	[redacted]	[redacted]	[redacted]		
Duct Burner Particulate (PM10)	#/hr	5.20	3.64	0.33	[redacted]	[redacted]	[redacted]		
Duct Burner PM10 (Part.+ Acid Mist+VOC)	#/hr	8.44	6.60	0.77	[redacted]	[redacted]	[redacted]		
Abated Hourly Emission Rates								100F Max	
Combined GT/DB NOx	#/hr	14.68	12.68	8.42	8.00	6.24	4.96	14.7	
Combined GT/DB CO	#/hr	40.08	35.92	21.23	14.08	11.28	9.57	40.1	
Combined GT/DB VOC	#/hr	10.20	15.14	5.33	2.40	2.00	1.60	15.1	
Combined GT/DB SO2	#/hr	1.14	1.05	0.87	0.85	0.68	0.54	1.1	
Combined GT/DB Acid Mist	#/hr	0.39	0.37	0.33	0.13	0.10	0.08	0.4	
Combined GT/DB PM10 (Part. + Acid Mist)	#/hr	11.12	10.28	5.45	4.49	4.40	4.32	11.1	
Annualized Emission Rates									
Combined GT/DB NOx	Tons/Year	49.2	44.2	33.8	32.6	25.4	20.2	49.2	
Combined GT/DB CO	Tons/Year	122.4	112.0	75.2	57.4	45.9	39.0	122.4	
Combined GT/DB VOC	Tons/Year	29.3	41.6	17.1	9.8	8.2	6.5	41.6	
Combined GT/DB SO2	Tons/Year	4.2	4.0	3.5	3.5	2.8	2.2	4.2	
Combined GT/DB Acid Mist	Tons/Year	1.5	1.4	1.3	0.5	0.4	0.3	1.5	
Combined GT/DB PM10 (Part. + Acid Mist)	Tons/Year	35.2	33.1	21.0	18.3	17.9	17.6	35.2	
		Volumetric Calculations							
GT Exhaust		1	2	3	4	5	6		
GT Exh Mol Wgt, wet		28.352	28.352	28.352	28.352	28.416	28.435		
GT Exh Mol/hr, wet	Mol/hr	107,155	107,155	107,155	107,155	86,360	71,251		
Ar	Mol/hr	964	964	964	964	777	634		
N2	Mol/hr	79,519	79,519	79,519	79,519	64,478	53,303		
O2	Mol/hr	13,394	13,394	13,394	13,394	11,011	9,377		
CO2	Mol/hr	3,997	3,997	3,997	3,997	3,169	2,480		
H2O	Mol/hr	9,290	9,290	9,290	9,290	6,935	5,458		
GT Exh Mol/hr, Dry	Mol/hr	97,864	97,864	97,864	97,864	79,425	65,793		
GT Exh O2 Mol%, Dry	Mol %	13.69%	13.69%	13.69%	13.69%	13.86%	14.25%		
Stack Exhaust (GT + Duct Burner)									
Ar	Mol/hr	964	964	964	964	777	634		
N2	Mol/hr	79,523	79,522	79,520	79,519	64,478	53,303		
O2	Mol/hr	10,679	11,494	13,225	13,394	11,011	9,377		
CO2	Mol/hr	5,387	4,970	4,084	3,997	3,169	2,480		
H2O	Mol/hr	11,986	11,177	9,458	9,290	6,935	5,458		
Stack Flow, Mol/hr, Wet	Mol/hr	108,539	108,127	107,251	107,165	86,369	71,251		
Stack Flow, Mol/hr, Dry	Mol/hr	96,553	96,950	97,792	97,875	79,434	65,793		
Stack O2 Mol %, Dry	Mol %	11.06%	11.86%	13.52%	13.69%	13.86%	14.25%		
Stack Exhaust Mol Wgt, wet		28.201	28.245	28.339	28.349	28.413	28.435		
Stack Emissions, Wet								100F Max	
NOx	ppmvw	2.93	2.54	1.71	1.62	1.57	1.51	2.93	
CO	ppmvw	13.18	11.86	7.07	4.69	4.65	4.80	13.18	
VOC	ppmvw	5.86	8.73	3.09	1.40	1.44	1.40	8.73	
SO2	ppmvw	0.16	0.15	0.13	0.12	0.12	0.12	0.16	
Stack Emissions, Dry									
NOx	ppmvd	3.30	2.84	1.87	1.76	1.71	1.64	3.30	
CO	ppmvd	14.82	13.23	7.76	5.13	6.06	5.19	14.82	
VOC	ppmvd	6.59	9.73	3.39	1.53	1.57	1.52	9.73	
SO2	ppmvd	0.18	0.17	0.14	0.14	0.13	0.13	0.18	
Stack Emissions, Dry @ 15% O2 Ref									
NOx	ppmvd	1.98	1.85	1.50	1.45	1.43	1.45	1.98	
CO	ppmvd	8.88	8.63	6.20	4.20	4.24	4.61	8.89	
VOC	ppmvd	3.95	6.35	2.71	1.25	1.32	1.35	6.35	
SO2	ppmvd	0.11	0.11	0.11	0.11	0.11	0.11	0.11	
Stack Emissions, Lb/mmBTU HHV									
NOx	lb/mmbtu HHV	0.0072	0.0068	0.0055	0.0053	0.0052	0.0052	0.0072	
CO	lb/mmbtu HHV	0.0198	0.0192	0.0138	0.0094	0.0094	0.0101	0.0198	
VOC	lb/mmbtu HHV	0.0050	0.0081	0.0035	0.0016	0.0017	0.0017	0.0081	
SO2	lb/mmbtu HHV	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006	
Acid Mist	lb/mmbtu HHV	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001	0.0002	
PM10 (Part. + Acid Mist)	lb/mmbtu HHV	0.0055	0.0055	0.0035	0.0030	0.0037	0.0045	0.0055	

Min Stack Temperature	F	230	150	230	264	234	225	
Stack Velocity	Ft/sec	64.10	64.00	63.78	65.90	51.69	42.09	
Stack SCFM	SCFM	686,763	684,154	678,611	678,067	546,481	450,824	686,763

EmissionMatrix2
100F
10/30/01

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Appendix E
Air Pollution Control Equipment

Air pollution control equipment for this project includes:

Combustion Control for CO
Dry Lo-NO_x Combustor
Selective Catalytic Reduction (SCR) Catalyst (NO_x)

Note: Natural Gas is the only fuel proposed for use at the Spring Canyon Energy plant. Natural gas is LAER for PM-10, VOC and SO_2 control.
Maximum stack exhaust flow is 744, 999 ACFM @230°F at low ambient temperature conditions.

Support for Elimination of Oxidation Catalyst Requirements for General Electric Co. (GE) PG7241FA DLN Combustion Turbines

Brahim Richani, Ph.D., Manager, Environmental Engineering, GE Power Systems
Joel Chalfin, GT/CC Environmental Compliance Manager, GE Power Systems

Applicability

This position paper applies to GE PG7241FA combustion turbines with DLN combustors firing natural gas and located in all attainment areas and ozone non-attainment areas. For all other GE heavy-duty frame machines, owners are advised to contact their GE Power Generation sales representative for information regarding oxidation catalysts and related requirements.

Abstract

Regulated emissions requirements have become more stringent for combustion turbines (CTs), generally requiring installation of post combustion controls regardless of uncontrolled emission levels, plant location, costs, process feasibility, or resulting environmental impacts. Federal and state regulatory agencies have sought to justify post-combustion controls primarily on the grounds that some existing installations are currently using oxidation catalysts for carbon monoxide (CO) control. However, a "one-size-fits-all" approach, where all units are required to install a particular technology without consideration of individualized factors, is in direct conflict with the Clean Air Act (CAA) Best Available Control Technology (BACT) analysis procedures and requirements.

The BACT analysis for CO (or any criteria pollutant) must weigh a variety of factors including energy, environmental and economic impacts. Dry Low NOx (DLN) combustors for GE PG7241FA combustion turbines are now demonstrating uncontrolled CO emissions in a range so low that the requirement to add an oxidation catalyst on these units will only serve to reduce efficiency and output; produce negative environmental impacts; and, in light of the measured data, will not yield detectable CO emissions reduction benefits under normal operating conditions.

As mentioned above, the comparison to existing installations with CO catalysts is apparently the primary factor influencing regulatory agencies to insist on the installation of oxidation catalysts on all combustion turbine units. However, two additional factors are also considered in this paper; the impetus for expedited permitting, and the anticipated federal regulation for hazardous air pollutant (HAP) emissions from combustion turbines.

The objective of this paper is to demonstrate that the installation of an oxidation catalyst to achieve lower CO levels from GE PG7241FA DLN combustion turbines sited in attainment areas and ozone non-attainment areas should not be required by state, local, and/or federal regulatory agencies. The addition of oxidation catalysts to these units results in minimal CO emissions reduction, adds costs, and produces negative environmental impacts.

1.0 Introduction

State and federal regulatory agencies are requiring oxidation catalysts as BACT for CO emissions on combustion turbines in an attempt to achieve lower CO emissions. Such requirements are making it difficult for site owners and combustion turbine manufacturers to avoid the installation of oxidation catalysts as add-on controls, regardless of the uncontrolled CO emissions levels The statutorily mandated BACT process is being circumvented and U.S.

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EPA's own BACT guidance is being ignored. *The Clean Air Act (CAA)* clearly requires that a BACT determination be conducted on a "case-by-case" basis; however it appears that in many cases the regulatory agencies are influencing applicants' control technology choices and their BACT determination based on the following factors:

- Existing installations of various manufacturers' units that are using CO catalysts (i.e., "presumptive BACT");
- Applicants demands for an expedited permitting process; and
- Currently non-existent, but anticipated, Maximum Achievable Control Technology (MACT) Requirements.

Consequently, the regulatory agencies appear to be excluding other important factors in their BACT determinations, such as:

- Cost effectiveness and feasibility of control,
- Evaluation of collateral environmental impacts, and
- Evaluation of expected CO emissions on public health.

GE PG7241FA DLN natural gas-fired combustion turbines have consistently demonstrated uncontrolled CO emissions below 9 parts per million by volume dry (ppmvd) at base load. A requirement to add an oxidation catalyst to a GE PG7241FA DLN combustion turbine with single digit CO emissions will reduce efficiency and output, and produce negative environmental consequences while yielding non-detectable reduction in CO emissions under normal operating conditions. For areas designated as attainment for carbon monoxide, it becomes critical that the BACT analysis for CO includes environmental, cost effectiveness, and potential health impacts. The following provides an explanation of why BACT determinations for CO emissions for GE's PG7241FA DLN units should result in a conclusion of "No Add-on Controls."

2.0 EXISTING INSTALLATIONS

A review of existing CT installations located in attainment areas which are using oxidation catalysts, indicates that uncontrolled CO emission levels from these units are much higher than the demonstrated emission levels from GE's PG7241FA DLN combustion turbines. The existing installations reviewed have uncontrolled CO emission rates in the range of 15 to 25 ppmvd, while GE's PG7241FA DLN's have demonstrated uncontrolled CO levels of much less than 9 ppmvd. As a result, the cost effectiveness of an oxidation catalyst for installations other than the GE PG7241FA DLN combustion turbine is more reasonable, since greater CO emissions reductions are achieved from the higher emitting units. When post combustion control, such as an oxidation catalyst, is added to the higher emitting units, the resulting CO level achieved and permitted is approximately 5 ppmvd. This emission rate is achieved by the GE PG7241FA DLN units, ***without any add-on controls.***

In ozone non-attainment areas, an additional consideration is VOC emissions. Oxidation catalysts can be used to reduce VOC emissions from CTs. However, GE PG7241 DLN units produce no measurable quantities of VOC emissions, and an oxidation catalyst for the reduction of VOCs serves no purpose and produces no benefits.

Given this fact, it seems clear that recent EPA BACT decisions requiring add-on controls for CO emissions for GE PG7241 FA DLN units have failed to undertake a case-by-case BACT analysis as required by the CAA. In addition, the EPA's determination has, in many cases, excluded the results of cost effectiveness analyses and collateral environmental impacts.

3.0 EXPEDITED PERMITTING PROCESS

The current demand to increase electric power supply availability in the U.S. is at an all-time high. Some states are experiencing rotating power blackouts (e g, CA) and others (e g, NY) are expected to follow suit because of the increased energy demand and the limited number of new power plants which have been permitted and built in the deregulated market. As a result of the need for immediate energy supplies, limited or no BACT analyses are conducted for many projects because the applicants have included all available controls (SCR and oxidation catalyst) and yielded to regulatory pressures to expedite the permitting process. The result is that BACT has essentially become an automatic requirement of an oxidation catalyst for CO emissions reduction for future projects.

4.0 Up-Coming MACT Requirements for HAPs

Some state and local regulatory agencies are using the soon to be issued U.S. EPA Maximum Achievable Control Technology (MACT) standard intended for the reduction of hazardous air pollutants (Primarily formaldehyde) emission levels from combustion turbines as the basis for requiring oxidation catalysts. As of August 2001, when this position paper was drafted, the MACT rule for combustion turbines had not yet been proposed. However, EPA has provided some information on what the rule would require through correspondence detailing the meeting minutes between the EPA and PRCI dated April 4, 2001. According to the EPA's minutes, all new combustion turbines will likely be required to install an oxidation catalyst to reduce hazardous air pollutants (HAPs), unless a formaldehyde emission level of less than 25 parts per billion by volume, dry (ppbvd) corrected to 15% O2 is achieved. For combustion turbines achieving less than 25 ppbvd @15% O_2 of formaldehyde, the MACT requirement is expected to be "No Additional Control."

On August 21, 2001, EPA issued a memorandum indicating, "HAP emissions from lean premix stationary combustion turbines are equivalent or lower than HAP emissions from diffusion flame stationary combustion turbines equipped with oxidation catalyst systems. Thus, lean premix combustion is a comparable technology to oxidation catalyst systems."

Additionally, GE has tested and provided EPA with formaldehyde emissions data using CARB Method 430 from two PG7241FA DLN natural gas-fired turbines. The test results demonstrate that the uncontrolled formaldehyde emissions when blank corrected are typically below 25 ppbvd @ 15% O2. Therefore, based on the blank corrected measurements, GE's PG7241FA DLN units may not be subject to the up-coming MACT regulation and an oxidation catalyst would not be justified for MACT compliance.

5.0 Cost Effectiveness

Inconsistent implementation of BACT across regions will occur if cost of control and the resulting cost-effectiveness levels are not evaluated. As indicated in Table 1, dollars per ton cost effectiveness analyses as low as $2,055 per ton (Newington Energy in New Hampshire) have resulted in a decision that no oxidation catalyst is required for CO from gas combustors with emissions of 15 ppmvd. These figures conflict directly with a recent decision by EPA Region II that $6,000/ton and less is considered cost effective for CO control in attainment areas. The lack of uniform EPA guidance regarding cost effectiveness determinations is causing inconsistencies in BACT determinations across the country.

GE's data collected to date on PG7241FA combustion turbines, shown in Figure 1, indicate CO levels below 2 ppmvd at various loads. These data suggest that the addition of oxidation catalysts to GE's PG7241FA DLN units will not result in any appreciable CO reductions, and that the cost effectiveness of such controls will be low (i.e., very high cost per ton controlled).

To demonstrate that GE's PG7241FA DLN units should not require add-on controls for BACT determinations, cost effectiveness calculations are presented in Figure 2.

TABLE 1 – COST EFFECTIVENESS LEVELS FOR RECENTLY PERMITTED SITES

Source/State	Model	Type of Operation	Catalytic Oxidation System Required	Cost Eff. ($/ton)	Final CO BACT based on Natural Gas	Issuance
Westbrook Pwr/ME	PG7241FA	Combined Cycle	No	>$3,000	15 ppmv	Draft findings of Fact and Order (12/98)
Newington Energy/NH	PG7241FA	Combined Cycle	No	$2,055	15 ppmv	4/99
EMI Tiverton/RI	PG7241FA	Combined Cycle	No	$7,400	12 ppmv	2/98
RockGen Energy/ WI	PG7241FA	Simple Cycle	No	$15,780	12 ppmv	1/99
SEI/WI	PG7241FA	Simple Cycle	No	$14,000	12 ppmv	2/99
Tenaska Georgia Ptnrs/GA	PG7241FA	Simple Cycle	No	$2,300	15 ppmv	12/98
PeopleGas and Light, McDonnell Energy/IL	PG7241FA	Combined and Simple Cycle	No	$3,043 $17,000	0 03 lb/mmBtu	1/99

FIGURE 1 - Average Raw CO Emissions vs. Load Size

GE PG7241FA CT Units

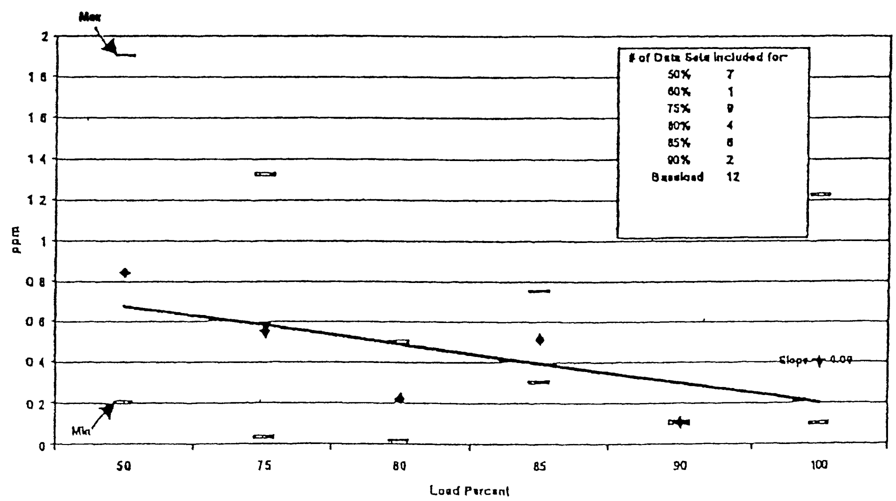

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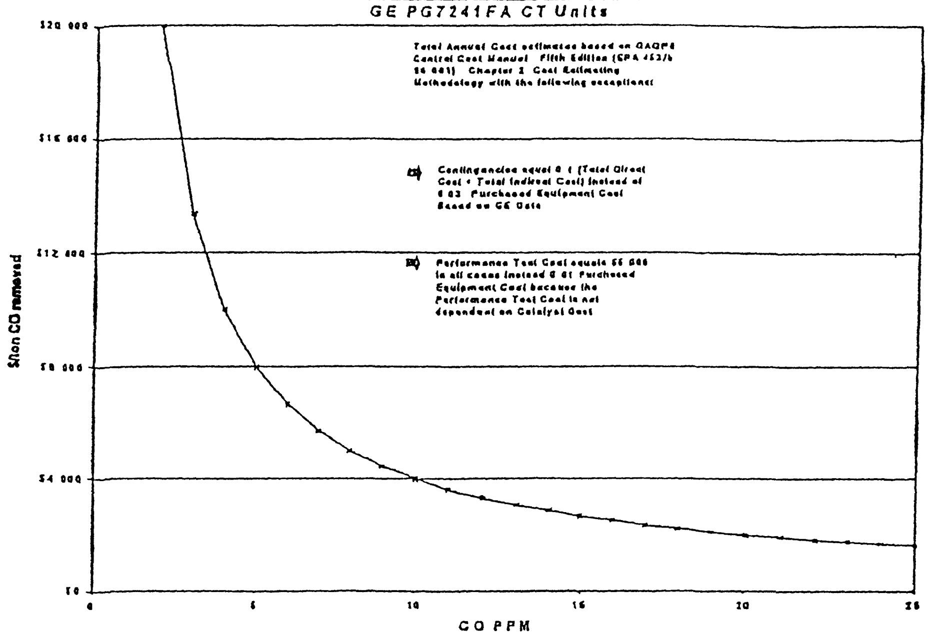
FIGURE 2 - Cost Effectiveness of Oxidation Catalysts
$/Ton CO Removed vs. PPM
GE PG7241FA CT Units



These cost estimates are based on recently (1st Quarter, 2001) gathered information from two leading catalyst manufacturers (Englehard & Johnson Matthey). As evidenced in Figure 2, the requirement for an oxidation catalyst is not cost effective for units with uncontrolled CO levels less than 6 ppmvd, based upon the value of $6,000/ton identified by EPA-Region II.

GE's CO guarantee is meant to accommodate operating conditions at all permitted ambient conditions and has a small margin to account for measurement error and machine and fuel variations. Generally for CO, extremely cold ambient conditions, concurrent with part load combustion turbine operations, will represent the worst-case emissions. GE's PG7241FA DLN turbine is one of the lowest emitting operating combustion turbines in simple cycle and combined cycle systems. These turbines are expected to operate near full load conditions for practically all of their operating hours. Consequently, GE's analysis shows that the CO emission levels from these combustion turbines can be tuned to be below 5 ppmvd. For any emission level below 5 ppmvd, the cost effectiveness will be greater than $8,000/ton of CO removed. Based on these considerations, GE is offering CO guarantees lower than its current "across the board" 9 ppmvd on a case-by-case basis following a detailed evaluation of the situation, thus validating its position that oxidation catalysts are not economically justified for CO emissions reduction for the PG7241FA, DLN units while firing natural gas.

6.0 Other Environmental Impacts

Use of oxidation catalysts to control CO emissions from GE PG7241FA DLN combustion turbines produces collateral impacts that are environmentally detrimental. A BACT analysis, by its definition, must include consideration of collateral environmental impacts. The EPA must consider the severity and resulting expense of these impacts when requiring controls for combustion turbines like GE's PG7241FA DLN machines. In this case, nitric oxide (NO) and sulfur dioxide (SO2) present in the exhaust will be oxidized by add-on catalysts to nitrogen dioxide (NO2) and sulfur trioxide (SO3), both of which promote the formation of acid rain. In addition, if applied in combination with selective catalytic reduction (SCR) for nitrogen oxides (NOx) control, ammonium salts formed as a result of ammonia (NH3) slip and SO3 will result in additional generation of PM10 and accelerated corrosion of the heat recovery steam generator (HRSG). The EPA identified this issue in its August 4, 2000, draft guidance "Consideration of Collateral Environmental Impacts Associated with the Use of SCR on Dry Low NOx Combined Cycle Gas Turbines," by John S. Sietz, Director, OAQPS. Finally, additional carbon dioxide (CO2) will be generated due to the output and efficiency losses associated with the pressure drop of the catalyst.

7.0 CO as a Public Health Concern

According to a health risks study conducted by a noted toxicologist in a May 2001, report (*"Carbon Monoxide Catalysis: Assessment of Need to Mitigate Public Health Risks Posed by Acute and Chronic Exposure to CO Emitted by Combined Cycle Natural Gas Turbines"*; R.A.Michaels, Ph.D., C.E.P., RAM TRAC Corporation, May 21, 2001), "Ground level CO concentrations arising from combined cycle natural gas turbines were found to be *below conservative standards and guidelines* limiting human exposure to airborne CO. CO also was found to be *below concentrations posing acute or chronic exposure risks to public health.*" These findings support the conclusion in the report that *"public health concerns do not justify requiring natural gas power generators to be equipped with CO catalysis to reduce ground level CO impacts.*" The health risks study was based on analysis of a CO emission rate of 9 ppmvd, which, as stated previously, is significantly higher than the uncontrolled emissions from GE's PG7241 DLN combustion turbines firing natural gas.

The following excerpt from page 23 of the RAM TRAC report summarizes the important conclusion that CO catalysts do nothing to improve public health:

> "...Risks posed to public health are quantified in this report to be zero, with or without CO catalysts. Indeed, this report reveals that ground level impacts of combined cycle natural gas turbines as modeled by GE are far from impacts which would be required to elicit adverse public health effects. Modeled turbine impacts would have to be increased by over an order of magnitude to elicit adverse effects associated herein with acute or chronic exposure to CO."

8.0 Other Considerations

Use of an oxidation catalyst reduces system efficiency and output. System inefficiencies and output losses, in turn, will result in an increase in emissions. Due to the increase in pressure drop associated with the oxidation catalyst in the exhaust gas path, output (MW) will decrease and heat rate (Btu/kW-hr) will increase. Since combustion turbines are recognized as the least polluting combustion sources to generate electricity, any attempt to make up the energy losses will increase emissions.

The installation and use of an oxidation catalyst will increase the cost of the electricity (COE) produced. With oxidation catalyst requirements on a new PG7241 DLN combustion turbine, the added capital and operating costs of the catalyst will be absorbed and paid for by the consumer. The higher cost of electricity will drive consumers to purchase cheaper electricity produced by older plants emitting higher levels of pollutants. This will occur because fewer new combined cycle plants will be built due to the increased capital cost and operation and maintenance costs resulting in high COE, and thus less electricity will be generated from the new plants that are built Therefore, total CO emissions will increase, not decrease, as a result of requiring oxidation catalysts on the new plants, as will emissions of acid rain pollutants and fine particulate matter. NOx, SO2, CO2, and mercury emissions will also increase on a national and regional basis due to continued operation of existing coal plants.

The use of an oxidation catalyst creates heavy metal wastes. Oxidation catalyst materials contain heavy metal oxides such as platinum and palladium, which are considered hazardous substances by the EPA. Handling, maintenance, cleaning, and disposal of the catalyst elements are harmful to humans and the environment. In addition, spent catalyst elements are considered hazardous waste, thus transferring an air emissions issue into a long-term solid waste disposal problem. When applied in combination with SCR, additional salt formation will occur. Ammonia salts cleaned from HRSGs are also wastes, which will need to be disposed of accordingly.

9.0 Summary

In summary, the use of an oxidation catalyst to control CO emissions from GE's PG7241FA DLN combustion turbines will not result in a measurable reduction of CO and will not substantially reduce ambient CO levels since minimal CO is emitted under normal operating conditions. The application of an oxidation catalyst on GE PG7241FA DLN combustion turbines firing natural gas in simple cycle and combined cycle plants is not cost effective, and produces collateral impacts, which are detrimental to the environment.

Appendix F
Compliance Monitoring Devices and/or Activities

1. Monitoring of emissions from these units will be performed pursuant to 40 CFR 60.334 and 40 CFR 75.

2. Applicable test methods used to determine compliance will be confined to those methods defined in 40 CFR 60-335.

WALDRON ENGINEERING, INC.
37 Industrial Drive
Exeter, NH 03833

Telephone (603) 772-7153
Facsimile (603) 772-7693

July 1, 2002

Mr Dave Graeber
10440 N. Central Expressway, Suite 1400
Dallas, TX 75231

Subject: 112-02; Spring Canyon Energy, plant water requirements.

Dear Dave:

Our evaluation of water usage at the proposed Spring Canyon Energy facility is based on the application of two GE Frame 7FA combustion turbine-generators with two heat recovery steam boilers and one steam turbine. This is known in the industry as a "two on one" combined cycle configuration. The gas turbines also utilize an inlet air chilling system to maintain higher power output under high ambient temperature operating conditions. In a combined cycle plant, steam is produced from gas turbine exhaust heat in each of the heat recovery steam boilers, and is piped to the inlet of the steam turbine to produce additional power from the waste heat. After expanding through the steam turbine, the exhaust steam is condensed in an air cooled condenser, and the liquid condensate is then returned to the heat recovery boiler as feed water to repeat the steam generation, expansion and condensing cycle.

In this plant design there are two primary uses which determine plant water requirements: a) Heat recovery steam boiler blow-down, and b) Wet cooling tower evaporation associated with the cooling process required for chilling combustion turbine inlet air. There is no water usage associated with the steam condensing process as this plant will utilize a dry type air cooled condenser specifically for the purpose of minimizing plant water consumption.

When the inlet air chilling system is not in service, the expected continuous plant water consumption is comprised of boiler blowdown. This mode of operation will consume about 80 gpm. This is represented on the attached estimated plant water balance for a 59F day with the inlet chiller off.

Under operating conditions whereby the inlet chilling system is brought into service, such as on a 100F day, plant water consumption is comprised of boiler blowdown plus wet cooling tower evaporation for cooling of the inlet air chilling system. The attached water balance for a 100F day represents this condition, requiring approximately 290 gpm from the plant water supply.

In order to arrive at an estimate of annual plant water usage, it is necessary to make a couple of assumptions about plant operating hours, and when the inlet chilling system will be in operation. In order to consider a worst case scenario, it is assumed that the plant would operate 8,760 hours per year (full time continuous). Further, it is assumed that the inlet chilling system will also be operating full time over a period of five months during the summer, from mid May through mid October. Under this very conservative scenario, the annual water consumption is calculated to be 88 million gallons. This figure translates to about 270 acre-feet of water, or a little less than half of the available 550 acre feet per year under the current supply contract terms. A copy of this worst case analysis is provided for reference.

Please contact me if you have any questions or need additional information.

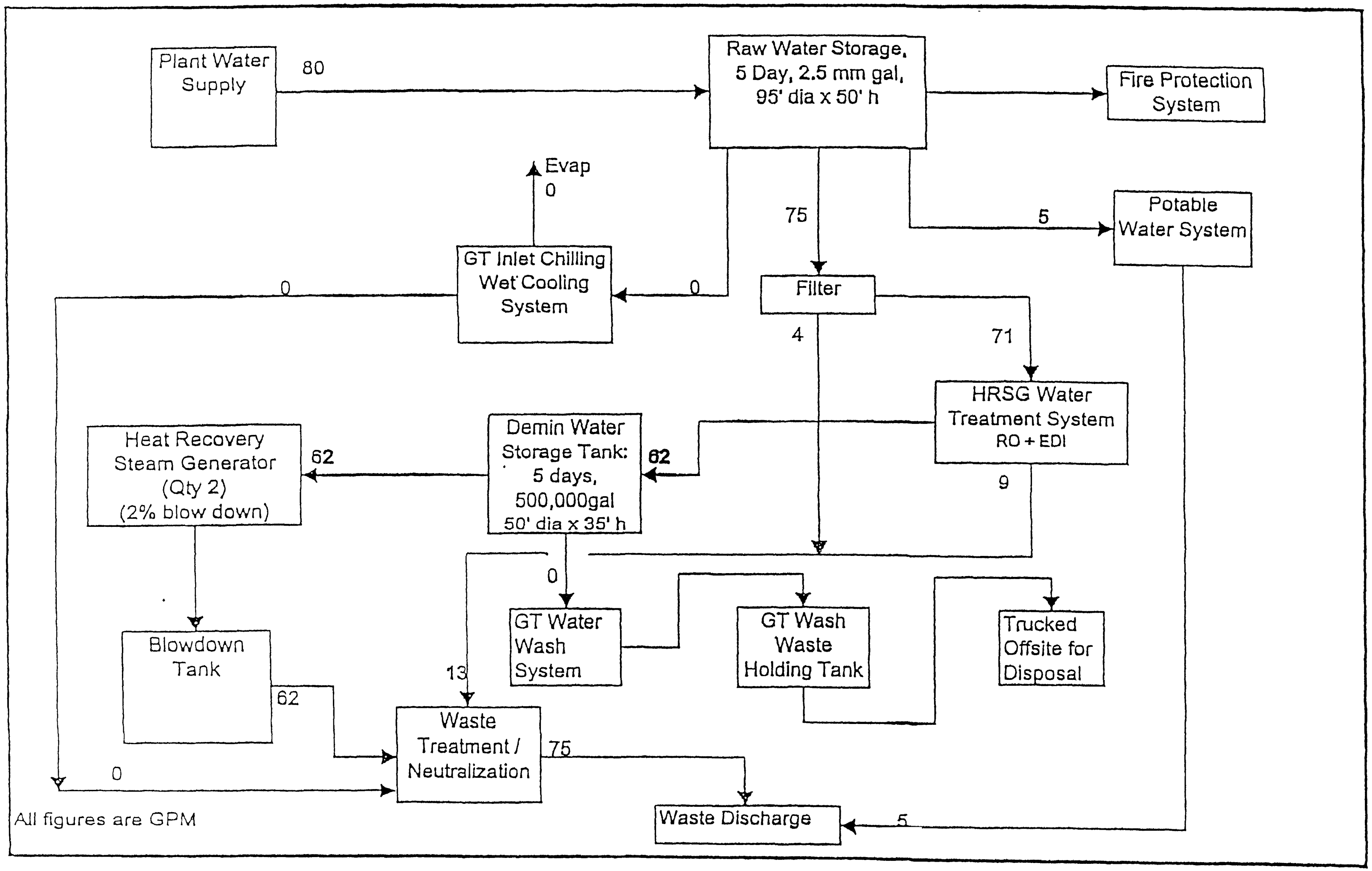
Sincerely,

R.F. Racine

Raymond F. Racine, PE
Project Manager
603-772-7153, Ext 118
email: rfr@waldroneng.com

Plant V. .r Balance

207FA Combined Cycle
59F - Chiller OFF



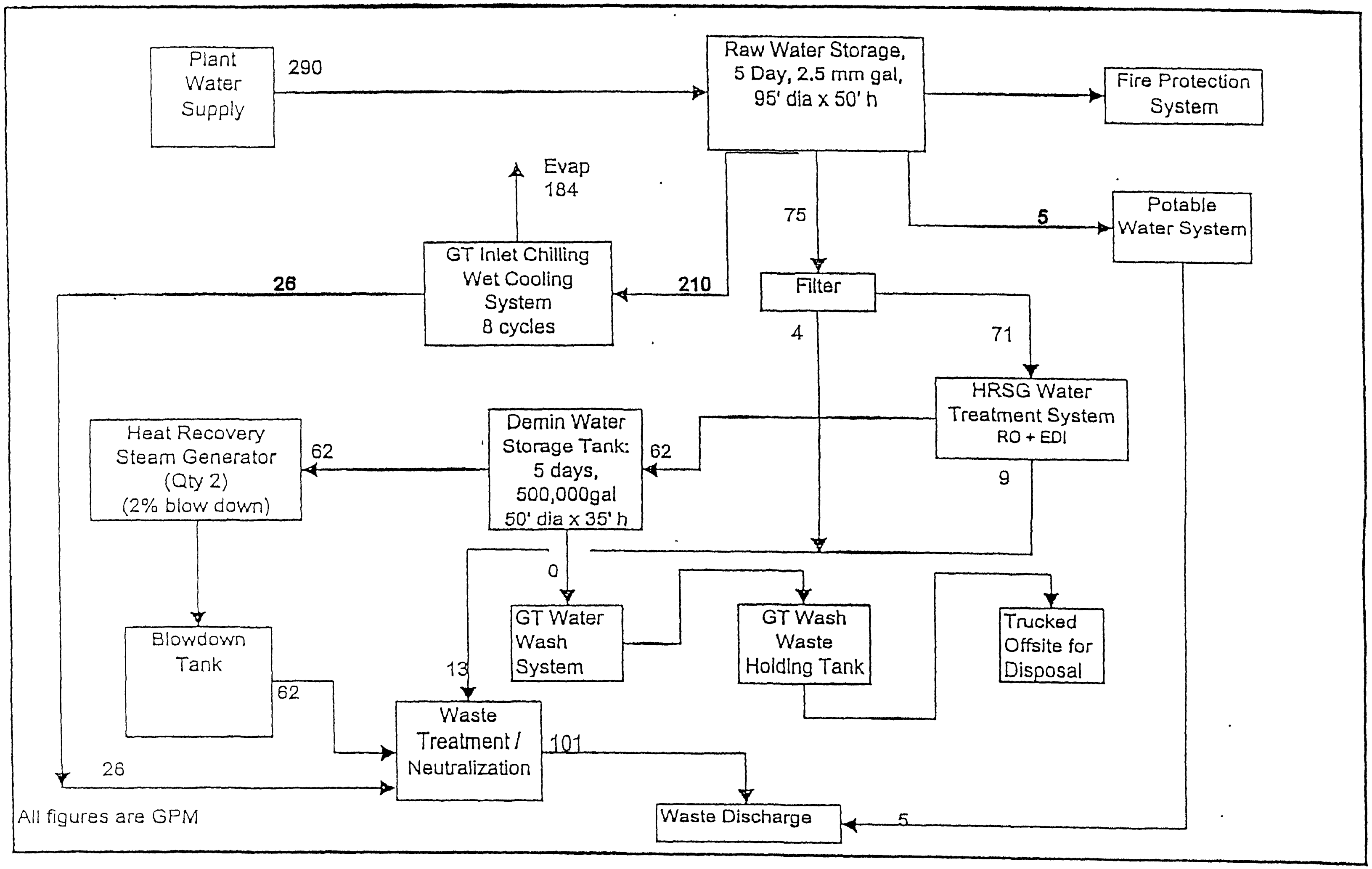
Waldron Engineering Inc
37 Industrial Drive
Exeter, NH 03842

Peak Electrical Generation
59F - Chiller OFF
11/29/01

1627

112-\ Water Balance,
Spring Canyon Energy
Preliminary Estimate

Plant W... Balance
207FA Combined Cycle
100F - Max Chilling



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Waldron Engineering Inc
37 Industrial Drive
Exeter, NH 03842

Peak Electrical Generation
100F - Max Chilling
11/29/01

Waleru _je Spring Canyon-Proj Bk
Expected Case

	1	Acre foot =	43,560	Cu Ft	
	1	Cu Ft =	7.48	Gal	
Acre Feet		550	per year	<= Water available	
Volume	23,958,000	Cu Ft		179,206	kgal

Data for Spring Canyon Project:

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Avg daily F	28.0	33.3	40.5	48.6	57.2	67.1	75.4	73.2	63.7	52.2	39.6	29.7	50.5
Avg max F	39 6	45.0	53.6	63.1	73.0	84.6	93.0	90.9	80.8	68.4	52.2	41.0	65.5
Operating Profile.													
Op'n factor	0.30	0.30	0.50	0.70	0.80	1.00	1.00	1.00	1.00	0.70	0 50	0.30	
Hours/mo	730	730	730	730	730	730	730	730	730	730	730	730	
Op'n Hours	**219**	**219**	**365**	**511**	**584**	**730**	**730**	**730**	**730**	**511**	**365**	**219**	**5913**
Chill Opn factor	-	-	-	-	0.20	0.30	0.60	0.60	0.60	0 20	-	-	
Chiller Hours	**0**	**0**	**0**	**0**	**116.8**	**219**	**438**	**438**	**438**	**102.2**	**0**	**0**	**1752**
Firing factor	-	-	-	-	0.30	0.40	0.60	0.60	0 40	0.30	-	-	
Fired Hours	**0**	**0**	**0**	**0**	**219**	**292**	**438**	**438**	**292**	**219**	**0**	**0**	**1898**

CC Make-up, gpm	75	75	75	75	75	75	75	75	75	75	75	75	
Make-up, kgal	986	986	1,643	2,300	2,628	3,285	3,285	3,285	3,285	2,300	1,643	986	**26,609**
Inlet Chill CT evap, gpm	184	184	184	184	184	184	184	184	184	184	184	184	
Evap Loss, kgal	-	-	-	-	1,289	2,418	4,836	4,836	4,836	1,128	-	-	**19,342**

Tot Annual Use, kgal	**45,951**
Percent of Available	**26%**

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Spring Canyon Water Balance
Worst Case

	1	Acre foot =	43,560	Cu Ft
	1	Cu Ft =	7.48	Gal
Acre Feet		550	per year	<= Water available
Volume		23,958,000	Cu Ft	179,206 kgal

Data for Spring Canyon Project:

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Avg daily F	28.0	33.3	40.5	48.6	57.2	67.1	75.4	73.2	63.7	52.2	39.6	29.7	50.5
Avg max F	39.6	45.0	53.6	63.1	73.0	84.6	93.0	90.9	80.8	68.4	52.2	41 0	65.5
Operating Profile.													
Op'n factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	
Hours/mo	730	730	730	730	730	730	730	730	730	730	730	730	
Op'n Hours	730	730	730	730	730	730	730	730	730	730	730	730	8760
Chill Opn factor	-	-	-	-	0.50	1.00	1.00	1.00	1.00	0.50	-	-	
Chiller Hours	0	0	0	0	365	730	730	730	730	365	0	0	3650
Firing factor	-	-	-	-	-	1.00	1.00	1.00	1.00	-	-	-	
Fired Hours	0	0	0	0	0	730	730	730	730	0	0	0	2920

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
CC Make-up, gpm	80	80	80	80	80	80	80	80	80	80	80	80	
Make-up, kgal	3,504	3,504	3,504	3,504	3,504	3,504	3,504	3,504	3,504	3,504	3,504	3,504	42,048
Inlet Chill CT evap, gpm	210	210	210	210	210	210	210	210	210	210	210	210	
Evap Loss, kgal	-	-	-	-	4,599	9,198	9,198	9,198	9,198	4,599	-	-	45,990
Max use	290												
Boiler only	80												

Tot Annual Use, kgal	88,038
Percent of Available	49%

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Waste Water Chemistry

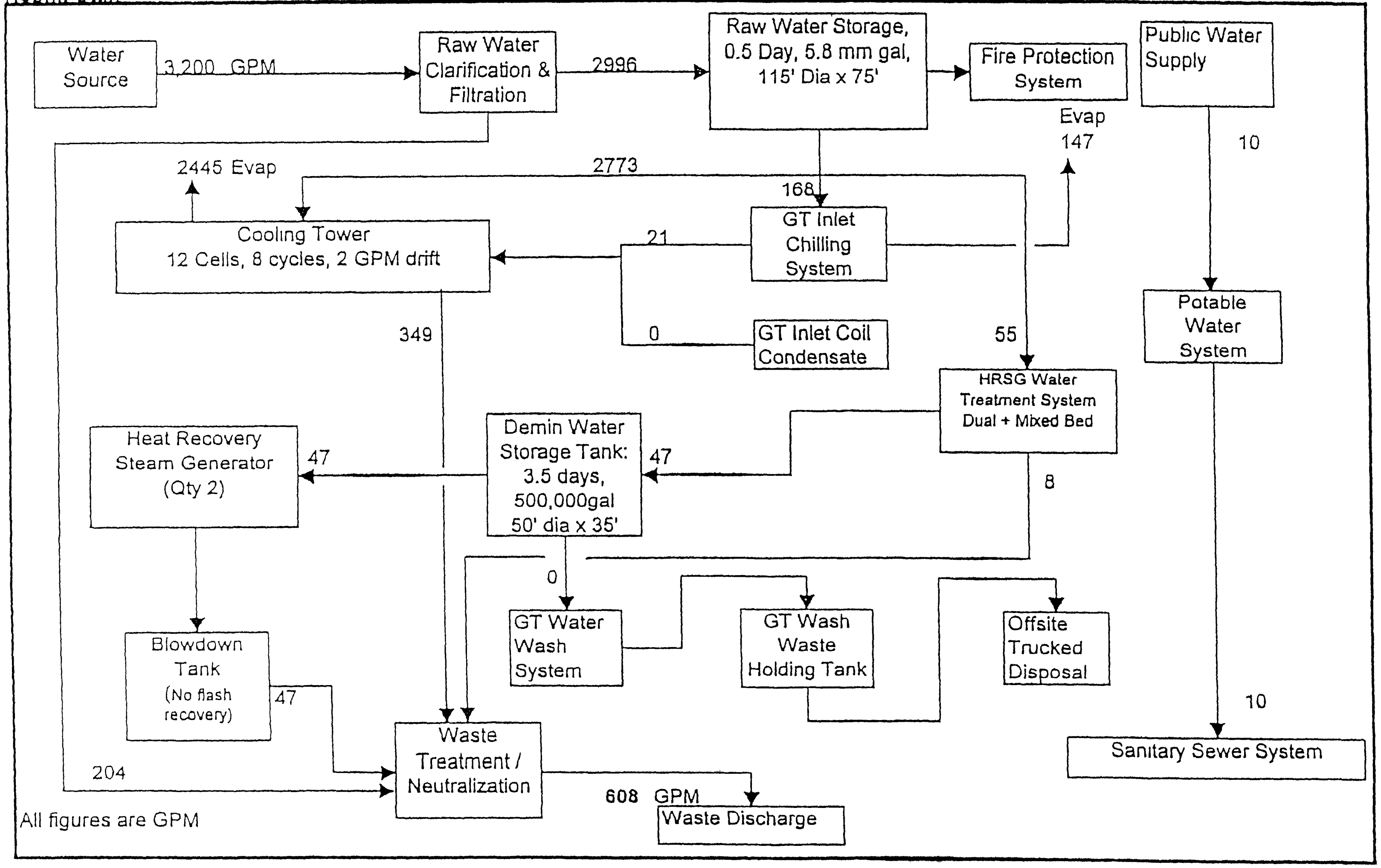
Developer: Waldron Engineering/USA Power
Location: Nephi, Utah
Project: Hypothetical Only Water Analysis Required
Project Location:
Days of Operation: 365
Revision: 8 cycles CT Operation

											Waste Water Totals			
	Include(Yes/No)	YES	NO	YES	YES	YES	NO				Flows			
	Percent of Flow	85.9606%	0.0000%	0.2463%	1.7241%	12.0690%	0.0000%	0.0000%	0.0000%	0.0000%				
	Gpm	349.00		1.00	7.00	49.00	0				406.00	gpm		
	M3/hr	79.32		0.23	1.59	11.14	0.00	0.00	0.00	0.00	92.27	M3/hr		
		Cooling Tower BD	RO Reject	Mixed Bed Waste	Dual Bed Waste	HRSG BD	Once Through						Values below are per DAY	
Cations as CaCO3											ppm CaCO3	ppm Ion	pounds as ion	kgr as ion
Al	Aluminum	0.000	0.000	0.000	0.000	0.000	0.000				0.000	0.00	0.0	0.0
NH4	Ammonia	0.000	0.000	0.000	0.000	0.000	0.000				0.000	0.00	0.0	0.0
As	Arsenic	0.080	0.000	0.005	0.020	0.000	0.000				0.069	0.03	0.2	0.1
Ba	Barium	0.000	0.000	0.000	0.000	0.000	0.000				0.000	0.00	0.0	0.0
B	Boron	0.000	0.000	0.000	0.000	0.000	0.000				0.000	0.00	0.0	0.0
Ca	Calcium	800.000	0.000	50.000	202.767	0.000	0.000				694.923	277.97	1 355.3	614.6
Cd	Cadmium	0.010	0.000	0.001	0.003	0.000	0.000				0.009	0.01	0.0	0.0
Co	Cobalt	0.054	0.000	0.003	0.014	0.000	0.000				0.047	0.03	0.1	0.1
Cu	Copper(cupric)	0.063	0.000	0.004	0.016	0.000	0.000				0.055	0.04	0.2	0.1
Cr	Chromium	0.254	0.000	0.016	0.064	0.000	0.000				0.221	0.08	0.4	0.2
Au	Gold	0.000	0.000	0.000	0.000	0.000	0.000				0.000	0.00	0.0	0.0
Fe	Iron(ferrous)	0.000	0.000	0.000	0.000	0.000	0.000				0.000	0.00	0.0	0.0
Pb	Lead	0.042	0.000	0.003	0.011	0.000	0.000				0.037	0.08	0.4	0.2
Li	Lithium	0.000	0.000	0.000	0.000	0.000	0.000				0.000	0.00	0.0	0.0
Mg	Magnesium	407.056	0.000	25.441	103.172	0.000	0.000				353.591	84.86	413.8	187.6
Mn	Manganese(Manganous)	0.000	0.000	0.000	0.000	0.000	0.000				0.000	0.00	0.0	0.0
Hg	Mercury	0.008	0.000	0.001	0.002	0.000	0.000				0.007	0.01	0.1	0.0
Mo	Molybdenum	0.000	0.000	0.000	0.000	0.000	0.000				0.000	0.00	0.0	0.0
Ni	Nickel	0.178	0.000	0.011	0.045	0.000	0.000				0.164	0.09	0.4	0.2
K	Potassium	108.032	0.000	6.752	27.382	0.000	0.000				93.842	73.20	356.9	161.9
Se	Selenium	0.334	0.000	0.021	0.085	0.000	0.000				0.290	0.08	0.4	0.2
Ag	Silver	0.018	0.000	0.001	0.005	0.000	0.000				0.016	0.03	0.2	0.1
Na	Sodium	1501.363	0.000	945.050	4052.733	14.000	0.000				1480.501	681.03	3 320.5	1 505.9
Sr	Strontium	0.000	0.000	0.000	0.000	0.000	0.000				0.000	0.00	0.0	0.0
Tl	Thallium(thallic)	0.012	0.000	0.001	0.003	0.000	0.000				0.010	0.01	0.1	0.0
Sn	Tin	0.000	0.000	0.000	0.000	0.000	0.000				0.000	0.00	0.0	0.0
Ti	Titanium	0.000	0.000	0.000	0.000	0.000	0.000				0.000	0.00	0.0	0.0
V	Vanadium	0.000	0.000	0.000	0.000	0.000	0.000				0.000	0.00	0.0	0.0
Zn	Zinc	0.135	0.000	0.008	0.034	0.000	0.000				0.117	0.08	0.4	0.2
Sum of Cations		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Anions														
HCO3	Bicarbonate	200.000	0.000	31.180	126.384	5.000	0.000				177.811	216.93	1 057.7	479.7
B4O7	Borate	0.000	0.000	0.000	0.000	0.000	0.000				0.000	0.00	0.0	0.0
Br	Bromide	0.000	0.000	0.000	0.000	0.000	0.000				0.000	0.00	0.0	0.0
CO3	Carbonate	0.000	0.000	0.000	0.000	0.000	0.000				0.000	0.00	0.0	0.0
OH	Hydrate	0.000	0.000	0.000	0.000	0.000	0.000				0.000	0.00	0.0	0.0
Cl	Chloride	998.407	0.000	61.139	247.939	5.000	0.000				867.498	615.92	3 003.0	1 361.9
F	Fluoride	0.000	0.000	0.000	0.000	0.000	0.000				0.000	0.00	0.0	0.0
MoO4	Molybdate	0.000	0.000	0.000	0.000	0.000	0.000				0.000	0.00	0.0	0.0
NO3	Nitrate	5.832	0.000	0.365	1.478	0.000	0.000				5.068	6.28	30.6	13.9
NO2	Nitrite	6.048	0.000	0.378	1.533	0.000	0.000				5.254	4.89	23.8	10.8
PO4	Phosphate (as PO4)	12.000	0.000	0.000	0.000	4.000	0.000				10.656	6.71	32.7	14.8
P	Phosphorous (Valence 3)	14.737	0.000	0.921	3.735	0.000	0				12.801	2.69	13.1	5.9
SO4	Sulfate	1679.837	0.000	926.657	3990.565	0.000	0.000				1543.429	1481.69	7 224.2	3 276.3
SiO2	Reactive Silica	83.000	0.000	5.188	21.037	0.000	0.000				72.098	86.52	421.8	191.3
Sum of Anions		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
											TDS	3452.74		
Cooling Tower Control Levels of Chemical Additives														
	PO4	10.0												
	Zinc	0.0												
	Organo-PO4	2.0												
	Tolyltriazole	0.0												
	Polymer	0.0												

Hypothetical Only,
Water Analysis Required.
Nephi, Utah

Plant Water Balance

207FA Combined Cycle



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102822

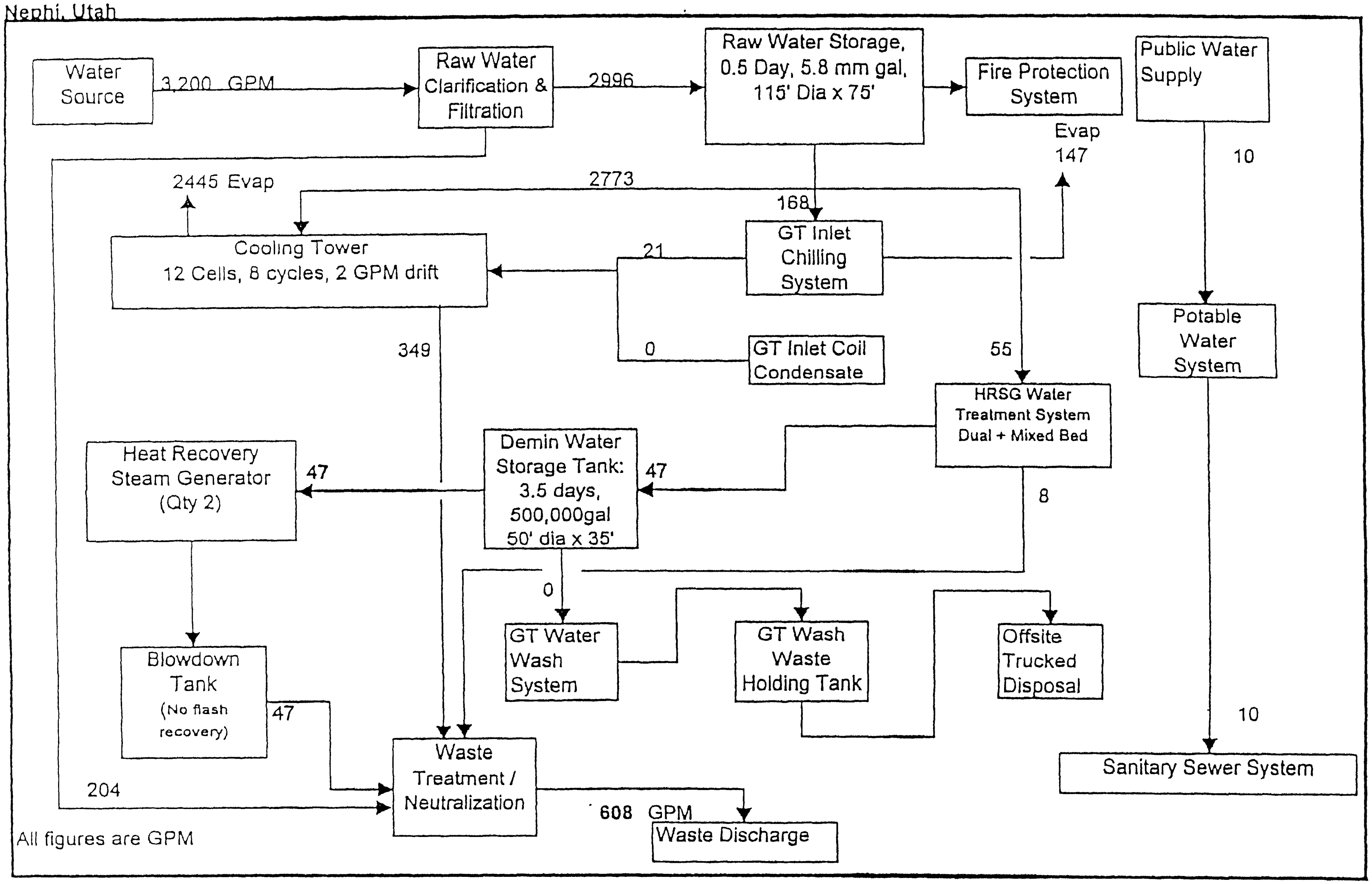
Waldron Engineering Inc
32 Depot Square
Hampton, NH 03842

TYPICAL ONLY
Water Balance - 8 Cycles
9/14/01

Hypothetical Only,
Water Analysis Required.
Nephi, Utah

Plant Water Balance

207FA Combined Cycle



Waldron Engineering Inc
32 Depot Square
Hampton, NH 03842

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TYPICAL ONLY
Water Balance - 8 Cycles
9/14/01

10283

Estimator 2000© Cost Estimate

Data Input Sheet

This report is designed to calculate operating data and cost estimates for boiler and cooling water systems in independent power plants.
Enter all the data in following sections.

Chemical Process Summary

Project Information

Developer:	Waldron Engineering/USA Power
Location:	Nephi, Utah
Project ID:	*Hypothetical Only; Water Analysis Required*
Project Location:	
Revision:	

Operation Information

Boiler Information

HRSG Treatment Product Information

Function	Name	Local cost/kg	US $/lb	Density lb/gal	Density kg/L
Phosphate Treatment Product	Nalco BT-4000			9.10	1.09
O2 Scavenger Product	Elimin-Ox			8.50	1.02
Amine Treatment Product	Nalco 356			8.20	0.98
Dispersant Product	(none)				
Other	(none)				

Field Erected & Package Boiler Treatment Product Information

Function	Name	Local cost/kg	US $/lb	Density lb/gal	Density kg/L
Phosphate Treatment Product					
O2 Scavenger Product					
Amine Treatment Product					
Dispersant Product					
Other					

Auxiliary Boiler Treatment Product Information

Function	Name	Local cost/kg	US $/lb	Density lb/gal	Density kg/L
Phosphate Treatment Product	.				
O2 Scavenger Product					
Amine Treatment Product					
Dispersant Product					
Other					

Once Through Cooling System

8.1 Once Through Chemical Treatment Program

Function	Name	Local cost/kg	US $/lb	Density lb/gal	Density kg/L
Oxidizer					
Acti-Brom					
Bio-Dispersants					
Other					

Raw Water Treatment

Raw Water Chlorination

Function	Name	Local Cost/kg	US $/lb	Density lb/gal	Density kg/L
Oxidizer					
...ion Control					
...sant					

Multimedia Filters

Function	Name	Local Cost/kg	US $/lb	Density lb/gal	Dosage ppm
Oxidizer	(none)				
Coagulant #1	(none)				
Coagulant #2	(none)				
Flocculant	(none)	0	0		0
Media	Sand/Antharcite	$35.00	$/cu ft	1236.01	local/M3

Green Sand Filters

Function	Name	Local Cost/kg	US $/lb	Density lb/gal	Density kg/L
Pre-Chlorination					
Potassium Permanganate					
Other					
Media			$/cu ft		local/M3
Pre-chlorination ?	NO				

Contact Clarifier

Function	Name	Local Cost/kg	US $/lb	Density lb/gal	Density kg/L
Chlorination	Bleach 12.5 %			9.90	1.19
Coagulant 1	Alum-dry basis				
Coagulant 2	Nalco 8105			8.80	1.05
Flocculant	Nalco 8110				
pH Control	(none)				

Lime Softening

Function	Name	Local Cost/kg	US $/lb	Density lb/gal	Density kg/L
Chlorination					
Lime					
Magnesium Oxide					
Soda Ash					
Caustic Soda					
Coagulant 1					
Coagulant 2					
Flocculant					
pH Adjustment					

Carbon Filters

Function	Name	Local Cost/kg	US $/lb	Density lb/gal	Density kg/L
Biological Control					
...tant					
...tant					
Media			$/cu ft		local/M3

Recirculating Cooling Water System

Cooling Product Information

Function	Name	Local Cost/kg	US$/lb	Density lb/gal	Density kg/L
Scale/Corrosion Control	Nalco PCL-402			9.70	1.16
Dispersant	(none)				
Corrosion Control	Nalco CL-50			9.00	1.08
Oxidizer	Bleach - 12.5%			9.90	1.19
Other Bio Control	(none)				
Other	(none)				
Acid for pH Control (note 1)	H2SO4 66 Be'			15.26	1.83

Slug Feed Treatment	Name	Local Cost/kg	US $/lb	Density lb/gal	Density kg/L
Biocide	(none)				
Other	(none)				

Note 1: Acid dosage is ppm acid per ppm alkalinity reduction of make up water

Closed Loop Cooling System

Closed Loop Chemical Program

Function	Name	Local Cost/kg	US $/lb	Density lb/gal	Density kg/L
Corrosion Inhibitor	.				
Biocide					
Other					
Biocide Additions per Year					

Ion Exchange

Cation Ion Exchange

Unit Type 0

Function	Name	Local Cost/kg	US $/lb	Resin $/cu ft	ppm, cap or lb/cuft
Cation Resin					
Regenerant					
Dechlorination					
Cleaner					

Dual Bed Demineralizer

Function	Name	Local Cost/kg	US $/lb	Resin $/cu ft	ppm, cap or lb/cuft
Dechlorination	Nalco 7408				4 ppm
Cation Resin	DowexMarathon C (H)				16500 gr/cu.ft.
Regenerant	H2SO4 66 Be'				8 lb/cu.f.t
Anion Resin	Dowex Marathon A (Cl)				13500 gr/cu.ft.
Regenerant	Caustic Soda (liquid 50%)				8 lb/cu ft.
Cation Cleaner	(none)				
Anion Cleaner	(none)				
Decarbonator ?	YES				

Mixed Bed Demineralizer

Function	Name	Local Cost/kg	US $/lb	Resin $/cu ft	capacity-gr. or lb/cuft
Cation Resin	DowexMarathon C (H)				17500 gr/cu.ft.
Regenerant	H2SO4 66 Be'				8 lb/cu.ft.
Anion resin	Dowex Marathon A MB (Cl)				14500 gr/cu.ft.
Regenerant	Caustic Soda (liquid 50%)				8 lb/cu.ft.

RO System

Function	Name	Local Cost/kg	US $/lb	Density lb/gal	Density kg/L
pH Adjustment					
Antiscalant					
Bio Control					
Dechlorination					

Item	Name	Cost	Units
Membrane			US $/element
Pretreatment Filters			US $/TIE
	Electric Power		US $/kWh
	Recovery		%

Sea Water RO Only

	Primary % Recovery		%
	Secondary % Recovery		%
User Defined			
User Defined			
User Defined			
User Defined			
User Defined			

10000067-2

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ORDINANCE NO. 7-01-02

AN ORDINANCE CHANGING THE ZONING FOR CERTAIN PROPERTIES IN SECTION 23, TOWNSHIP 11 SOUTH, RANGE 1 WEST FROM GMRF TO ID.

WHEREFORE, after a duly noticed public hearing and in conformity with the Juab County General Plan, the subject property is found suited for industrial development.

BE IT ORDAINED BY THE BOARD OF JUAB COUNTY COMMISSIONERS AS FOLLOWS:

The zoning of the following described property is hereby changed from GMRF to ID:

> NE ¼ of the SE ¼ of Section 34, Township 11 S Range 1 West, Salt Lake Baseline and Meridian, containing an area of 40 acres more or less.

The Juab County Zoning Map shall be amended accordingly.

EFFECTIVE DATE: This ordinance shall take effect within 30 days or upon publication, whichever is shorter.

Passed and approved this 1st day of July, 2002.

William Boyd Howarth

William Boyd Howarth, Commission Chairman

Attest:

Patricia M Ingram

Patricia M Ingram, Juab County Clerk

SWCA ENVIRONMENTAL CONSULTANTS

Salt Lake City Office
230 South 500 East, Suite 380
Salt Lake City, Utah 84102 2015
Tel 801 322 4307 Fax 801 322 4308
www swca com

June 20, 2002

Mr. F. David Graeber
Principal
USA Power
10440 North Central Expressway, Suite 1400
Dallas, TX 75231

Dear Mr. Graeber;

SWCA, Inc. Environmental Consultants has prepared this letter report that outlines the permit/approval requirements necessary to construct and operate the proposed Spring Canyon Energy Project near Mona, Utah. The permit descriptions are divided by federal and state jurisdictions and include the name of the permit or approval, granting agency, a narrative of the process and issues, and the likely time requirements. This report does not include the ongoing air quality, water rights transfer, or county conditional use permit processes.

I. FEDERAL

A. **Permit/Approval:** Right-of-Way Grant

Granting Agency: Bureau of Land Management (BLM) – Salt Lake Field Office

Process/Issues: The attached map illustrates the BLM-managed lands crossed by the project. As indicated on the map, the project includes a natural gas pipeline and an electrical transmission power line. The pipeline will traverse approximately five miles and the power line will traverse approximately one mile of BLM-administered land, respectively. The applicant submits a Form 299 Right-of-way Application that describes the proposed project. The BLM will require a Plan of Development (POD) be submitted as part of the complete right-of-way application. The POD outlines the purpose and need for the project and procedures from construction through reclamation and operation.

The BLM is mandated by the National Environmental Policy Act (NEPA) to analyze environmental impacts of the proposed action. SWCA contacted Alice Stephenson, NEPA Coordinator for the BLM Salt Lake Field Office, to determine the appropriate NEPA

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process for the project. Based on this conversation, we determined an Environmental Assessment (EA) would likely be required as part of the project impact disclosure and permitting process. An EA is produced for uncomplicated, non-controversial projects expected not to have significant environmental impacts. In the majority of cases, an EA results in a Finding of No Significant Impact (FONSI) and fulfills the federal agency's NEPA requirements.

The EA analyzes existing conditions and potential environmental impacts on 13 critical elements according to the BLM NEPA Guidelines. The 13 critical elements include:

- Air Quality
- Areas of Critical Environmental Concern
- Cultural Resources
- Farm Lands
- Floodplains
- Environmental Justice
- Invasive, Non-native Species
- Native American Religious Concerns
- Threatened, Endangered or Candidate Species
- Hazardous or Solid Wastes
- Water Quality
- Wetlands/Riparian
- Wild and Scenic Rivers
- Wilderness

This EA process will satisfy many other federal regulations triggered by the BLM right-of-way application. Cultural resources inventories and analysis will be completed to satisfy the National Historic Preservation Act including Native American consultations. The Utah State Historic Preservation Office will be required to review and concur with the cultural resources investigations and findings. Threatened and endangered species surveys and consultations will be completed to satisfy the Endangered Species Act. Wetland delineations will be completed to satisfy portions of the Clean Water Act (see Joint Stream Alteration Permit).

The BLM may conduct a 30-day scoping period to solicit public input on the project during the initial phase of the NEPA process. Additionally, the BLM may allow 30 days for public comment on the Draft EA. Based on SWCA's understanding of Spring Canyon Energy's proposed project and extensive experience with the BLM and similar pipeline projects in the project area, we believe a relatively simple EA process will satisfy the BLM's NEPA obligations.

Time Requirement: To expedite the preparation of the EA, a third party environmental consultant can be contracted by the applicant to prepare the EA on behalf of the BLM. The timing of this process is highly dependent on the coordination and cooperation between the applicant, third-party consultant, and the BLM. The proposed natural gas and power transmission lines parallel an existing overhead power line corridor and have recently been surveyed by SWCA for a proposed petroleum products pipeline. SWCA inventoried the project area for cultural resources, wetlands, and threatened and endangered species. Given SWCA's recent survey work in the project area, it is our opinion that the proposed project would result in a Finding of No Significant Impact and the process could be completed within 3 to 6 months.

II. STATE OF UTAH

A. Permit/Approval: **Right-of-Way Easement**

Granting Agency: School and Institutional Trust Lands Administration (SITLA)

Process/Issues: The attached map illustrates the proposed natural gas pipeline crosses less than a half-mile of SITLA-managed land. The applicant submits an easement application to SITLA and is required to complete cultural resource investigations and threatened and endangered species investigations. The investigations required for the BLM EA process will satisfy the SITLA requirements. In SWCA's experience, obtaining a utility easement from SITLA has not been problematic.

Time Requirement: SITLA estimates 90 days to process this application following the completion of the appropriate investigations.

B. Permit/Approval: **Joint Stream Alteration Permit**

Granting Agency: Utah Department of Natural Resources Division of Water Rights and the U.S. Army Corps of Engineers

Process/Issues: The attached map illustrates several stream crossings along the proposed natural gas pipeline route. The State of Utah Division of Water Rights and the U.S. Army Corps of Engineers (COE) have a joint application procedure for permitting impacts to Waters of the United States including jurisdictional wetlands. A Waters of the U.S. and jurisdiction wetland delineation is completed according to the COE's requirements. The application is submitted to the Division of Water Rights and the Division routes the application to the COE, U.S. Fish and Wildlife Service, and other State agencies for comment. A follow-up inspection by the Division of Water Rights is required upon completion of the construction and rehabilitation. This process is routine for all stream alteration activities.

Time Requirement: There are no permanent, aboveground impacts to wetlands; therefore the completed application can be processed within 30-45 days.

C. Permit/Approval: Construction Storm Water Discharge Permit

Granting Agency: Utah Department of Environmental Quality, Division of Water Quality

Process/Issues: In the State of Utah the EPA granted jurisdiction of the National Pollution Discharge Elimination System (NPDES) portion of the Clean Water Act to the Utah Department of Environmental Quality, Division of Water Quality (DWQ). A permit is required for construction activities involving greater than 5 acres of ground disturbance. The applicant is required to prepare a Storm Water Pollution Prevention Plan (SWPPP), to have available on site during construction activities. The applicant is required to submit a Notice of Intent (NOI) to the DWQ describing the project. This permit applies to construction activities, in this case, the pipeline, power line, and plant site construction. The DWQ may visit the site at any time for a site inspection and the applicant is required to perform and document routine inspections. A Notice of Termination is required when the site has been successfully stabilized. There is no agency review process associated with obtaining a Construction Storm Water Discharge Permit.

Time Requirement: Authorization to discharge is effective immediately after the NOI is received by the DWQ along with the appropriate permit fee.

D. Permit/Approval: General Multi-Sector Industrial Storm Water Discharge Permit

Granting Agency: Utah Department of Environmental Quality, Division of Water Quality

Process/Issues: Similar to the construction storm water discharge permit, however, this permit only applies to the plant site. The industrial storm water discharge permit applies to the long-term operation and handling of storm water on the plant site. The applicant is required to prepare a plan to have available on site during the long-term operation of the plant. There is no agency review process associated with obtaining a General Multi-Sector Industrial Storm Water Discharge Permit.

Time Requirement: Authorization to discharge is effective immediately after the NOI is received by the DWQ along with the appropriate permit fee.

E. **Permit/Approval:** Trench Dewatering/Hydrostatic Test Water Discharge Permit

Granting Agency: Utah Department of Environmental Quality Division of Water Quality

Process/Issues: This permit is required for discharging groundwater and/or hydrostatic test water from construction activities to streams, creeks, canals, ditches, storm drains, or wetlands. A Notice of Intent is prepared that describes the nature of the activity and likely discharge points and rates. The permit requires that water quality sampling is performed and that the discharge meets appropriate water quality standards. The sampling data must be reported to the Division of Water Quality on a monthly basis. A Notice of Termination is required at the completion of the work.

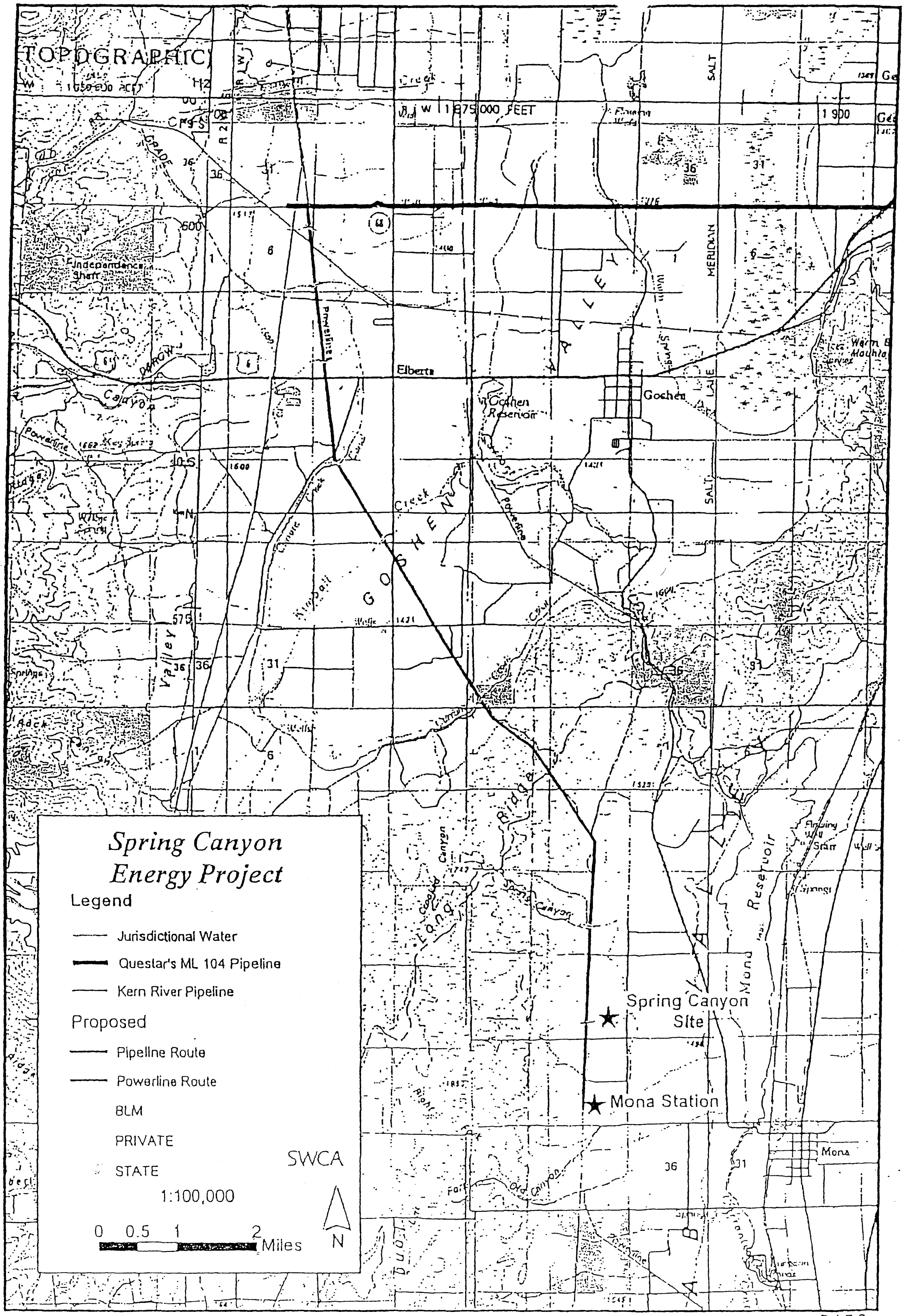
Time Requirement: A permit is typically granted with 30 days of the Notice of Intent being submitted.

If you have any questions regarding the information contained in this report, please feel free to contact me at (801) 322-4307 ext. 206.

Sincerely,

David N. Holland
Program Director

Attachment



I:/USApwr_springcanyon/maps/proj_loc.mxd (6-7-2001)

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Tab 8

Timeline of Events

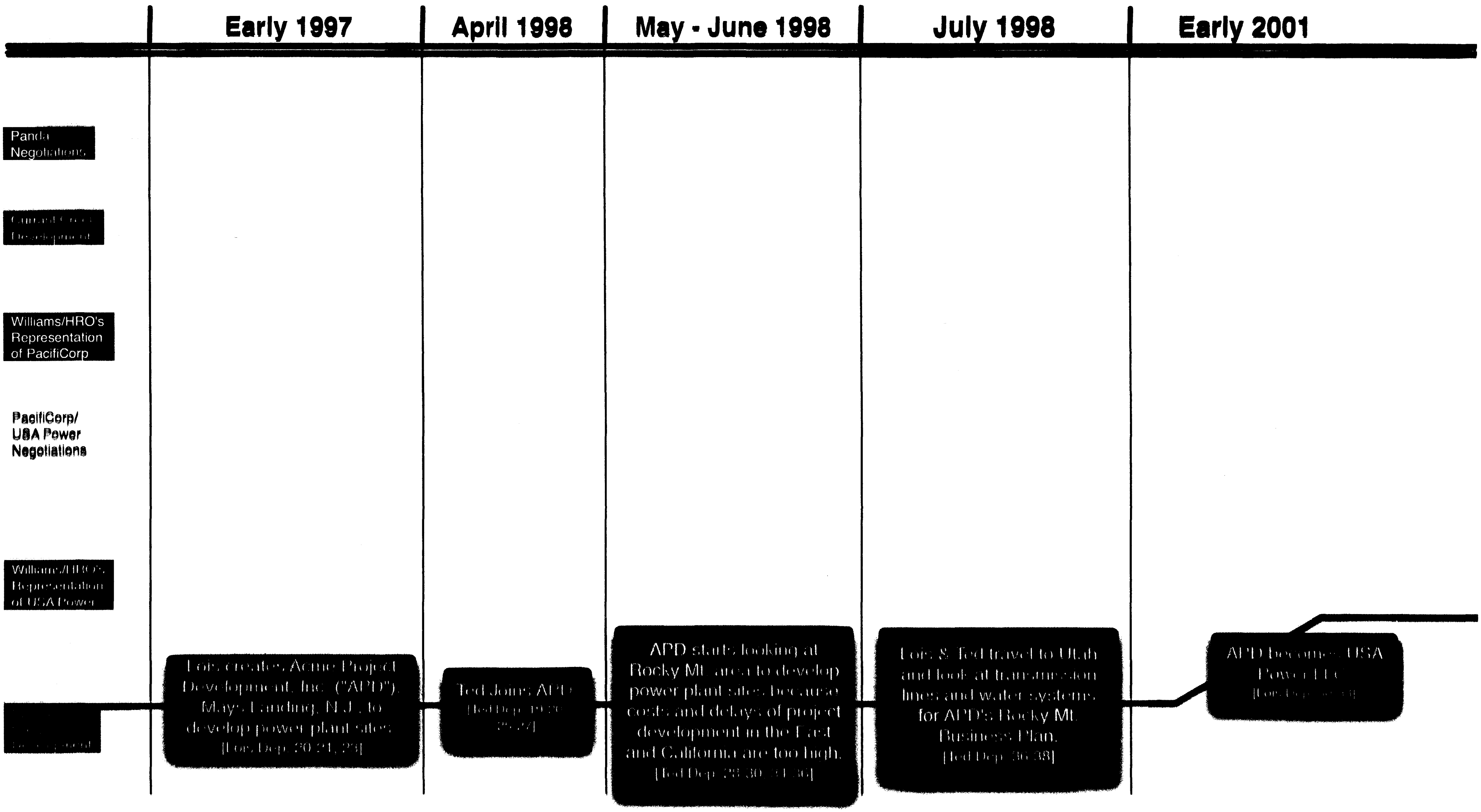
USA Power v. PacifiCorp, Jody Williams, and Holme, Roberts & Owen, LLP

Issue Key:

1. PacifiCorp's Negotiations with Panda Energy
2. PacifiCorp's Development of Currant Creek
3. Williams/HRO's Representation of PacifiCorp
4. Negotiations between USA Power and PacifiCorp
5. Williams/HRO's Representation of USA Power
6. USA Power's Development of Spring Canyon

Abbreviations:

Dave = Dave Graeber
HRO = Holme, Roberts & Owen
Lois = Lois Banasiewicz
PaC = PacifiCorp
Spring Canyon = Spring Canyon Energy Development in Mona
Ted = Ted Banasiewicz
Thurgood = Rand Thurgood
USA = USA Power
Williams = Jody Williams



Early 1997
April 1998
May - June 1998
July 1998
Early 2001
Panda Negotiations
Williams/HRO's Representation of PacifiCorp
PacifiCorp/ USA Power Negotiations
Lois creates Acme Project Development, Inc. ("APD"), Mays Landing, N.J., to develop power plant sites.
[Lois Dep. 20-21, 23]
Ted Joins APD
APD starts looking at Rocky Mt. area to develop power plant sites because costs and delays of project development in the East and California are too high.
Lois & Ted travel to Utah and look at transmission lines and water systems for APD's Rocky Mt. Business Plan.
[Ted Dep. 36-38]
APD becomes USA Power LLC

	March 2001	April 2001	4/30/2001	May 2001	5/1/2001
Panda Negotiations					
Currant Creek Development					
Williams/HRO's Representation of PacifiCorp					
PacifiCorp/ USA Power Negotiations					
Williams/HRO's Representation of USA Power		USA hires Williams as its lawyer for USA's power plant development in Utah. [Exs. 23, 47; Ted Dep. 54-59]	Williams sends USA invoice for legal services performed for USA's power plant development in Utah. [Ex. 47]	Williams meets with USA development team re: "All of the issues associated with the project and . . . how [to] . . . move on to the next step with each issue." [See Ted Dep. 68, 74-75, 78-79]	Williams' client information sheet describes subject matter of USA representation as "Power Plant." [Ex. 22]
[illegible]	USA Power LLC forms USA Power Partners, LLC to develop power plant sites in Rocky Mountain area [Exs. 131, 134; Lor. Dep. 78-46] • Sooner Power Partners, LLC financing member - capitalized $950,000 by 03/01 [Ex. 133] • USA Power LLC member/ manager. [Ex. 133; Lor. Dep. 92-99]	USA develops site-specific design for Spring Canyon Plant, including plant capacity [illegible] 539 MWs), fuel type (gas-fired)		USA development tea[illegible] [Ted Dep. 68, 71-75[illegible] USA focuses on Vernal and Mona as potential sites for its power plant development because both sites can access Mona switching station, which provides inexpensive access to western markets with increasing demand for new power. [Ex. 70; see also Ex. 71]	

	5/7/2001	5/22/2001	5/31/2001	June 2001	6/19/2001
Panda Negotiations					Panda approaches PaC in SLC for PaC to buy power from or become equity participant in Panda Mona project. PaC response - wait for issuance of PaC's Integrated Resource Plan (IRP). [Thurgood Dep. 137-40; Barlow Dep. 98, 102-09, 115, 134; Ex. 293]
Current Creek Development					
Williams/HRO's Representation of PacifiCorp					
PacifiCorp/ USA Power Negotiations					
Williams/HRO's Representation of USA Power	Williams sends USA memo Re: "Potential Generation Sites." [Ex. 70]	USA signs Williams' retainer agreement and pays $10,000 retainer. [Ex. 23; Ted Dep. 59-60]	Williams sends USA invoice for legal services, including re: "Conf. w/ representative on Utah Lake water," and Endangered Species Act issues." [Ex. 48]	Williams meets with USA development team. [See Ted Dep. 68, 74-75, 78-79]	
[illegible] Development				USA [illegible]pment tea[illegible] [illegible]p. 68, 74-7[illegible] USA makes decision to use gas not coal, as fuel because of environmental and water issues. [Ted Dep. 109-10, 115-16, 135-37]	

plant configuration (2x1 combined cycle), turbine size and configuration (GE 7FA), base and peaking capacity (H[illegible]G duct b[illegible]rs), fuel transmission (lateral line from Questar mainlin

	6/20/2001	6/30/2001	July 2001	7/01/2001	7/10/2001
Panda Negotiations					
Current Creek Development					
Williams/HRO's Representation of PacifiCorp					
PacifiCorp/ USA Power Negotiations					
Williams/HRO's Representation of USA Power	Williams emails USA re: Potential Generation Sites, and USA's competitor Panda [Ex. 71]	Williams sends USA invoice for legal services including re: "Conf. w/ Ute Indian representative" and "Tel w/ Utah Lake water broker." [Ex. 49]	Williams meets with USA development team [See Ted Dep. 68, 74-75, 78-79]		Williams participates in USA's negotiations with Kennecott. [Ex. 73, Williams Dep. 248-52]
			de [illegible]	...ts M [illegible] ability of assets and public [illegible] 0, 50] ...tains ABB [illegible] Flaw Analysis of Transmission. [Ted Dep. 44, Ex. 10 at P84] USA retains Navigant Consulting to do analysis of markets for power. [Ted Dep. 14, 177, Ex. 10 at P19]	USA meets with Kennecott re: obtaining water right [Ex. [illegible] Will. Dep. [illegible]]

...e 104 condensor type (dry cooled). [Ted Dep. 96, 114, Ex. 10 at 11-16] ... velops site-speci... design ... Spri... USA develops site specific design for Spring Canyon Pla...

	7/31/2001	7/20/2001	Aug. 2001	8/31/2001	Sept. 2001	9/30/2001	Oct. 2001
Panda Negotiations							
Currant Creek Development							
Williams/HRO's Representation of PacifiCorp							
PacifiCorp/ USA Power Negotiations							
Williams/HRO's Representation of USA Power	Williams sends USA invoice for legal services including re: telephone calls with Dave re: "strategy." [Ex. 50]	Williams faxes USA re: USA's competitor Panda [Ex. 72; Williams Dep. 249-50]	Williams meets with USA development team. [Ted Dep. 68, 74-75]	Williams sends USA invoice for legal services including re: annexation of USA property and mtg in Nephi with Dave and Nephi City [Ex. 51]	Williams meets with USA development team [See Ted Dep. 68, 74-75, 78-79]	Williams sends USA invoice for legal services including re: annexation of USA property; "mtg w/Nephi and USA Power team"; and conference on Nephi Project [Ex. 52]	Williams meets with USA development team [See Ted Dep. 68, 74-75, 78-79]

US

nt --

Sp

Ca

De

[Ted Dep. 68, 74-75]

rights; air permit;

ps site-specific de

rezoning property for

ng Canyon Plant -- US

SA development team

[Ted Dep. 68, 74-75]

USA decides to use dry vs. wet cooling due to lack of availability/ cost of water in Juab County, and based on Waldron Engineering's cost and feasibility studies [... 10; P10; P1...; P15 ...; Ted Dep. ...]

; transmission in

site-specific desig

ction agreemen

ng Canyon Pla

USA development team mtg [Ted Dep. 68, 74-75]

10/03/2001	10/31/2001	Nov. 2001	11/31/2001	Dec. 2001	12/31/2001	Jan. 2002	1/04/2002

Panda Negotiations

Current Creek Development

Williams/HRO's Representation of PacifiCorp

PacifiCorp/ USA Power Negotiations

Williams/HRO's Representation of USA Power

- **10/03/2001:** Williams agrees to handle USA's "Public Communications/ Response" to obtain public support for Spring Canyon [Ex. 74]
- **10/31/2001:** Williams sends USA invoice for legal services including re transmission interconnection, real estate, and negotiations with Don Jones. [Ex. 53]
- **Nov. 2001:** Williams meets with USA development team [See Ted Dep 68, 74-75, 78-79]
- **11/31/2001:** Williams sends USA invoice for legal services including re zoning; annexation; option agreements; and conference with Don Jones. [Ex. 54]
- **Dec. 2001:** Williams meets with USA development team [See Ted Dep 68, 74-75, 78-79]
- **12/31/2001:** Williams sends USA invoice for legal services including re annexation, drafting water options; and negotiations with Michael Keyte for property purchase. [Ex. 55]
- **Jan. 2002:** Williams meets with USA development team [See Ted Dep 68, 74-75, 78-79]
- **1/04/2002:** Williams obtains real estate option for USA [Ex. 11 at P175; Ted Dep. 81-82]

t for Mon ... USA acquires ... vel ... -- U ... sary to develop S ... ts neces ... e

t -- USA ... cific ... e-sp ... Sprin ... anyon Plant -- USA ... Spring Ca ... a

Spring Canyon Development

- **Nov. 2001:** USA developm team m [Ted Dep. 74-75]
- **Dec. 2001:** USA development team mtg [Ted Dep. 68, 74-75]
- **Jan. 2002:** USA development team mtg. [Ted Dep. 68, 74-75]
- **1/04/2002:** USA signs ... tate Opti... Purchase Contract with Keyte for 40 acres .75 miles north of Mona Substation. [Ex. 11 at P175; Ted Dep. 81-82]

	1/31/2002	Feb. 2002	2/07/2002	2/11/2002	2/28/2002	Mar. 2002	3/31/2002	Apr. 2002
Panda Negotiations								
Current Co- Development								
Williams/HRO's Representation of PacifiCorp								
PacifiCorp/ USA Power Negotiations								
Williams/HRO's Representation of USA Power	Williams sends USA invoice for legal services, including re: purchase of Keyte property, telephone call "on County Commission"; and negotiations with Don Jones. [Ex. 56]	Williams meets with USA development team [[See Ted Dep 68, 74-75, 78-79]		Williams creates and registers Spring Canyon LLC to hold certain development assets. [Ex. 11 at P325]	Williams sends USA invoice for legal services including re: formation of Spring Canyon Energy LLC and negotiations with Don Jones. [Ex. 57]	Williams meets with USA development team [See Ted Dep 68, 74-75, 78-79]	Williams sends USA invoice for legal services including re: water appraisals and negotiations with Don Jones. [Ex. 58]	Williams meets with USA development team [Ted Dep. 68, 74-75]
velop Spring Can… nt -- … velop… …ment		…ts necessary to develop Spring Can… …g Canyon… USA development team mtg [Ted Dep. 68, 74-75]	…ant -- …A dev… …signs… …w… …um "… to Real Esta… Option and Purchase Contract with Keyte [Ex. 11 at P185]	…catio… …perm… …new… …r pla… …site… Mona. …x. 10 at P1…	…res asse…	…to develop Spring Canyon… …on Plant -- US… US… develo… team mtg [Ted Dep. 68, 74-75]	…velo… …SA acqu… …pecific…	…ts necessary to dev… …Spring Canyon Pla… …evelopment team mtg …Dep. 68, 74-75] …SA meets with Nephi Officials and begins application process to rezone property for use as industrial site [Ted Dep. 130-131]

4/01/2002	4/30/2002	May 2002	5/09/2002	5/31/2002

Panda Negotiations

Currant Creek Development

Williams/HRO's Representation of PacifiCorp

PacifiCorp/ USA Power Negotiations

Williams/HRO's Representation of USA Power

4/30/2002: Williams sends USA invoice for legal services including re: "Conf. w/ USA", formation of Spring Canyon LLC, zoning, and purchase of Keyle water. [Ex. 59]

May 2002: Williams meets with USA development team and air and environmental consultants. Williams reccomends USA hire HRO re: air permit issues. [Ted Dep. 68, 74-75, 141-42]

Williams introduces USA to Blaine Rawson at HRO to represent USA on air permit issues. [Ted Dep. 141-42]

5/31/2002: Williams sends USA invoice for legal services including re: zoning, draft water purchase options; and air permit [Ex. 60]

velop Spring ... USA acquires a...s necessary to develo... ring Canyon -- USA acquir... s nec... ary to develop Spring Canyon -- USA acquires assets necessary to deve

nt -- USA ... Sprin... nyon ... nt -- U...A develops sit... ecific des... Sprin... nyon ... lant -- USA develops site-specific design for Spring Canyon Plan

Spring Canyon Develop...

4/01/2002: Flaw Analysis ... USA's 550 MW Generating Pla... at Mona 345 k... substation. [Ex. 10 at P84]

May 2002: USA development team mtg with air and environmental consultants. [Ted Dep. 68, 74-75, 141-42]

5/09/2002: USA retains HRO to assist Williams based on Williams' recommendation. [Ex. 145A; Ted Dep. 141-42]

	June 2002	6/20/2002	6/30/2002	End of June 2002
Panda Negotiations				
Currant Creek Development				
Williams/HRO's Representation of PacifiCorp				
PacifiCorp/ USA Power Negotiations				
Williams/HRO's Representation of USA Power	Williams meets with USA development team. [See Ted Dep. 68, 74-75, 78-79]		Williams sends USA invoice for legal services including re: air permit, prepare escrow agreement; and Blake Garrett sale of water. [Ex. 144A]	Williams asks USA to move with her to HRO and USA agrees. [Ex. 28, Ted Dep. 142-43]
			ry to develop Spring C … or Spring Canyon Plant USA dev	USA acquires assets necessary to … e specific design for Spring Canyon
Can… Devel…ent	Naviqant issues …arket Assessment for Spring Canyon, concluding that, "based upon existing resources in the Utah market area and the expected load growth for the region, [PaC] should be looking for additional capacity in the Utah market and Spring Canyon would provide fuel diversity and operational flexibility for the Utah market area." [Ex. 10 at P19-…]	…AC Environmental …ultants issue expert report outlining the permit/ approval requirements to construct and operate Spring Canyon Project. [Ex. 10 at P167]		

July 2002	7/01/2002	7/05/2002	7/08/2002

Panda Negotiations

Williams/HRO's Representation of PacifiCorp

PacifiCorp/ USA Power Negotiations

Williams/HRO's Representation of USA Power

Spring Canyon Development

July 2002

Williams meets with USA development team. [See Ted Dep. 68, 74-75, 78-79]

USA development team mtg [See Ted Dep. 68, 74-75]

7/01/2002

USA acquires assets necessary to develop Spring Canyon – USA acquires ... s a

... design for Spring Canyon Plant – USA develops site spe... sign for Sp ... Spr

... zoning variance approved for industrial use of property. [... 6... 11 at P189]

Waldron Engineering issues USA its expert report on Spring Canyon performance analysis and alternative equipment configuration. [Ex. 10 at P16]

Dr. Ted Guth issues USA his expert report on USA's application for an air permit concluding that the UDAQ will issue an air permit for a 250 MW plant and USA can readily obtain the emission credits necessary to obtain an air permit for a 500 MW plant when the need arises. [Ex. 10 at P109]

Waldron Engineering issues USA its expert report on the water requirements for the proposed Spring Canyon ... at P16]

7/05/2002

HRO (Blaine Rawson) sends USA invoice for legal services including re: air permit. [Ex. 145A]

7/08/2002

Williams moves to HRO and takes USA Power and its files with her. [Ex. 28, Ted Dep. 142-43]

7/15/2002	7/31/2002	Aug. 2002	8/01/2002	8/01 - 8/22/2002

Panda Negotiations

7/31/2002: Panda calls PaC re: Status of IRP. They discuss "range of possibilities" including "PaC becoming an equity participant and PaC buying power from Panda." PaC expresses possible interest in buying Mona site, but makes no further contact until December 2002, after PaC had received USA's confidential information re: Mona. Selling assets to PaC not Panda's first choice because Panda wants to build plant. [Barlow Dep. 78, 144, 152-54; Ex. 300]

Williams/HRO's Representation of PacifiCorp

PacifiCorp/ USA Power Negotiations

8/01 - 8/22/2002: USA Calls PaC to set-up mtg. for 8/22/02 in Portland [Ted Dep. 153-60; Ex. 7]

8/01 - 8/22/2002: USA and Williams develop Vol. I of confidential information in preparation for PaC negotiations. [Ex. 10, 86, 87, 89]

8/01/2002: PaC (Thurgood) calls USA re: Spring Canyon. [Ted Dep. 153-54]

Williams/HRO's Representation of USA Power

Aug. 2002: Williams meets with USA development team [See Ted Dep 68, 74-75, 78-79]

8/01/2002: USA calls Williams re: PaC contact. [Fors Dep. 183, 192-93, 215-19; Fors Aff. Ex. 3 (801) 521-5800]

8/01 - 8/22/2002: Williams helps USA prepare "Marketing Book" for negotiations w/ PaC. Williams understands book will be used to facilitate sale of Spring Canyon. [Ex. 10, 86, 87, 89; Williams Dep. 268]

Spring Canyon Development

...assets necessary ...nyon USA acquires assets necessary to develop Spring Canyon

...ing Canyon Plant ...specific design for Spring Canyon Plant

7/15/2002: ...lls PaC ...transmission for ...erconnection with Mona substation. [...7/8/02 Qwest bill for (970) 871-6223]

USA acquires assets necessary to develop Spring Canyon ...acqui...

Aug. 2002: USA development team mtg. [See Ted Dep. 74-75]

	8/05/2002	8/08, 8/12, 8/14/2002	8/14/2002	8/15/2002	8/16/2002	8/20-8/21/2002	8/22 or 8/23/2002
Panda Negotiations							
Currant Creek Development							
Williams/HRO's Representation of PacifiCorp							
PacifiCorp/ USA Power Negotiations					USA calls PaC. [Lois Aff. Ex. 3 - (503)-813-5380]		USA meets with PaC in Portland (approx. 2 hrs). USA refuses to give confidential information to PaC without non-disclosure agreement. Parties agree to meet again on 9/11/02. [Ted Dep. 155-62; Lois Dep. 219-21, 236; Ex. 7]
Williams/HRO's Representation of USA Power	USA calls Williams. [Lois Aff. Ex. 3, (801) 521-5800] HRO sends USA invoice for legal services. [Ex. 146A]	USA calls Williams. [Lois Aff. Ex. 3 (801) 521-5800]			USA calls Williams. [Lois Aff. Ex. 3 - (801) 521-5800] Williams sends USA invoice for legal services, including re USA's marketing book and escrow. [Ex. 86]	USA meets with and calls Williams re: upcoming PaC negotiations. [Lois Dep. 180-86; Lois Aff. Ex. 3 (801) 521-5800]	
Spring Canyon Development	USA signs Water Right Option & Purchase Agreement with Garrett ($4,000 per af [Ex. 11 at ...]		USA signs Water Right Option & Purchase Agreement with Keyle ($4,000 per af) [Ex. 11 at P2...]	UDAQ issues USA NOI for 250 MW plant on its Mona site [Ex. 7 at p.279, Ted Dep. 144-49]			

...es assets necessary to develop Spring Canyon USA acquires assets necessary to develop Spring Canyon USA acquires assets necessary to develop Spring Canyon USA acquire...

	8/26/2002	8/27/2002	8/30/2002	Sept. 2002	9/03/2002	9/04/2002	9/05/2002	9/06/2002
Panda Negotiations								
Williams/HRO's Representation of PacifiCorp				USA and Williams prepare 2nd binder of confidential information to be used in negotiations w/PaC. [Ex. 11 at 86, 87, 89; Ted Dep. 182-84]				
PacifiCorp/ USA Power Negotiations						USA calls PaC. [Lois Aff. Ex. 4 - (801)-220-4807]		USA calls PaC. [Lois Aff. Ex. 4 - (801)-521-5800]
Williams/HRO's Representation of USA Power	USA calls Williams [Lois Aff. Ex. 3 (801) 521 5800]	USA meets with and calls Williams re: PaC negotiations, including confidentiality agreement. Williams agrees to call PaC and "Say kind things" about USA. [Ex. 99, Ted Dep. 162-165, Lois Dep. 236-37]	USA calls Williams. [Lois Aff. Ex. 4]	Williams helps USA prepare 2nd marketing book to be used in negotiations w/PaC. [Ex. 11, 86, 87, 89, Ted Dep. 182-84] Williams meets with USA development team [See Ted Dep. 68, 74-75, 78-79]	USA calls Williams. [Lois Aff. Ex. 4 - (801) 521-5800]		USA calls Williams. [Lois Aff. Ex. 4 (801) 521 5800]	
Development			USA calls PaC transmission re: interconnection at Mona substation. [Lois Aff. Ex. 4 - (801) 521-5800]	USA development team mtg [See Ted Dep				

...necessary to develop Spring... es assets necessary to develop Spring Canyon -- USA acquires assets necessary to develop Spring Canyon -- USA acquire

	9/09/2002	9/10/2002	9/11/2002	9/12/2002
Panda Negotiations				
Currant Creek Development				
Williams/HRO's Representation of PacifiCorp		USA memo to PaC re: 9/11/02 mtg in SLC. [Ex. 8]		
PacifiCorp/ USA Power Negotiations			USA meets in SLC with PaC. [Ted Dep. 165-96; Lois Dep. 221-30] • PaC signs Confidentiality Agreement. [Ex. 9] • USA gives PaC 2 volumes of confidential information. [Exs. 10, 11; see Ex. 20] • PaC admits it has never considered Mona as a site. [Ted Dep. 188-90] • PaC admits USA has advantage of 2-3 years and several million dollars over PaC. [Ted Dep. 190] • PaC says it is skeptical of dry-cooling, especially in Mona. [Ted Dep. 187-90]	
Williams/HRO's Representation of USA Power	USA calls Williams. [Lois Aff. Ex. 4 (801) 521-5800]	USA meets with and calls Williams re: negotiations with PaC [Ted Dep. 168-69; Lois Aff. Ex. 4 (801) 521-5800] HRO sends USA invoice for legal services. [Ex. 147A]	USA meets with and calls Williams before and after its mtg with PaC [Ted Dep. 199-202; Lois Dep. 161-66, 169-70; Lois Aff. Ex. 4 (801) 521-5800]	USA meets with and calls Williams re PaC negotiations. [Lois Dep. 191, 194; Lois Aff. Ex. 4 (801) 521-5800] Williams attends USA's negotiations with UAMP. [Ted Dep. 214-15; Lois Dep. 172-73] Williams notes: "If interested sign Confidentiality Agmt." [Ex. 88]
Spring Canyon Development	USA obtains Letter of Intent from Questar to provide natural gas transportation lateral line to Spring Canyon. [Ex. 11 at P313]	USA files application with FERC for determination Spring Canyon is EWG - Exempt Wholesale Generator status. [Ex. 11 at P...]		USA signs PaC Letter of Intent for Interconnect Agreement at Mona substation. [Ex. 11 at P308-310; Ted Dep. 117-22]

USA acquires assets necessary to develop Spring Canyon

	9/16/2002	9/19/2002	9/23, 9/25, & 9/27/2002	Late Sept./ Early Oct. 2002	Oct. 2002	10/01 - 10/8/2002	10/10/2002	10/11/2002
Panda Negotiations								
[illegible] Development								
Williams/HRO's Representation of PacifiCorp								
PacifiCorp/ USA Power Negotiations				PaC calls USA and requests firm offer for purchase of power from Spring Canyon. [Ted Dep. 202-10]				USA ltr to PaC with offer as requested by PaC. [Ex. 115; Ted Dep. 204-08] USA calls PaC. PaC expresses skepticism of dry-cooling. [Lois Aff. Ex. 5 - (801)-220-4648; Ted Dep. 215-17]
Williams/HRO's Representation of USA Power	USA calls Williams. [Lois Aff. Ex. 4 (801) 521-5800]	Williams sends USA invoice for legal services including re marketing issues, air issues, and zoning. [Ex. 87]	USA calls Williams. [Lois Aff. Ex. 4 (801) 521-5800]		Williams meets with USA development team [See Ted Dep. 68, 74-75, 78-79]	USA calls Williams. [Lois Aff. Ex. 4 (801) 521-5800]	Williams sends USA invoice for legal services including re marketing, Keyte change application; and negotiations w/ UAMPS. [Ex. 89]	
Spring Canyon Development					USA development team mtg [See Ted Dep. 68, 74-75, 78-79]		UDAQ issues USA draft plan review with Recommended Approval Order for 280 MW plant at its Mona site [Ex. 11 at P2?; Ted Dep. 141-49]	

assets necessary to develop Spring Canyon -- USA acquires assets necessary to develop Spring Canyon -- USA acquires assets necessary to develop Spring Canyon -- USA acquires

Panda Negotiations

Current Creek Development

Williams/HRO's Representation of PacifiCorp

	10/15/2002	10/23/2002	10/24/2002	10/29/2002	Nov. 2002	11/06/2002	11/11/2002	11/12/2002
PacifiCorp/ USA Power Negotiations	USA meets in Portland with PaC. [Ted Dep. 208-11] PaC requests USA send option agreement for asset purchase. [Ted Dep. 204-11]	USA ltr to PaC with draft option agreement. [Ex. 13; Ted Dep. 211-13] USA calls PaC. PaC expresses skepticism of dry-cooling. [Lois Aff. Ex. 5 - (801)-220-4648; Ted Dep. 215-17]		USA obtains ltr from Waldron Engineering verifying its decision to use dry-cooling in response to PaC's dry-cooling concerns. (Ltr. sent to PaC 11/26/02) [See Ex. 15; Ted Dep. 215-16, 229-40] USA calls PaC. [Lois Aff. Ex. 5 - (801)-220-4807]	USA calls PaC re: asset purchase agreement. [Ted Dep. 215] PaC again tells USA that PaC is skeptical of dry-cooling because of loss of efficiency. [Ex. 14; Ted Dep. 215-16, 229-30, 241-42]		USA calls PaC. [Lois Aff. Ex. 6 - (801)-220-4807]	
Williams/HRO's Representation of USA Power			USA calls Williams. [Lois Aff. Ex. 5 - (801) 521-5800]		Williams meets with USA development team. [See Ted Dep. 68, 74-75, 78-79]	Williams sends USA invoice for legal services including re conferences with Ted & Lois. [Ex. 90]		
	USA acquires assets necessary to develop Spring Canyon							
					USA development team mtg. [See Ted Dep. 68, 74-75, 78-79]			USA calls PaC transmission re interconnection to Mona substation. [Lois Aff. Ex. 6 - (801)-220-4807]

- Panda Negotiations
- Garrett Creek Development
- Williams/HRO's Representation of PacifiCorp

	11/20/2002	11/26/2002	11/27/2002	Dec. 2002	12/11/2002	12/12/2002	12/13/2002
PacifiCorp/ USA Power Negotiations	USA calls PaC. [Lois Aff. Ex. 6 - (503)-813-5351 & (801)-220-4807]	USA ltr to PaC: • Enclosing revised option agreement. [Ex. 14; Ted Dep. 226-42] • Enclosing Waldron Engineering's ltr demonstrating feasibility of dry-cooling to address PaC's concerns. [Exs. 14, 15; Ted Dep. 226-42] USA calls PaC. [Lois Aff. Ex. 6 - (801)-220-4648]				USA calls PaC. [Ex. 246 - (801)-220-4807]	
Williams/HRO's Representation of USA Power	USA calls Williams. [Lois Aff. Ex. 6 - (801) 521-5800]		USA calls Williams. [Lois Aff. Ex. 6 - (801) 521-5800]	Williams meets with USA development team [See Ted Dep. 68, 74-75, 78-79]	Williams sends USA invoice for legal services. [Ex. 91]	USA calls Williams. [Lois Aff. Ex. 6 - (801) 521-5800]	
Spring Canyon Development			USA obtains UDAQ Approval Order for Spring Canyon Air Permit. [Ex. 16 at P1100, Ex. 168; Ted Dep ...]	USA development team mtg [See Ted Dep. 68, 74-75, 78-79]			Utah Division of Water Rights approves Change Application for USA water rights purchased from Garrett. [Ex. 16 at P1112-15; Lois Dep. 159]

...assets necessary to develop Spring Canyon — USA acquires assets necessary to develop Spring Canyon — USA acquires assets necessary to develop Spring Canyon — USA acquires...

	12/23/2002	Late Dec. 2002	Late 2002 - Early 2003	Jan. 2003	1/09/2003
Panda Negotiations		Panda tells PaC for first time Panda has interest in selling the assets of its Mona project. [Barlow Dep. 186-87; Ex. 300]			PaC discusses all options to meet 2005 & 2007 power needs - Panda **never** mentioned. [Ex. 354]
Current Coal Development					PaC discusses options to meet 2005 peaking need & 2007 base load need. **No** mention of Panda - Spring Canyon only option to meet 2005 peaking need. Only other recommendation is Gadsby repowering and building Hunter 4. [Ex. 354]
Williams/HRO's Representation of PacifiCorp					
PacifiCorp/ USA Power Negotiations				PaC issues IRP confirming need to develop new generation capability to meet Utah customers' needs beginning 2005 and mentions Mona Location. PaC files IRP with Utah Public Service Commission (PSC). [Exs. 1, 2]	PaC memo re: meeting future generation requirements. PaC concludes only USA can meet 2005 demand and recommends buying Spring Canyon for up to $5 million. [Ex. 354 at 3]
Williams/HRO's Representation of USA Power	USA calls Williams. [Lor. Aff. Ex. 6, (801) 521-5800]			Williams meets with USA development team. [See Ted Dep. 68, 74-75, 78-79]	USA calls Williams & Vuyovich (HRO). [Exs. 247, 251 (801) 521-5800, Lor. Dep. 148-51]
Spring Canyon Development			USA prepares Vol. III of Confidential Information which includes its detailed economic proforma projections it developed over 2 years, which demonstrate Spring Canyon is economically viable. [Ex. 16; Ted Dep. 248-49; Lor. Dep. 299-300]	USA development team mtg [See Ted Dep. 68, 74-75, 78-79]	

ssets necessary to develop Spring Canyon - USA acquires assets necessary to develop Spring Canyon - USA acquires assets necessary to develop Spring Canyon - USA acquires as

	1/13/2003	1/14/2003	1/16/2003	1/22/2003	1/27/2003
Panda Negotiations		PaC's first negotiations with Panda to purchase Panda's site in Mona. [Ex. 304; Barlow Dep. 154, 156-57, 185-86; Thurgood Dep. 137-40]	Panda, at PaC's request, provides PaC with "confidential information regarding the project details" and "a summary of the work completed." Panda claims to have spent $964,818 on its site development; its only assets are 2 land options and studies and reports primarily relating to air monitoring (met data) - nothing regarding air vs. water cooling. [Ex. 304]		
[illegible]					
Williams/HRO's Representation of PacifiCorp					PaC contacts Williams/HRO re: acquiring water in Elberta - a location near the Mona substation. [PAC025267; see Williams Dep. 208] Williams never advises USA or seeks its consent. [Ted Dep. 410-11; Williams Dep. 233]
PacifiCorp/ USA Power Negotiations	USA calls PaC. [Ex. 251 - (801)-220-4807]	USA calls PaC (44 min). [Ex. 247 - (801)-220-4807]			
Williams/HRO's Representation of USA Power	Williams sends USA invoice for legal services including re: researching Don Jones' water rights. [Ex. 92]				
Spring Canyon Development	...ets necessary to develop Spri[illegible] Canyon -- USA acquires assets necessary to develop Spring Canyon --		USA calls PaC transmission. [Ex. 247 - [illegible]]	Utah Division of Water Rights approves Change Application for USA water rights purchased from Keyte. [illegible]	

	1/31/2003	2/02/2003	2/05/2003	2/10/2003	2/11/2003	2/18/2003
Panda Negotiations	PaC sends letter of intent to Panda. [Ex. 301] The only assets PaC purchases are: (1) Real Estate Purchase Options, and (2) Reports and Studies, none of which relate to wet vs. dry cooling or plant design and none of which PaC considers material except relating to met data. [Exs. 301-02; Barlow Dep. 155-58; Thurgood Dep. [illegible]]	Williams discusses potential water sellers w/ PaC. [illegible]	PaC authorizes purchase of Panda project <u>solely</u> for future options (2006 or later) and to assist in negotiations with USA. [Ex. 355; Ted Dep. 339-40]			
Currant Creek Development		Williams only specifically mentions sellers she had contacted for USA. [illegible]	PaC authorizes acquisition of Spring Canyon as the necessary basis for developing its own power plant in Mona Currant Creek because Spring Canyon is the "only viable project site capable of meeting 2005's demand." [Ex. 355 at 6, 8]			
Williams/HRO's Representation of PacifiCorp		Williams quotes $4,000 as probable price for water right, the exact price USA confidentially paid for its water rights. [illegible]				USA meets with PaC in SLC. [Ted Dep. 249-57, 261-78; Lois Dep. 238-44, 269]
PacifiCorp/USA Power Negotiations			PaC authorizes purchase of Spring Canyon for $3.5 million. [Ex. 355 at 3, 5, 8]	USA calls PaC. [Ex. 248 - (801)-220-4807]		• USA delivers Vol. 3 of confidential information to PaC. [Ex. 16, Tomsic Aff. 3A, Ex. 8] • PaC verbally offers $5 million for Spring Canyon assets. [See Tomsic Aff. 3A, Ex. 8; Ted Dep. 249-53]
Williams/HRO's Representation of USA Power					Williams sends USA invoice for legal services. [Ex. 94]	
Spring Canyon Development						

2/20/2003	2/24/2003	2/27/2003	3/02/2003	3/04/2003	3/07/2003

Panda Negotiations

Currant Creek Development

Williams/HRO's Representation of PacifiCorp

PacifiCorp/ USA Power Negotiations

Williams/HRO's Representation of USA Power

Spring Canyon Development

2/20/2003

PaC concludes it should "stress dry-cooling experience" when finding an engineer for Currant Creek [Ex. [illegible]] PaC would not internally "research" or formally "decide" to use dry cooling until 05/16/03 [See [illegible] 371, 374]

2/24/2003

PaC closes Panda Purchase. [Thurgood Dep. 142; Ex 302]

USA calls PaC. [Ex. 248 - (503)-813-5851]

2/27/2003

PaC compares USA's work with PaC's work and concludes, "we seem to be behind." [Ex. 391]

PaC's internal notes reference Williams/ HRO. [PAC025304 to 06]

PaC sends $2 million written offer to USA for Spring Canyon. [Ex. 17; Lois Dep. 265-67; Ted Dep. 278-83]

USA calls PaC transmission [Ex. 248 - (503)-813-5735]

3/02/2003

Williams officially begins representing PaC relative to its competing Currant Creek project in Mona [Ex. 66].

Williams never advises USA or seeks its consent. [Ex. 66; Williams Dep. 233]

Williams knows USA negotiating w/ PaC. [See e.g., Ted Dep. 157-58, 162-65]

3/04/2003

Williams meets w/ PaC re: RFP, etc. [PAC025309]

3/07/2003

USA sends $6.5 million counter-offer to PaC. [Lois Dep. 266-67; Ex. 18; Ted Dep. 282-86]

	3/10/2003	3/11/2003	3/12/2003	03/14/2003	3/17/2003	3/17 - 3/18/2003
Currant Creek Development						
Williams/HRO's Representation of PacifiCorp						
PacifiCorp/ USA Power Negotiations	USA calls PaC re: counter-offer and compromise. [See Ted Dep. 285-86]	USA emails PaC confirming PaC's $3 million offer and counters with $5 million offer. [Lois Dep. 266-72; Ex. 165]		USA and PaC agree PaC will purchase Spring Canyon for $3 million and enter into Joint Development Agreement with USA. [Ted Dep. 286-90; Lois Dep. 142-43, 245-49, Exs. 19, 249 - (801)-220-4807]	USA principals travel to Portland to close deal w/ PaC. [Lois Dep. 245-46, 280]	PaC calls USA after USA principals arrive in Portland and declares deal is off for PaC's own business reasons and PaC will issue RFP. [Ted Dep. 286-96; Lois Dep. 245-47, 280, 392-93] Ted calls Dave from Portland to advise of PaC's decision (64 min). [Ex. 252 - (214)-520-8177]
Williams/HRO's Representation of USA Power			Williams sends USA invoice for legal services. Williams does not terminate representation or return files. USA continues to believe Williams is its lawyer. [Ex. 94; Lois Aff. ¶ 38]			
Spring Canyon Development						

Currant Creek Development

Williams/HRO's Representation of PacifiCorp

PacifiCorp/ USA Power Negotiations

Williams/HRO's Representation of USA Power

Spring Canyon Development

3/19/2003

USA calls PaC. [Ex. 252; (801)-220-4807]

PaC returns USA's call assuring USA the RFP is "yours to lose." [Ted Dep. 292-96; Lois Dep. 280-83]

3/20/2003

PaC emails USA confirming both $3 million asset purchase and Joint Development Agreement are cancelled. [Ex. 19; Ted Dep. 296-98]

3/21/2003

Williams participates in negotiations between PaC and Kennecott even though she had previously attended and represented USA during its negotiations w/Kennecott. [Compare Ex. 66; Williams Dep. 192-93 with Ex. 73; Williams Dep. 250]

Ted calls Williams and informs her that PaC has called off the deal and PaC is going to issue RFP. USA specifically asks Williams for advice about project and how to move forward. Williams does not terminate representation or return files. USA continues to believe Williams is its lawyer. [Ted Dep. 308-10; Lois Aff. ¶[illegible]]

RFP -- RFP -- RFP -- RFP -- RFP -- RFP -- RFP -- RFP -- RFP -- RFP -- RFP -- RFP -- RFP -- RFP -- RFP -- RFP -- RFP -- RFP

USA decides to pursue RFP because it is the only entity that has already developed a site at Mona to meet PaC's 2005 demand. [Kelteck Rpt. at 18; Ted Dep. 180-82, 215-16 see also Ex. 117 at P1304; Olive Rpt. 5-7 (Ex. 433); Malko Rpt. at 14-15, 18, 24 (Ex. 419)]

USA attends PaC's RFP pre-bid conference in Portland. [Ex. 116]

- PaC claims all bids to be submitted under strict confidentiality.
- PaC affiliates could not bid.
- PaC will submit "virtual bid" to compare against bids. [Ted Dep. 300-10]

3/26/2003

USA requests PaC return USA's confidential info. [Ex. 254]

PaC only returns volume 1, [Ex. 10] claiming other 2 volumes destroyed. [Ted Dep. 292-96; Lois Dep. 280-83]

4/01/2003

Williams approves/ drafts PaC memo seeking authorization to spend $16.2 million to acquire water rights for Currant Creek claiming no other RFP bidder will have water rights, even though she knows USA does. [See e.g., Ex. 31, 68 at p. 7; Williams Dep. 216]

	4/08/2003	4/09/2003	4/10/2003	4/17/2003	4/22/2003	4/24/2003
Currant Creek Development		PaC authorizes expenditure of up to $16.2 million for purchase of water rights for Currant Creek. [illegible]		PaC interviews engineers for a project in Mona (Currant Creek), shortly thereafter selects Stone & Webster. [Hungood dep. [illegible]; Ex. 364]		Hungood tells his development team for "Mona Project" that "we need a very clear trail of how we arrived at the Mona site." [illegible] Stone & Webster meet with PaC's development team. A task list is passed out at that time "as a first attempt to bring organization" to the project. [illegible] PaC had not (1) performed any on site modeling or testing at Mona (2) calculated the "energy penalty" for a dry cooled plant in Mona (3) performed a water balance study [Andrews Dep. 116; [illegible] Hungood [illegible] Van Engelen [illegible]]
Williams/HRO's Representation of PacifiCorp	Williams/HRO send PaC invoice for legal services, including re: mtg w/Rand & Jenkins and obtaining water. [Ex. 31]				Williams meets w/PaC re: Currant Creek. [Ex. 101]	
Williams/HRO's Representation of USA Power	Williams sends USA invoice for legal services. [Ex. 95]					
[illegible] Development	USA negotiates w/EIF to provide equity financing and QUIXX to construct a plant at its Mona site in connection w/RFP. [Ted Dep. 308-14]		USA files amended application for air permit for 500 MW plant at its Mona site and will acquire air credits when required. [Ex. 117 at P1577]			

RFP -- RFP

	May 2003	5/07/2003	5/12/2003	5/16/2003	5/19/2003	5/21/2003	5/30/2003
[illegible]		PaC requests Burns & McDonnell, an engineering firm, do an "independent evaluation" of wet vs. dry cooling and related performance at the Mona site. [illegible] No evidence Burns performed any such evaluation		PaC "formally" decides to use dry cooling 3 months after PaC stressed the need to find an engineer with "dry cooling experience." [illegible]			
Williams/HRO's Representation of PacifiCorp		Williams sends PaC invoice for legal services, including re: mtg with Kennecott re: water. [Ex. 32]	Williams suggests PaC "Drill @ Mona use Utah Lake Water Rights," an issue Williams had previously researched for USA Power. [Compare Tomsic Aff. 3A, Ex. 8, PAC025412 with Ex. 49]		Williams meets w/PaC re: Michael Keyte even though Williams had previously represented USA in the confidential purchase of Mr. Keyte's water. [Compare Ex. 100 with Ex. 55-60, Ex. 11 at P235]	HRO attorney reviews "change application filed in Mona area." He can't remember any application besides USA's. [Ex. 33; Vuyovich Dep. 47-50]	Williams negotiates w/ Noreen Harper re: water rights for Currant Creek and prepares draft option agreement, even though Williams had previously negotiated w/Harper on USA's behalf. [Compare Exs. 33-34 with Ex. 75]
Williams/HRO's Representation of USA Power		Williams sends USA invoice for legal services. [Ex. 96]					
RFP -- RI							
Spring Canyon Development	EIF and QUIXX decide to participate with USA in seeking PPA with PaC through RFP process. [Ted Dep. 311-14]						

	6/02/2003	6/06/2003	6/09/2003	6/11/2003	6/13/2003	6/20/2003	7/14/2003	7/18/2003
Currant Creek Development			Stone & Webster submits project cost analysis for Currant Creek [PaC Memo in Support of Summary Judgment ¶ [illegible]]	PaC Notes: "USA Power on Questar - How Do They Pay Call Lynn." [illegible]		Stone & Webster performs PaC's first site specific performance evaluations for dry cooling and the proposed Currant Creek plant." [illegible]		
Williams/HRO's Representation of PacifiCorp	Williams negotiates w/Don Jones re: water for Currant Creek, even though she had previously negotiated w/ Jones on USA's behalf. [Compare Exs. 34, 39, 41, 105 with Exs. 53-54, 56-58, 75]				Williams sends PaC invoice for legal services including mtg re: "Mona Plant" and Kennecott water. [Ex. 33]		Williams sends PaC invoice for legal services including re: Don Jones; Noreen Harper; and "Currant Creek Power Plant." [Ex. 34]	
Williams/HRO's Representation of USA Power				Williams sends USA invoice for legal services. [Ex. 97]			Williams sends USA invoice for legal services. [Ex. 98]	
RFP -- RFP -- RFP -- RFP -- RFP								
Spring Canyon Development		PaC issues RFP requiring bids to be submitted by 7/22/03; no indication PaC going to bid on RFP; Pac represents all bids will be kept confidential. [Ex. 5; Ted Dep. 321]						USA Submits 4 confidential bids based on Spring Canyon in response to RFP. EIF/ QUIXX active in preparing bids. [Ex. 117; Ted Dep. 328-33]

Row labels (left side of chart): Currant Creek Development; Williams/HRO's Representation of PacifiCorp; Williams/HRO's Representation of USA Power; Spring Canyon Development

RFP .. RFP

7/22/2003

PaC submits its NBA. All RFP bids are locked down. [Ex. [illegible]; Ted Dep. [illegible]]

PaC returns USA's confidential Vol. 2 [illegible] to USA. [Ex. 20; Ted Dep. [illegible]] PaC never returns USA's confidential Vol. 3. [Ted Dep. [illegible]]

• Lock Down Date for RFP

7/25/2003

USA sends Williams copy of USA's extension of option on Keyle's and Garrett's water rights pursuant to contract terms. [Ex. [illegible]; Ex. 11 at P245, P267]

Aug. 2003

PaC submits application for air permit using Panda met data. [Ted Dep. [illegible]]

PaC begins detailed design for Currant Creek – even though RFP still in process. [Thompson Dep. [illegible]]

USA learns for first time PaC considering its own NBA in determining RFP winner. [Ted Dep. 337-43]

8/04/2003

USA sends Williams copy of USA's extension on Keyles real property and Garrett's water rights, pursuant to contract terms. [Ex. [illegible]; Ex. 11 at P267]

8/07/2003

Williams sends PaC invoice for legal services including re: "Mona Power Project" and "Gas turbine project near Mona, Utah." [Ex. 35]

8/22 - 8/23/2003

PaC notifies USA that USA's two most expensive bids are on RFP short list. [Ted Dep. 334-39]

8/26/2003

USA expresses concern to PaC "over Rand being in on analysis since [PaC] project is competing." [PAC025543]

Currant Creek Development

Williams/HRO's Representation of PacifiCorp

Williams/HRO's Representation of USA Power

RFP .. RFP .. RFP .. RFP .. RFP .. RFP ..

Spring Canyon Development

8/26/2003

USA executes Participation Agreement w/ QUIXX and EIF. [Ex. 421]

USA executes Loan Agreement w/ QUIXX. [Ex. 434]

9/02/2003

PaC signs agreement to acquire water rights. [Memo in Supp. Loyalty ¶ 50]

9/08/2003

Williams sends PaC invoice for legal services including re: Mona Project; conferences, and change application. [Ex. 36]

9/10/2003

Williams talks w/ Dave for 30 min re: obtaining air credits for Spring Canyon's amended air permit. [Ex. 69]

Williams understood she was acting as USA's attorney [Williams Dep. [illegible]]

USA seeks Williams/HRO's assistance in acquiring air credits for Spring Canyon [Ex. 69]

9/17/2003

HRO attorney researches air credits for Spring Canyon [Ex. 69]

9/22/2003

PaC awards the RFP to itself for Currant Creek. PaC emphasizes, issuing RFP will keep PSC from scrutinizing PaC's construction costs. [illegible]

PaC does not disclose its decision to USA or other bidders. [illegible]

PaC notes: "USA Power has not contacted Questar." [illegible]

9/24/2003

Wangsgard emails Riley re: PaC's water. "Jody single handedly" obtained the necessary approval. Doing so "would not have been possible without her." [Ex. 107]

9/25/2003

Bill White emails Jody/PaC. Jody "saved the day," because she obtained the approval necessary for PaC's water. [Ex. 108]

PaC requires USA to sign waiver of claims before PaC will negotiate w/USA on 2 short-listed bids; PaC does not disclose it has already awarded itself the RFP. [Ex. 164]

	9/30/2003	10/06/2003	10/16/2003	11/03/2003	11/04 -11/06/2003
Currant Creek Development		PaC signs amendment to water rights acquisition agreement [Element Supp. Loyalty ¶ 50]		PaC files application for Certificate of Convenience and Necessity (CC&N) with Utah Public Service Commission (PSC) [illegible]	
Williams/HRO's Representation of PacifiCorp		Williams sends PaC invoice for legal services. [Ex. 37]			USA learns Williams disclosing USA's confidential information to benefit PaC. [Ted Dep. 351-53; Lois Dep. 195-97]
Williams/HRO's Representation of USA Power		Williams sends USA invoice for legal services. [Ex. 69]			USA learns Williams is representing PaC in public mtgs re: opposition to PaC water purchase. USA finds articles saying Williams is PaC's attorney. [Ted Dep. 355-56; see e.g., HRO Pt 001223 to 1224]

RFP .. RFP .. RFP .. RFP .. RFP .. RFP .. RFP .. RFP .. RFP .. RFP .. RFP .. RFP .. RFP .. RFP .. RFP .. RFP .. RFP .. RFP .. RFP .. RFP ..

	9/30/2003	10/06/2003	10/16/2003	11/03/2003	11/04 -11/06/2003
Spring Canyon Development	USA signs PaC waiver. [Ex. 164]		USA and EIF meet w/PaC in Portland to negotiate PPA under RFP. [Ex. 21] PaC tells USA earliest PaC would make decision is 1/04. [Ted Dep. 343-51; Lois Dep. 260-63] EIF offers to sell plant to PaC for $1 at end of 20 yr PPA contract. PaC agrees to binding letter of intent w/USA for bid so USA can release work and equipment orders.	USA learns PaC has awarded itself the RFP and filed an application for CC&N w/ PSC. [Ted Dep. 347-53]	

	11/06/2003	11/07/2003	Nov. 2003	12/04/2003	12/05/2003	12/08/2003	12/18/2003
Currant Creek Development			Thurgood files Prefiled testimony in CC&N proceeding [Ex. [illegible]; Ted Dep. [illegible]]	PaC files timeline in CC&N proceeding [Ex. [illegible]]			When confronted by USA, Thurgood admits "we learned some things from you guys." When further confronted with USA's accusation that Currant Creek was a "clone" of Spring Canyon, Thurgood admits "we learned a lot from you guys." Thurgood also admits he would be fired if Currant Creek was not built [Ted Dep. [illegible]]
Williams/HRO's Representation of PacifiCorp			Williams/HRO learn USA has filed objection to Currant Creek's CC&N proceedings, but continues to represent PaC. [Vuyovich Dep. 63-64; <u>see</u> Ted Dep. 367-80]		HRO sends PaC invoic for legal services including r Mona EPC contract. [Ex. 150A]	Williams sends invoice to PaC for legal services including re: Mona protests; water rights; and mtgs with "Mona Town." [Ex. 39]	
Williams/HRO's Representation of USA Power	USA emails Williams re: conflict of interest in representing PaC on Currant Creek; asks her to call back. Williams never responds. [Ex. [illegible]; Ted Dep. [illegible]]	PaC notes: "Jodi Williams." "Spring Canyon really MAD work for competitor." [illegible]					
Spring Canyon Development			**USA objects to PaC's application for CC&N.** [Ted Dep. 367-80]				PaC admits to USA at SLC mtg that "we learned a lot from you guys," when confronted with Ted's accusation that Currant Creek was a "clone" of Spring Canyon. [Ted Dep. [illegible]]

	Early 2004	1/15/2004	1/21/2004	2/03/2004	2/13/2004	3/10/2004	3/14/2004
Currant Creek Development	Ian Andrews (PaC Resource Development team) makes first visit to Mona, Utah. [illegible]			PaC's Currant Creek water change application approved [illegible]			
Williams/HRO's Representation of PacifiCorp		Williams sends invoice to PaC for legal services including re: Mona hearings[illegible] water rights; an[illegible] calls to Deseret News reporter. [Ex. 40]	Williams prepares PaC's responses to USA's objections filed in PSC hearings re: granting PaC a CC&N. [Ex. 41, 111; Jody Dep. 290-91]		Williams sends invoice to PaC for legal services including re: offers to settle and water rights. [Ex. 41] Williams attends mtg re: Currant Creek. [Ex. 41] PaC admits <u>no</u> plans to do 2nd plant at Mona. [Ex. 61]	Williams sends PaC invoice for legal services. [Ex. 42]	Williams sends PaC invoice for legal services. [Ex. 45]
Williams/HRO's Representation of USA Power							
Spring Canyon Development							

	4/26/2004	5/05/2004	1/18/2005	1/18/2005	10/21/2005
Currant Creek Development	PaC closes on agreement to use water rights at Currant Creek [Memo in Supp. Loyalty ¶ [illegible]]	PSC awards PaC CCN for Currant Creek [Ex. [illegible]]			
Williams/HRO's Representation of PacifiCorp	Williams sends PaC invoice for legal services. [Ex. 45]				
Williams/HRO's Representation of USA Power			USA requests Williams return all of its files. Wiliams does not do so until after USA files this action [[illegible] Aff. ¶ [illegible]]	USA files Complaint against Williams/HRO in Third District Court of Salt Lake County, seeking recovery for Williams/HRO's breach of their fiduciary duties of loyalty and confidentiality.	USA amends Complaint to add PaC as defendant, and seeks recovery for, *inter alia*, misappropriation of USA's trade secrets.
Spring Canyon Development					

	For Approval
X	For Information
X	For Discussion

Performance CEC Meeting **January 9, 2003** **CEC014/03**

Title: **Meeting East Side IRP Thermal Generation Requirements**

Decision(s) Requested: For Noting

Executive Summary:

1) **New Thermal IRP Requirements CY2005 - CY2007**
2) **New Generation Alternatives**
3) **Recommended Action To Keep Alternatives Viable**

Key Issue(s) for Discussion: For informational purposes

Sponsor: Barry Cunningham
Senior Vice President

EXHIBIT 354
WIT: R Thurgood
DATE. 9/28/06
CitiCourt, LLC

CONFIDENTIAL

PAC022559

1039

EXECUTIVE SUMMARY

PacifiCorp's IRP will be filed within the next few weeks. It calls for 1000 MW of new peaking capacity and 2000 MW of new base-load capacity in the eastern side of PacifiCorp over the next 10 years. While these requirements are extensive and capital intensive, perhaps the single most challenging aspect of the IRP, is the time frame in which the initial resources are needed. The IRP requires 200 MW of new peaking capacity in calendar year 2005 and 500 MW of new base-loaded generation in 2007. This paper addresses issues and challenges PacifiCorp faces in meeting these requirements and how they and related concerns might best be met.

MEETING IRP REQUIREMENTS

There are essentially three ways to meet the 2005 and 2007 requirements (over and above planned DSM and renewable purchases) – through contract purchases, acquisition of existing plants, or building new facilities. Each of these solutions is faced with difficulties. For the most part, contract purchases must come from outside the Utah bubble. The already full transmission paths into the bubble will limit if not prohibit purchases sufficient to meet the additional requirements. Planned transmission upgrades and those suggested by the IRP will help but not solve this problem within the required time frames. Acquisition of existing or essentially completed power plants in areas surrounding the Utah bubble would also be faced with the same transmission constraints. Finally two major issues confront us in building either new peaking or base-load capacity. First, we have not yet reached settlement or agreement on MSP to ensure cost recovery of invested capital. Second physical project schedules (design, engineering, permitting and construction) are extremely tight even if project approvals were given today.

How then can the IRP for the East Side, new thermal resource requirements be met? The remainder of this paper identifies the real alternatives PacifiCorp now has (independent of purchases), initial economics associated with each, and a recommended approach to pursuing the most promising solutions.

REAL RESOURCE ALTERNATIVES

Real alternatives available to us today consist of acquiring existing facilities or building new ones. Each will be briefly discussed.

Plant Acquisitions

Within the Utah "bubble" it may be possible to buy back the Deseret portion of the Hunter Plant or buy a part of Deseret's Bonanza plant. The likelihood of this happening is uncertain but should be explored.

Outside the bubble, there are several possibilities. Two have been identified and are located adjacent to each other just north of Las Vegas, Nevada. They are the 530 MW Mirant CCCT and the 1060 MW Duke CCCT. The Mirant plant scheduled for commercial operation in April of this year, is mostly subscribed but the Duke facility may be available for part or full purchase. Construction on the Duke facility was halted a few months ago – it was originally scheduled for commercial operation at the same time as the Mirant plant. Currently the ability to move energy from either facility is limited to about 200 MW along our Red Butte transmission line.

Transmission upgrades for an additional 250 MW could be made at a cost of about $50 millior *(see the IRP for transmission upgrade discussions). Each of these facilities are designed fo* base-load operation and could only supply a limited amount of peaking capability.

New Plant Opportunities

For the past two months work has been underway to determine the best possible sites for new gas-fired generation facilities within the Utah bubble. This study will be finalized within the next few weeks as will the study to determine the best use of the Gadsby site. Investigations and discussions with third parties have also been ongoing to determine what opportunities are available for new projects within the bubble or adjacent to it. The results of this work are summarized by the following list of opportunities.

- Build additional gas-fired facilities at West Valley
- Repower the Gadsby site with 480 MW of CCCT
- Build new gas-fired facilities at the Oquirrh Substation on the West side of Salt Lake Valley
- Build new gas-fired facilities at the Terminal Substation in Salt Lake City
- Buy the Spring Canyon Energy, LLC position (owned by USA Power) and build new gas-fired facilities (240 MW of CCCT) at the Mona Substation 80 miles south of Salt Lake
- Buy the Toquop LLC position (owned by Vidler Water company) and build new gas-fired facilities (planned for 1000 MW of CCCT)10 miles northwest of Mesquite, Nevada
- Build Hunter 4

All of the above options with the exception of Hunter 4 would be gas-fired and could be either peaking or base-loaded facilities. Recent technology investigations and review indicate that the Company can meet the IRP heavy load hour peaking requirements by using CCCT facilities specifically designed to cycle day by day. Using this approach would eliminate the need for additional simple cycle peakers and would result in better heat rates and lower cost production.

Table 1 shows an economic comparison of combined-cycle plants built at the best of the above sites along with the expected economics of purchasing an existing Nevada facility. Also included are the comparative economics of Hunter 4. All production costs are shown in levelized values (as was done in the IRP). Spring Canyon is shown as both a dry cooled condenser version and a water-cooled condenser version (explained further in the recommendation section of this paper). Excluding Hunter 4, repowering Gadsby provides the best economics with Spring Canyon (water cooled) coming in a close second. Acquisition of a Nevada plant (a Mirant or Duke facility) is third if the plant could be purchased at a 50 % discount. Table 1 also differentiates between the base unit costs and those with duct firing. Duct firing has a higher heat rate but can be used for pure peaking capacity with a quick response time.

Table 1

Comparative Economics of East-Side Thermal Options

Levelized $/MWh

	Units	Spring Canyon Dry Cooled	Spring Canyon Water Cooled	Gadsby Repower	Toquop	Hunter 4	Nevada - Full Capital	Nevada - 50% Reduced Capital
Earliest Installed Date	Date	Dec-05	Dec-05	Jun-07	Apr-06	Jan-08	Jun-05	Jun-05
Listed Plant Output - Base	MW	210	210	420	440	575	460	460
Listed Plant Output - Duct Firing	MW	30	30	60	60		70	70
Base Unit Avg. Heat Rate	BTU/kWh	7615	7235	7235	7235	9483	7446	7446
Total Anticipated Capital Cost	$,1000's	$202,724	$ 213,364	$348,327	$357,017	$909,575	$366,632	$203,636
Base Unit Costs								
Total Variable Cost/MWh	$/MWh	$ 32.90	$ 30.03	$ 31.16	$ 39,02	$ 7.11	$ 40.04	$ 39.83
Total Emission Cost/MWh	$/MWh	$ 3.47	$ 3.23	$ 3.23	$ 3.36	$ 8.13	$ 3.46	$ 3.46
Total Capital & Other Costs/MWh	$/MWh	$ 14.22	$ 14.65	$ 11.99	$ 12.29	$ 20.41	$ 11.91	$ 7.04
Cost per MWh - Base Unit	$/MWh	$ 50.59	$ 47.91	$ 46.39	$ 54.67	$ 35.65	$ 55.41	$ 50.34
Cost per MWh - Base+Duct Firing	$/MWh	50.89	49.03	47.69	54.16	35.65	54.18	49.59

The only project that has any possibility of meeting heavy load hour peaking for a 2005 or even a 2006 commercial date is the Spring Canyon project. This project has just acquired its approval order from the state of Utah. The Toquop project would be possible a few months later because it is close to having all necessary permits. Hunter 4 cannot now meet a 2007 commercial date but the Gadsby repowering project could meet a 2007 date if given Company go ahead approval in the next two months.

RECOMMENDATIONS

Recognizing that MSP in not yet settled and that approving a full-blown project without it is not advisable, we recommend consideration of the following to keep the three best options viable and progressing until the Company is prepared to commit to large capital expenditures for new plants.

Spring Canyon Energy, LLC (240 MW 1x1 CCCT)

USA Power owns this project located adjacent to our Mona Substation. They have an approval order for the project from the State of Utah and also have options on water and land for the project. The project currently intends to use an air-cooled condenser. We believe there may be sufficient water available to use a more economic water-cooled condenser (see Table 1 above). We recommend buying the Spring Canyon Energy, LLC from USA Power and believe their position could be acquired for $5 million or less. We would propose a year long option agreement that would give USA Power an up front payment of no more than $500,000 with the remainder to be paid upon actual approval to proceed with the full project. We also recommend definitively determining the availability of buying sufficient water for a water-cooled condenser and proceeding with project engineering over the next several months at a cost about $500,000. The plant would be designed to cycle each day so as to be able to meet heavy load hour operation. At the end of the engineering period, a decision could then be made on proceeding further with the project. This would maintain the schedule and make possible a 2005 or 2006 commercial date.

Gadsby Repowering (480 MW CCCT)
We have now concluded that the best use for the Gadsby site is to build a 480 MW CCCT facility. Work is still being done to determine whether the plant should consist of two 1x1 240 MW units or one 2x1 480 MW unit. We recommend starting preliminary engineering after the Gadsby study is complete and preparing and submitting the NOI for this project. This effort will require from 9 to 12 months at an estimated cost of $400,000. This work would maintain a schedule that would bring the plant on line for the 2007 summer time frame.

Hunter 4 (575 MW)
The Hunter 4 NOI will be ready to submit the first week in February. Once a permit is secured, a process that will take from 9 to 12 months, we will have 18 months in which to start construction before the permit expires. We recommend submitting the permit consistent with the IRP requirement time frame. It should be noted that the NOI for IPP 3 was submitted last month and that the IPP 3 organization hopes to have an approval order by the summer of this year. We believe they will use the NOI to seek project financing – an effort that could take from 6 to 12 months or more. IPP 3 was designed based on Utah coal. It is doubtful that there is a sufficient coal supply in Utah for both an IPP 3 unit and for a Hunter 4 unit.

February 5, 2003

X	**For Approval**
	For Information
X	**For Discussion**

Performance CEC Meeting **February 5, 2003** **CEC020/03**

Title:	**Purchase of Project Positions at the Mona Substation Site**
Decision(s) Requested:	(1) Approval to immediately purchase the Panda Energy (Panda) project position adjacent to the Mona Substation site for $964,818.81 and approval to extend the two land option agreements at a cost of $42,168, (2) Approval to negotiate and purchase the USA Power site for up to $3,500,000, (3) Approval to spend up to $500,000 on preliminary engineering design, (4) Approval to issue an asset-based Request for Proposal (RFP) to meet the April 2005 IRP peaking need.
Executive Summary:	(1) Purchase of Panda's Mona position is cost effective as compared to self-developing viable build options (2) Purchasing the Panda and USA positions is strategic and critical in expanding opportunities to cost effectively meet the asset-based IRP requirements (3) Preliminary engineering is necessary to firmly establish a viable build alternative, and (4) In this instance, issuance of an RFP is required to appropriately compare buy versus build.
Key Issue(s) for Discussion:	Ability to cost effectively meet the IRP requirements for CY 2005, 2007, and 2008 and time is of the essence (as Panda desires to exit immediately before February 28, 2003 land option payment is due).
Sponsor:	Barry Cunningham, Senior Vice President Robert Klein, Senior Vice President
Author (if different):	Rand Thurgood, Managing Director Resource Development Mark Tallman, Director Origination

EXHIBIT 355
WIT. R Thurgood
DATE 9/28/06
CitiCourt, LLC

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EXECUTIVE SUMMARY

Generation and Commercial & Trading (C&T) seek approval to expend approximately $5,000,000 to acquire a strategic generation development site in Utah, associated meteorological data, and related land options. The purpose is to establish a viable generation build alternative to meet the 2005, 2007, and 2008 IRP target dates for a peaking asset plus two base-load assets. These resources are needed to supply PacifiCorp's eastern system. Generation and C&T are seeking approval to:

1. Authorize Generation to purchase the Panda position at Mona for $1,006,986.81 (consisting of $964,818.61 for site rights and $42,168 for related land options) and to extend these related land options.

2. Authorize Generation to negotiate and purchase USA Power's rights associated with their Mona site for a price not to exceed (without additional approval) $3,500,000.

3. Assuming the USA Power rights are acquired, authorize Generation to spend not more than $500,000 for preliminary engineering design during FY 2004, or assuming that only the Panda site is acquired, authorize Generation to spend not more than $500,000 for preliminary engineering design during FY 2004.

4. Authorize C&T to issue an asset-based RFP in March 2003 to meet the April 2005 IRP defined peaking need for the resource deficit of PacifiCorp's eastern system.

PacifiCorp published its Integrated Resource Plan (IRP) on January 24, 2003. The document shows an East system need for at least 200 MW of peaking resource by April 2005, a 570 MW base load resource by April 2007, and another 500 MW base load resource by April 2008. Resource Development has determined that only a limited number of viable sites exist along the Wasatch Front for resource development.

PacifiCorp has an immediate opportunity to purchase the rights to one of the most attractive of these sites (the Panda site located adjacent to the Company's Mona substation) for $964,818.81. This amount represents the direct cost incurred by Panda to develop the site. This purchase will provide PacifiCorp with both valuable meteorological data that must be collected for any site as well as the extension ability on two land purchase options by paying an additional $42,168 ($21,168 for 80 acres by February 28, 2003 and $21,000 for 160 acres in April 2003). Panda has agreed to an exclusivity agreement to sell this site for their cost. Panda desires to exit their position as soon as possible and prior to the date that the land option payment is due (February 28, 2003). The exclusivity agreement expires on February 12, 2003 to allow Panda to pursue a second alternative in the event PacifiCorp is not interested.

A second entity, USA Power, holds rights to another site adjacent to the Mona substation. Whereas the Panda site provides a viable alternative for a 2006 or for the 2007 and/or 2008 IRP target dates, the USA Power site additionally provides a viable alternative for the 2005 IRP target date. The USA Power site is further along in the permitting process. However, Panda holds valuable meteorological data that would be of value for the USA site since USA submitted their permits based upon inferred data rather than actual data. Absent the purchase of the Panda site by PacifiCorp, USA power is the next most likely suitor for the Panda site. We believe the USA site to be the only viable project site that is capable of meeting a 2005 online date for a peaking unit with an efficient combined cycle design (versus a simple cycle design). This means that the data from the Panda site could prove to be key if the permitting process associated with the USA site is questioned for data quality reasons.

We are recommending that both sites be acquired. USA Power has indicated a willingness to negotiate but they are not willing to sell for cost. Generation believes the cost of the Panda rights to be reasonable and appropriate when compared against the cost of acquiring such data.

It is critical for the Company to hold these rights to improve PacifiCorp's bargaining position. The existence of viable alternatives is the most important factor when attempting to negotiate cost effective purchases. This will continue to be the case as the Company endeavors to cost effectively meet the asset-based IRP requirements. . The roughly $5,000,000 expense on the part of the Company will provide many times that amount in negotiating value for customers as build versus buy comparisons are made. For comparison purposes, the expected cost of 200 MW in third party transmission from the Northern Nevada market for a 2-year period would exceed $7.9 MM. Likewise, the expected cost of fees to exit the California ISO at Mona would exceed $17 MM for a 200 MW peaking resource that dispatches 50% of the hours in a year.

Acquisition of the sites from Panda and USA will provide the Company, in conjunction with the Gadsby re-powering opportunity and the planned permitting of Hunter 4, sufficient viable options to fulfill a large portion of the asset-based IRP need in the event the market fails to provide more cost effective asset-based solutions.

STRATEGIC IMPLICATIONS OF THE PURCHASES

PacifiCorp published its IRP on January 24, 2003. The document shows an East system need for 200 MW of peaking resource by April 2005, a 570 MW base load resource by April 2007, and another 500 MW of based load resource by April 2008.

To better evaluate the overall asset-based market, the PacifiCorp commissioned CH_2Mhill to conduct a siting study for gas-fired generation along the Wasatch Front. This study is now nearing completion and it strongly indicates that the Mona area is one of the best areas (if not the best area) for the development of gas-fired generation to meet peaking and/or base load generation needs. The Mona area is attractive because of its strategic location near the Utah market, major electrical transmission lines and two major gas transportation lines. In addition, we have determined (through bi-lateral discussions with developers) that only a limited number of options are available to meet either the peaking resource requirement date of April 2005 or the base-load resource date of April 2007.

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The options for addressing the 2005 date are as follows:

- **Wheel In** - Procure (purchase, build or buy) the required 200 MW of asset-based peaking resources in another control area(s) and secure firm transmission rights to wheel the power to the resource deficit portion of PacifiCorp's East system (the Utah Bubble). For comparison purposes of the expense being proposed herein, the expected cost of 200 MW in third party transmission from the Northern Nevada market for a 2-year period would exceed $7.9 MM. Likewise, the expected cost of fees to exit the California ISO at Mona would exceed $17 MM for a 200 MW peaking resource that dispatches 50% of the hours in a year.

- **Purchase Within** - Purchase the required 200 MW of asset-based peaking resources from points inside the Utah Bubble. Absent the USA Power site, Generation and C&T are unaware of other entities capable of meeting an April 2005 date with a combined cycle machine,

- **Build Within** - Build PacifiCorp's own resources within the Utah Bubble.

PacifiCorp's build options for meeting the 2005, 2007, and 2008 IRP requirements are as follows:

Build Options to Meet IRP Target Dates

Option	April 2005 Target Date (peaker)	April 2007 Target Date (base-load)	April 2008 Target Date (base-load)
Re-power Gadsby		YES	YES
Hunter 4			YES
Panda site	YES*	YES	YES
USA Power Site	YES**	YES	YES

* - Using simple cycle technology only.
** - Using combined cycle technology.

Repower Gadsby
Gadsby Units 1,2 and 3 can be repowered at a capacity of 550 MW (490 MW of base capacity and 60 MW of duct firing peaking capacity). If started in February 2003, this project could be brought on line in March of 2007 and be available to meet the first base-load target date of April 2007.

Hunter 4
This 575 MW coal-fired project can meet the second base-load target date of April 2008 (online February 2008) if started in February 2003.

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Panda Mona Project
The Panda site adjacent to Mona can accommodate up to 1,000 MW of peaking and/or base-load resource. An online date of April 2005 can be achieved at the Panda site using simple cycle technology and an online date of March 2006 can be achieved using combined cycle technology. More importantly, as described below, control of the Panda site is expected to be instrumental in negotiations with respect to the only known site that can accommodate combined cycle construction to meet the April 2005 timeline.

USA Power Spring Canyon Project
The USA Power site is also adjacent to Mona. Indications are that USA Power has traveled far enough through the permitting process to support an online date of April 2005 using combined cycle technology (250 MW 1X1 CCCT). While this online date is assertive, it is achievable through close management, the immediate start of engineering design work, and the reservation/ordering of equipment by no later than the end of March 2003.

The most cost effective resource design for meeting the 2005 peaking need is a combined cycle design (as compared to a simple cycle design). The recommendation is that PacifiCorp meet the April 2005 peaking resource need with a combined cycle design that is capable of being operated in a peaking mode.

Informal discussions have begun with USA Power with respect to purchasing their site. To date, USA Power has indicated an interest in selling their project position. Owning the Panda position is critical to defining the limits of further negotiations with USA Power because it provides PacifiCorp with a viable build option to meet the April 2005 peaking date (albeit with a simple cycle design). Further, the Panda meteorological data has been of significant interest to USA Power (USA's application relies on inferred data versus actual data). Owning the Panda site, and associated meteorological data, validates USA's air permit application and enables either of the sites to be expanded up to 1,000 MW. If PacifiCorp does not acquire the Panda site, we believe USA Power will try to acquire the site for (at minimum) the associated valuable meteorological data.

The optimal outcome would be to acquire both the Panda and USA Power sites. This would provide the Company with the most flexible and cost effective build alternative for all three of the IRP target dates. If PacifiCorp owned both the USA Power and Panda positions, we would combine the projects and immediately begin engineering to secure a viable combined cycle build option for meeting the April 2005 target date for a peaking resource.

Concurrent with this action, we are preparing to issue an RFP for asset-based purchases. Results from the RFP would be used to determine the most economical alternative in meeting the April 2005 peaking need. In the event we are able to negotiate a purchase option more economical than building, the site rights would be held and utilized to assure that a viable build option exists for meeting the 2007 and/or 2008 target dates.

As the IRP action plan indicates, a variety of resource alternatives will be required to meet the IRP requirements over the next 10 years. Having viable build options available for our customers is critical to assure reliability and to assure that the Company is able to receive the most economical asset-based offers from the market place as we assess build versus buy options. The Panda and USA sites discussed herein will provide just such an option. These sites are adjacent to Mona and provide the potential to build up to 1,000 MW of gas-fired generation. Additionally, these sites hold additional strategic value since Hunter 4 and Gadsby re-power are subject to permitting risk.

Finally, we believe the Panda and USA Power assets have market value and could be re-sold at a later date if PacifiCorp does not develop a Mona area project.

THE PANDA MONA POWER PROJECT

During the high market period of 2000, Panda initiated a project adjacent to our Mona Substation with the intent of constructing up to 1,000 MW of gas-fired generation. Panda purchased options on 240 acres of land and began discussions for the purchase of water. Most importantly, they also erected a tower to collect meteorological data necessary for obtaining the required Prevention of Significant Deterioration (PSD) air permit. A data collection protocol was prepared and accepted by the State of Utah. This ensured that any data collected over the 14-month period would be PSD qualified. In addition to this work, Panda also conducted transmission and market studies and prepared an air modeling protocol that was also accepted by the State.

Since the market decline, Panda has been holding its information and position on their project at Mona. They now believe that it will be at least four to five years before a true merchant position will be available to them at their site. They are now willing to sell for cost their information and attendant assets as follows:

Panda Plant Site Property:
Two land purchase option agreements:

- Tract A:
  - 80-acre tract located adjacent to the Mona Substation
  - Property option up for renewal on 2-28-03
  - Renewal cost will be $21,168. **Property option must be exercised 2-28-04.**
  - Exercise price is $211,680.
- Tract B:
  - 160-acre tract located adjacent to Tract A
  - Property option up for renewal 4-16-03
  - Renewal cost will be $21,000. **Property option must be exercised 4-16-04.**
  - Exercise price is $110,400.

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Panda Environmental Permitting:

- Environmental Site Evaluation and Planning Report
- Ground Water Study Feasibility Screening Study Report
- Meteorological and Air Quality Monitoring Quality Assurance Plan –approved by Utah Department of Air Quality (UDAQ)
- Dispersion Modeling Protocol approved by UDAQ
- Air Quality PSD Monitoring Protocol
- 1-year Audited Meteorological data from the plant site property
- Meteorological Tower and associated equipment

Panda Electrical Transmission and Marketing Reports:

- Market Study from R.W. Beck
- Transmission Study from R.W. Beck
- PacifiCorp Interconnect Study Report

Panda has agreed to sell the above for their expended cost to date - $964,818.81. Addition of the land option expenses would bring PacifiCorp's total expense to $985,986.81 in the current fiscal year and $21,000 in the following fiscal year.

We have reviewed the purchase price of $964,818.61 and believe it to be a cost-effective alternative to acquiring necessary meteorological data and land options on our own. Data collection must be performed by every site (for permitting reasons) and must be acquired for a year or more.

THE USA POWER MONA POWER PROJECT

Similar to Panda, USA Power initiated a project adjacent to our Mona Substation during the high market period of 2000. Initial discussions with USA Power indicate that USA Power is willing to entertain an offer to purchase:

- Spring Canyon, LLC. (legal owner of USA Power's project position at their Mona site)
- Approval Order (air permit) from UDAQ to proceed with 250 MW project
- Options on water sufficient to operate the project
- Option on land for the project

TIME REQUIREMENTS OF THE PANDA PURCHASE

Panda has agreed to an exclusivity agreement to sell the site to PacifiCorp at their cost. Panda desires to exit their position as soon as possible and prior to the date that a land option payment is due (February 28, 2003). The exclusivity agreement expires on February 12, 2003, to allow Panda to purse a second alternative in the event PacifiCorp is not interested.

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RECOMMENDATION

We recommend and request the following:

1. *The authority to purchase the Panda position at Mona for $1,006,986.81 and extend the associated land options*. This opportunity represents the best and most cost effective alternative available to secure viable build options. We have contacted every known developer who holds rights to viable sites such as this and Panda is the only entity who has expressed a sincere interest to sell their rights at cost. Failure to secure the Panda site will materially reduce PacifiCorp's negotiating ability in comparing build versus buy alternatives for meeting the 2007 and 2008 IRP target dates for assets in the Utah Bubble.

2. *We request authority to negotiate and purchase USA Power's rights associated with their Mona site.* We will not spend more than $3,500,000 for these rights without additional approvals.

3. *If we acquire the USA Power site, we request the authority to spend up to $500,000 (during FY 2004) for engineering design*. This design work will be applicable and necessary to firmly establish a viable build alternative for the 2005, 2007, and 2008 IRP target dates. In the event Generation is not able to acquire the USA Power site, but approval is granted to acquire the Panda site, Generation is seeking authority to spend up to $500,000 during FY 2004 for preliminary engineering design for the Panda site.

4. We request the authority to issue an asset-based RFP in March or April 2003 to meet the April 2005 IRP peaking need for the Utah Bubble.

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