Tribal Renewable Energy – Final Technical Report

Project Title: Hualapai Tribal Utility Development Project

Date of Report: May 25, 2008

Recipient Organization: Hualapai Tribal Nation

Award Number: DE-FG36-05GO15169

Partners: Hualapai Tribal Nation

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Hualapai Tribal Utility Development Project
Executive Summary

Background:
The Hualapai Tribe has been experiencing an energy crisis of sorts for many years. As is typical for rural tribes, their location on the end of their existing utility's grid has subjected them to high costs and poor reliability of electric service. The Tribe's economic development enterprise on the Grand Canyon, Grand Canyon West (GCW), has been operating without grid power for the past seven years. This situation has motivated the tribe to examine the use of renewable energy to meet its power needs in remote areas. The Tribe currently operates the longest solar powered water pipeline in North America to pump water to Grand Canyon West. The USDA Rural Utilities Service has funded the construction of a large hybrid solar power system and utility distribution mini-grid at Grand Canyon West. The Tribe is currently monitoring their wind resources with the assistance of NREL and the BIA with a look toward development of both local community wind power projects and a utility scale wind farm.

The first phase of the Hualapai Tribal Utility Development Project (Project) studied the feasibility of establishing a tribally operated utility to provide electric service to tribal customers at Grand Canyon West.

The project was successful in completing the analysis of the energy production from the solar power systems at Grand Canyon West and developing a financial model, based on rates to be charged to Grand Canyon West customers connected to the solar systems, that would provide sufficient revenue for a Tribal Utility Authority to operate and maintain those systems. The objective to establish a central power grid over which the TUA would have authority and responsibility had to be modified because the construction schedule of GCW facilities, specifically the new air terminal, did not match up with the construction schedule for the solar power system. Therefore, two distributed systems were constructed instead of one central system with a high voltage distribution network.

The solar power systems at GCW are being maintained by GCW Maintenance Department staff and a qualified solar power system contractor, currently under contract to the solar system builder, APS Energy Services (APSES). At the end to the contract term with APSES responsibility for maintenance and operations of the solar power systems will revert to the Hualapai Tribe. It is anticipated that GCW maintenance personnel will continue to perform daily system checks and that the solar system contractor will be retained by GCW to keep the system operational and meet the manufacturer's warranty requirements.

The Hualapai Tribal Council has not taken the action necessary to establish the Tribal Utility Authority that could be responsible for the electric service at GCW. The creation of a Tribal Utility Authority (TUA) was the subject of the second objective of the project.

The second phase of the project examined the feasibility and strategy for establishing a tribal utility to serve the remainder of the Hualapai Reservation and the feasibility of including wind energy from a tribal wind generator in the energy resource portfolio of the tribal utility .

The Project was successful in conducting the analyses necessary to choose among options for the structure of a tribally controlled utility, to develop a pro forma financial projection of the costs and revenues necessary to sustain it, and to develop all of the organizational documents necessary to form a legal entity for the purpose of providing utility service on the Hualapai Reservation.

Project consultants presented options and legal considerations of a variety of possible utility structures based on examination of the structure of existing tribally controlled utilities. The Tribal Utility Authority model was selected as the preferred structure due to its stability as an entity apart from other tribal government functions.

Project consultants gathered data on reservation electric loads and rates charged by the local electric coop as well as information on the tribe's federal hydropower allocation, the cost of power purchased on the open market, and the use of wind energy from a hypothetical wind generator located on the Hualapai Reservation. The result was that power could be provided by a TUA at prices that were competitive with the local coop. The benefit would be in tribal control of reservation electric infrastructure, an improved quality of maintenance activities on the local power distribution system , and improved customer relations based on a local utility office with intimate knowledge of the needs of tribal customers. Under the conditions of the study, the use of wind energy from a single wind turbine proved not to be economical and would in fact require an increase in energy prices to Hualapai customers.

The project team developed a draft ordinance that would establish the TUA under tribal law and establish the structure and authority of the TUA. The project team also developed a Utility Plan of Operation, in effect a set of by-laws for the TUA, that defines many of the TUA's operational and administrative policies and procedures. These documents along with the Pro Forma Financial Analysis were presented to the Hualapai Tribal Environmental Review Commission for review and have not yet been presented to the Tribal Council for consideration.

The short-term implementation of the TUA could establish the TUA and instruct it to begin providing service at Grand Canyon West because the tribe owns all of the facilities there and there are no legal obstacles. On the other hand, establishment of the TUA would be the first step taken by the Tribe toward negotiations with Mohave Electric to establish the terms and conditions under which ownership of the Reservation power system would be transferred to the tribe. There are numerous financial considerations and legal obstacles to the transfer of ownership that will require complex negotiations. In the short term, the Tribal Council could authorize the TUA to undertake those negotiations in an effort to put real numbers into places in the pro forma financials where estimates have been used such as the value that Mohave Electric would place on the Hualapai power system and the cost to Mohave to provide service to non-tribal customers that currently are on the same power lines that serve the Reservation.

It is currently unknown when the Tribal Council will consider the implementation of the results of the study.

Project Objectives:

Objective 1:

Develop the organizational structure and operational strategy for a tribally controlled utility to operate at the tribe's tourism enterprise district, Grand Canyon West.

The project coordinated the development of a tribal utility structure with the development of the GCW Power Project construction of the power infrastructure at GCW, developed the maintenance and operations capacity necessary to support utility operations, developed rates for customers on the GCW "mini-grid" sufficient for the tribal utility to be self-sustaining, and established an implementation strategy for tribal utility service at GCW.

Objective 1.1 Project Team Development –
The Project was successful in all regards concerning the assembly of a highly qualified project team for the development of a tribally controlled utility to operate the solar power systems at Grand Canyon West.

The work of the Tribe's solar power system contracto, APS Energy Services, was coordinated by Mark Randall of Daystar Consulting, LLC in his role as Project Manager for the RUS funded Grand Canyon West Solar Power System Construction Project. Mr. Randall worked with the contractor to gather the necessary solar system load and performance data that was needed for the economic and maintenance and operations analyses.

Mr. Leonard Gold, of Utility Strategies Consulting Group, successfully performed the power production cost economic analysis and a pro-forma projection of operational costs and rates for customers connected to the solar power systems.

Mr. Dean Suagee, of Hobbs, Straus, Dean & Walker, LLP, worked through a variety of options for organization of a tribally controlled utility and produced an ordinance authorizing the Tribal Utility and contributed to the Tribal Utility Plan of Operations.

Mr. Jack Ehrhardt, Director of the Hualapai Department of Planning and Economic Development, served as liaison to tribal managers at Grand Canyon West and the Tribal Environmental Review Commission which served as the Project Oversight Committee.

Objective 1.2 Coordinate Utility Development at Grand Canyon West
The project was successful with regard to this objective in that all of the necessary elements of an assessment of the feasibility and a plan for a tribally controlled utility to provide electric service at Grand Canyon West were successfully identified and established in the completed Plan of Operations and Tribal Utility Ordinance.

However, the scope of the original project, which was to establish a central utility infrastructure based on the RUS funded Solar Power project, had to be altered because the construction of new facilities at Grand Canyon West could not be coordinated with the Solar Power System construction schedule. Therefore, the construction of the first segment of a central electric utility grid did not happen as planned. Rather than a centralized solar power system and high voltage distribution grid, two distributed solar power systems were constructed and not connected together. Additionally, the authority to include non-solar loads in the Project was restricted by the Grand Canyon West staff and those loads were not included in the energy analysis or the pro-forma projections for rates to be charged to customers. The analysis and pro forma was limited to the loads connected to the two solar power systems, one of which powers the loads at the residential and maintenance shop area, and the other provides power to the air terminal facility.

Objective 1.3 Tribal Utility Structure Options

This objective was successfully completed as the Project team examined a variety of organizational structures that have been established by other tribes that have formed tribally controlled utilities. The model of a Tribal Utility Authority emerged as the preferred choice because its independence from political shifts in the tribal government would be established by a tribal ordinance. It is possible that the operation of the TUA could be established as a function of tribal department prior to the establishment of the TUA by Ordinance.

Objective 1.4 Develop Rates for Customers at Grand Canyon West

The Project successfully analyzed the cost of producing power from the two distributed solar power systems at the Air Terminal and Residential Area. Using data collected from the solar systems, records of service costs for the diesel generators, and projections of diesel fuel costs, a financial pro forma projection of cost per kilowatt hour of energy delivered to Grand Canyon West customers was established. The administration costs for a tribal utility necessary to provide that level of service was designed based on the use of existing Grand Canyon West personnel to do the daily maintenance checks and specialty contractors to perform routine service and repair functions. The calculated rates to support the tribal Utility operation of the solar power systems at Grand canyon West were significantly lower per kilowatt hour that the cost to GCW for their existing non-solar diesel power systems.

Objective 1.5 Develop Maintenance and Operations Capacity at Grand Canyon West

The Project successfully established the capacity to operate and maintain the solar power systems at Grand Canyon West. Existing GCW Maintenance Department staff were trained to perform daily system performance checks and to clear minor fault conditions as they appear. For the six-month period from December 2007 through May 2008, APS Energy Services will pay the cost of maintaining the system by hiring a qualified solar power system contractor to perform the periodic maintenance requirements such as battery watering, PV module cleaning, and a list of other maintenance functions and checks required by the equipment manufacturers. At the expiration of the APSES maintenance period, the responsibility for maintaining the systems will shift to the Hualapai Tribe. It is expected that Grand Canyon West, will assume responsibility for the cost of the solar power system contractor because it is in GCRC's interest to maintain a power system that provides power at half the cost of the non-solar alternative.

Objective 1.6 Implement Tribal Utility Service at Grand Canyon West

At this time, this objective has not been completed. All of the necessary elements for implementation, the Tribal Ordinance to establish a Tribal Utility Authority, the Plan of Operations for the TUA, and the Pro Forma Financial Projections and rates, are all completed. However, the Hualapai Tribal Council has not taken action on this issue. Tribal

Council Action would establish the TUA by Ordinance and establish the TUA's budget and authority to charge rates for delivered electricity to customers at Grand Canyon West. It is currently unknown when the Hualapai Tribal Council will consider this issue.

Objective 2 –
Develop a strategy for tribal utility takeover of electric service on the Reservation.

The Project performed a cost analysis of reservation electrical service, and developed an implementation strategy for tribal takeover of reservation electrical service. The analysis included the examination of options and costs associated with integration of the tribe's hydro power allocation and wind resources.

Objective 2.1 Tribal Utility Options and Structure

This objective was successfully completed. Utility Strategies Consulting group submitted copies of the operating rules for a few existing tribal utilities for review and consideration as a model for the Hualapai Tribal Utility. Dean Suagee completed a draft white paper outlining possible options and legal considerations for the Project Team and Project Monitoring Committee to consider prior to development of a selected alternative.

Project consultants completed a draft Tribal Utility Ordinance (Ordinance) and Plan of Operations. The Ordinance is a document adopted by resolution of the Tribal Council authorizing the formation of the Tribal Utility and describing the utility's authority and structure. The Plan of Operation describes the internal policies that govern utility, in effect, the bylaws. The draft was circulated among project team members and Hualapai staff for comments. A draft was reviewed by the Project Oversight Committee and comment received. The final draft has been prepared for presentation to the Hualapai Tribal Council.

Objective 2.2 Cost Analysis of Reservation Electrical Service

This Objective was successfully completed. Tribal representatives met with Mohave Electric Cooperative (MEC) representatives to explain the Hualapai Tribal Utility Project and request tribal load data, system maintenance records, and system maps.

Utility Strategies Consulting Group (USCG) completed a first draft of a tribal electrical load projection using older data from the Tribe's applications for a federal hydropower allocation. MEC provided the two most recent years of customer data and USCG updated the load projections and pro-forma economics. Consultant Glenn Reddick completed an inventory of reservation electrical utility infrastructure, a system valuation study, and condition report. MEC provided Maps of the Reservation electrical distribution system.

Project consultants developed a load and rate pro forma projection based on the load data provided by MEC. The rate projections were reviewed by the project team. The pro forma includes data from projections of operations and maintenance costs determined through the system valuation study. Final costs for debt service and O&M are subject to negotiations with MEC concerning tribal acquisition of the system that are not within the scope of this study.

Projections of the output and estimates of the revenue from sale of electricity from a 1.5 Megawatt wind turbine in Peach Springs were provided from the Hualapai BIA-Energy and Mineral Development Program Wind Energy Assessment Project. The estimate was prepared by an experienced wind energy analyst based on wind data recorded at two sites near Peach Springs. The value of the potential revenue from sale of Hualapai wind power was included in the financial pro-forma as a sensitivity to the base case revenue analysis.

Based on assumptions of conventional financing without any subsidies, the inclusion of the output from a 1.5MW wind turbine in the mix of energy sources required to meet the load demands of Hualapai Reservation customers which includes the Tribe’s allocation of federal hydropower and purchases of energy on the open market, would have caused the necessity of raising rates to Hualapai customers. Therefore, the pro forma financial analysis and report did not recommend the inclusion of Hualapai wind energy resources under those conditions.

FEASIBILITY REPORT

ESTABLISHING A

HUALAPAI TRIBAL UTILITY AUTHORITY

PREPARED
FOR THE

HUALAPAI TRIBAL NATION

FINAL DRAFT

SEPTEMBER 26, 2007

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Establishing A

Hualapai Tribal Electric Utility Authority

Executive Summary

The Hualapai Tribal Nation (Hualapai or Tribe) is investigating the opportunity to form a Tribal Utility Authority (TUA) to provide retail electric service to customers on the Hualapai Reservation (Reservation). A grant from the US Department of Energy funded this study of the Reservation electric utility infrastructure and options for establishing a Tribally controlled electric utility. This report examines the feasibility and costs of two scenarios. The first is to form a TUA to provide electric service to just the Grand Canyon West (GCW) area. The second is to provide electric service to both the GCW area and the remainder of the Reservation, principally, the Peach Springs area where the vast majority of tribal members and Reservation electrical loads are located.

Currently the Tribe has a grant-funded project underway at GCW to upgrade the distribution system and to build a solar-diesel hybrid power system to meet loads at the air terminal facility and the residential area. The remainder of the Reservation, including the Peach Springs area is currently served by Mohave Electric Cooperative (MEC). Peach Springs and GCW are not electrically interconnected, but both areas are within the Reservation's boundaries and could be operated either separately or as one entity with a common management structure.

This report provides the Hualapai Tribal Council (Council) with the information needed to make a decision regarding the formation of a TUA to oversee providing electric service to GCW alone or GCW and Peach Springs together. The report examines the organizational issues related to forming a TUA; the costs associated with acquiring the on-Reservation MEC distribution system for providing service to the Peach Springs area; the condition of the MEC facilities on the Reservation; and the costs associated with the different scenarios. The actual implementation of providing electrical service to either GCW alone or combined with the Peach Springs area is beyond the scope of this study.

The instrument for implementing the formation of a TUA is an Ordinance, (Appendix B) which would establish, in Hualapai tribal law, the legal entity of the Hualapai Tribal Utility Authority and establish its legal responsibilities and authority. Actually providing electrical service to Hualapai customers would require detailed planning by the TUA, once established, and detailed negotiations with third party providers of services as required to establish actual costs. The transition to TUA provision of electric services on the Reservation would be subject to approval by the Council prior to implementation.

A System Valuation Assessment was conducted to establish the current value and condition of the electrical infrastructure (poles, wires, transformers, and other equipment). The results of the System Valuation Assessment were used to establish estimates, based on standard utility pricing practices, for the amount of money that MEC might expect to be paid for those facilities and what the expected maintenance and replacement cost might be over the next 5 years. It is impossible get an exact cost of purchasing the facilities without entering into direct negotiations with MEC. The adoption of the Ordinance forming the TUA structure would be a signal to MEC that the Tribe is serious about acquisition of the Reservation facilities and the first step toward initiating negotiations.

The results of the economic analysis indicate that GCW alone would provide sufficient revenues to recover the cost of operating the solar/diesel electric generating system. However, the cost/benefit analysis of the Peach Springs area indicates that there would need to be some increased revenues, either through adjustments to rates or through some type if subsidy by the Tribe, in order to recover the cost of operating the system. The Base Case indicates that revenues would need to increase to recover costs by $47,408 or 5.47% in the first year with additional increases in revenues as shown in Table 3 below. Case A, which includes the installation of a wind turbine in the Peach Springs area, indicates revenues would need to increase to recover costs by $241,415 or 27.87% in the first year with additional increases in revenues as shown in Table 5 below. Specific revenue increases would depend on the actual costs associated with each case, such as the cost to purchase the MEC system and the cost of an operating, maintenance and construction contractor.

	A	B	C	D	E	F
109	**Table 3 - PS & GCW Base Case Proforma Summary**					
110		**Annual Summary**				
111		**2007**	**2008**	**2009**	**2010**	**2011**
112	Total Revenue - $	$ 866,071	$ 901,676	$ 923,790	$ 946,485	$ 970,454
113	Plus Revenue Adjustment From Prior Year- $	$ -	$ 47,408	$ 79,434	$ 104,092	$ 129,319
114	Net Projected Revenue - $	$ 866,071	$ 949,084	$ 1,003,224	$ 1,050,577	$ 1,099,773
115	Needed Revenue - $	$ 913,479	$ 981,110	$ 1,027,882	$ 1,075,804	$ 1,125,037
116	Plus Current Year Adjustment - $	$ 47,408	$ 32,026	$ 24,658	$ 25,227	$ 25,264
117	Adjusted Revenue - $	$ 913,479	$ 981,110	$ 1,027,882	$ 1,075,804	$ 1,125,037
118	% Yearly Increase	5.47%	3.37%	2.46%	2.40%	2.30%

	A	B	C	D	E	F
109	**Table 5 - PS & GCW Case A Proforma Summary**					
110		**Annual Summary**				
111		**2007**	**2008**	**2009**	**2010**	**2011**
112	Total PS Purchase Power Costs	$ 866,071	$ 901,676	$ 923,790	$ 946,485	$ 970,454
113	Plus Revenue Adjustment From Prior Year- $	$ -	$ 241,415	$ 263,634	$ 287,736	$ 312,288
114	Net Projected Revenue - $	$ 866,071	$ 1,143,091	$ 1,187,424	$ 1,234,221	$ 1,282,742
115	Needed Revenue - $	$ 1,107,486	$ 1,165,310	$ 1,211,526	$ 1,258,773	$ 1,307,188
116	Plus Current Year Adjustment - $	$ 241,415	$ 22,219	$ 24,102	$ 24,552	$ 24,446
117	Adjusted Revenue - $	$ 1,107,486	$ 1,165,310	$ 1,211,526	$ 1,258,773	$ 1,307,188
118	% Yearly Increase	27.87%	1.94%	2.03%	1.99%	1.91%

By forming a TUA the Tribe would benefit by having a legal entity with responsibility for oversight and management of Reservation electric related issues. While the implementation of the TUA would not have an immediate impact on the chief complaint among Hualapai Tribal members, concerning large numbers and long duration of power outages, it would establish the ability for the TUA to plan and implement programs and projects that could improve system reliability over time. The primary difference would be tribal versus non-tribal control.

Establishing a TUA could result in the following benefits:

1. Improved response over time to local (on Reservation caused) outages.
2. Ability to plan and implement improvements to on-Reservation facilities and off-Reservation relationships that can improve system reliability.
3. Implement distributed generators at critical facilities for back-up power during outages.
4. Control of planning process for new facilities and establishing service in new areas of the Reservation.
5. The TUA can be a focal point for Tribal interaction with state and federal entities to address Reservation energy issues.
6. Tribally focused customer service that addresses the specific needs of Hualapai customers on the Reservation such as payment programs and personal contact with TUA customer service representatives.
7. Efficient investment in maintenance of Reservation electric facilities.

This report recommends that the Council adopt the Ordinance establishing the Hualapai Tribal Utility Authority and give the TUA, once established, the responsibility of establishing programs and implementing programs to increase and improve Tribal control of Reservation electric power. Based upon the analysis, the report also recommends that the first area that the TUA should provide electric service to would be the GCW area. After this is established, the TUA could then begin negotiations with MEC for the acquisition of the Peach Springs area electric facilities.

1. Introduction

The Hualapai Reservation (Reservation) encompasses a million acres along 108 miles of the Colorado River and the Grand Canyon. An Executive Order created the Reservation in 1883. Peach Springs, the tribal capital, is 50 miles east of Kingman on Historic Route 66 and owes its name to peach trees growing at springs nearby. The Reservation occupies part of three northern Arizona counties, Coconino, Yavapai and Mohave. The Reservation's topography varies from rolling grassland to forest and the rugged canyons of the Colorado River. Elevations range from 1,500 feet at the Colorado River to over 7,300 feet at the highest point of the Aubrey Cliffs, which are located on the eastern portion of the Reservation.

The total population of the Hualapai Reservation is approximately 1,621 of whom 1,353 are tribal members (2000 U.S. Census). Total tribal membership, including members not residing on the Reservation, is approximately 2,000. Tribal, public school, state and federal governmental services provide the bulk of current full-time employment. A nine-member council governs the Hualapai Tribal Nation.

The principal economic activities are tourism based enterprises, cattle ranching, and arts and crafts. The Reservation area offers hunting and fishing. An outdoorsman's paradise, the Tribe sells big-game hunting permits for desert bighorn sheep, trophy elk, antelope and mountain lion. The Colorado River bounds the northern edge of the Reservation. Hualapai River Runners (the only Indian-owned and operated river rafting company on the Colorado River) offers one and two-day trips in the Grand Canyon.

Offering an alternative to the congested National Park, Grand Canyon West attracts more than 8,000 [Jack – Do you have a better figure?]guests each month. Lake Mead National Recreation Area lies to the west of the Reservation.

The Tribe is investigating the opportunity to provide retail electric service to the customers in the Peach Springs area. In addition, the Tribe is in the process of upgrading the electrical distribution system that serves the Grand Canyon West

(GCW) area. While these areas are not electrically interconnected, both areas are within the Reservation and could be operated either separately or as one entity with a common management structure.

This report provides the Council with the information needed to make a decision regarding the adoption of the Ordinance forming a TUA that would oversee the provision of electric service to GCW alone or GCW and the Peach Springs area together. It examines the organizational issues related to forming a TUA; the costs associated with acquiring the MEC distribution system for providing service in Peach Springs; the condition of the MEC facilities on the Reservation; and the costs associated with the different scenarios.

Part of the evaluation focuses on the acquisition of the MEC facilities on the Reservation that serve the Peach Springs area. At this point, no discussions have been held with MEC regarding the transference of the electric facilities on the Reservation to the Tribe. If and when the Council decides to form a TUA, discussion and negotiations with MEC would need to be conducted. This report includes an estimated value of $210,000 that the Tribe might pay MEC for its electric facilities that serve the Peach Springs area. However, MEC's valuation of the on-Reservation electric facilities may differ. Only upon negotiations with MEC would the actual costs for acquiring the facilities be determined.

In addition, this report includes an assessment of the existing condition of the MEC facilities on the Reservation. This information is useful in determining the ongoing operation and maintenance costs of the MEC system.

The Tribe currently provides power to the GCW area. With a grant from the U.S. Dept. of Agriculture, the Tribe is working to install a new distribution system and approximately 32 kW of solar power. Regardless of the outcome of the Peach Springs area issues, the TUA could be responsible for operating and maintaining the GCW system. The question to be considered is whether to form a TUA to serve just the GCW area or to serve both the GCW and Peach Springs areas.

2. The Hualapai Tribe Governmental Structure

The Hualapai Tribal Nation (Hualapai or Tribe) is a federally recognized Indian tribe which exercises self-government pursuant to the Hualapai Constitution, adopted in 1991 and approved by the Secretary of the Interior pursuant to the Indian Reorganization Act of 1934. Article III of the Constitution provides for two separate and independent branches of government: a legislative branch and a judicial branch.

The legislative branch is comprised of the Tribal Council and the Tribal Administration. The Tribal Council consists of nine members, each of whom is elected for a term of four years. Elections for the Tribal Council are held every two years. The Tribal Council includes a Chairperson and a Vice Chairperson. These two officers are elected as such by the tribal membership, and they generally have the right to vote in Council meetings. The Constitution also provides that there shall be a Secretary and a Treasurer of the Council, who are to be chosen by the Council either “from within or without the Tribal Council membership.” If such officers are appointed from outside the Council membership, they do not have the right to vote in Council meetings. Regular Council meetings are held monthly, and special meetings may also be held. The powers of the Tribal Council are set out in Article V of the Constitution.

As provided in Article VII, the Tribal Administration consists of the Chairperson, Vice Chairperson, Secretary, and Treasurer of the Tribal Council, plus such other persons as may be designated by the Council. The Chairperson is in charge of the Tribal Administration and is responsible for overseeing the administration of tribal business and exercising powers delegated by the Tribal Council. As such, Tribal Administration is in many practical ways like an executive branch of tribal government. Article III expressly states, however, that the “Tribal Administration shall be subordinate to the Tribal Council.”

The Judicial branch of government, as provided in Article VI, consists of a Tribal Court and a Court of Appeals. Judges are appointed by the Council for two-year terms, and may be removed for reasons set out in Article VI, Section 7. The tribal courts have jurisdiction over all cases and controversies within the jurisdiction of the Tribe by virtue of the Tribe's inherent sovereignty or which may be vested in tribal courts by federal law.

3. Background of MEC Relationship

Currently, MEC provides electrical service to each house or commercial building in the Peach Springs area based on individual contracts. Existing contractual issues that impact the Tribe as a whole relate to easements provided to MEC and related tax, easement, and usage fees. There may be other historical agreements between MEC and the Tribe that relate to MEC's use of tribal lands or facilities.

MEC filed its Articles of Incorporation with the Arizona Corporation Commission on July 3, 1946, as a nonprofit corporation dealing in electrical energy. MEC filed its Articles of Conversion under the Electrical Cooperative Act of the State of Arizona on May 24, 1961, to become a cooperative. In 1986, MEC voted and filed to renew and continue its existence for another 25 years.

As of 2006, MEC had approximately 30,929 members, 36,855 usage meters, and 1,391 miles of line. The total retail energy sold was 763 million kWh. MEC has experienced significant load growth over the past few years along the Colorado River (Bullhead City) and east of the City of Kingman.

MEC provides retail electric service to the Reservation from distribution lines out of the Nelson Substation. MEC purchases its power from the Arizona Electric Power Cooperative (AEPCO)

To the extent that the activities of MEC affect the environment and the natural and cultural resources of the Reservation, MEC would be subject to federal and State environmental and cultural resources laws. Tribal laws (such as the *Hualapai Environmental Review Code* and the *Cultural Heritage Resources Ordinance*) by their terms, apply to the activities of MEC on the Reservation. However, there are uncertainties regarding the extent to which the Tribe could enforce its jurisdiction over MEC. These uncertainties result from federal court decisions in recent decades, including decisions limiting tribal sovereignty over the conduct of non-members on rights-of-way issues on trust lands.

4. Hualapai Tribe Strategy

4.a Objective

The objective of this report is to provide enough information and analysis to support a decision by the Council to adopt the Ordinance that would establish a TUA to provide cost effective and reliable electric service on the Reservation. The service area could be at GCW alone or could include GCW and the Peach Springs areas together. The purpose of the TUA would be to provide customers on the Reservation with more equitable, reliable, and quality electrical service than what is currently being provided and to offer these services at prices that are competitive with other suppliers serving similar types of rural areas. The TUA would achieve this mission by maintaining local control over electrical services, promoting long-term customer relationships, investing in new technology (as funding allows), and by developing efficiencies to serve Hualapai customers.

For GCW, the TUA would initially be responsible for the operations and maintenance of the solar and diesel generators and the associated distribution facilities up to the customer meter. The TUA would also investigate options for meeting GCW's future electricity requirements and establishing customer costs for providing additional service. The TUA would work to recover all costs through customer billing.

4.b Goals and Benefits to the TUA's Customers

By establishing a TUA on the Reservation, residents and commercial enterprises would ultimately receive more reliable electric service at competitive prices. The Tribe would also benefit from:

- **Local Presence** – The TUA office would be located in Peach Springs and staffed by local people, thereby providing local jobs and employment opportunities.
- **Convenience and Flexibility** – The TUA's plan would be to provide increased flexibility over time for customers to access information and utility services. In addition, a local TUA would work with its customers to establish the best billing approach for that customer such as levelized billing, pay-as-you-go card swipe systems, or scheduling particular billing days. Any and all of the potential programs would depend upon availability of funds.
- **Customer Service** – By being local, the TUA would personally know their customers and their needs. Over time response time for restoring power to those facilities controlled by the TUA could be reduced. In addition, over time more efficient service, such as same day turn-on service and restoration could be offered. The TUA would consider, as funds allow, employing technologies that increase efficiency and enhance service such as geographic information systems, automated meter reading, and supervisory control and data acquisition.

4.c Basis For Success

The success of the TUA would depend on how well it performs with regard to:

- Price
- Customer Service
- Customer Convenience
- Quality and Reliability of Service

Successful customer service can be assured through timely public communications that keep customers informed of services and that solicit customer feedback. Based on that feedback, the TUA would adjust its range of services and continue to improve operating efficiencies, which would translate into cost savings for its customers.

5. Characteristics of the TUA Service Area

There are two distinct areas that could be served by the TUA. One is GCW, which is located approximately 50 miles from Peach Springs. GCW is not electrical connected to the Peach Springs area. There is the potential to install approximately 6 – 10 meters in the GCW area. GCW electrical power would come from both a solar system and diesel generators. Currently the customers (which include the Grand Canyon West Corporation, the airport and residential customers) pay all the costs associated with delivering electric power.

The Peach Springs area is the main population center on the Reservation. There are approximately 430 retail meters in this area. Electric service is currently being provided by MEC.

6. The TUA Business and Operating Organization

6.a Overview

The report provides a reasonable and prudent discussion for establishing the needed staff, equipment, materials and technology to begin operating a TUA. Discussed below is the approach that the TUA could utilize to meet the objective of providing reliable service at reasonable prices, and having a local presence. The proposed activities mesh traditional utility practice with a view of implementing state-of-the-art approaches as funding would allow to support the plan to increase operating efficiencies and upgrade aging system conditions.

6.b Local Office

The TUA would establish a local office to administer the day-to-day operation in the Peach Springs area and to implement its customer service plan. In conjunction with the TUA staff, agreements would be in-place with third-party contractors for certain operations, maintenance and construction services. The local office could initially be integrated with an existing Tribal office. The Tribal employment policy would be utilized to ensure that qualified tribal members are given preference in TUA hiring. Staff would be added as required to balance customer needs and operating costs. All necessary equipment such as vehicles, a telephone system, desktop personal computers and printers, copiers and fax machines, computer software and office furniture would be obtained prior to startup and generally be housed in the TUA's local office. The TUA's local office would also contract for legal, consulting, advertising and accounting services as well as obtaining required insurance including liability insurance. Customer inquires, during normal business hours, would be handled by the local office. Outage response would be provided through the entity hired by the TUA to perform the construction and maintenance services.

6.c Equipment Requirements

The TUA's operational equipment would be obtained through a variety of relationships. This approach of outsourcing portions of the required equipment is consistent with contemporary approaches to obtain cost effective and technologically current equipment.

- The primary operational equipment requirements (rolling stock and electric system operational equipment) would be provided through a relationship with a third party that is contracted to provide Operation, Maintenance and Construction (OM&C) services to the TUA.

- Special maintenance and repair equipment that is not routinely required would be obtained through a contract with a third party that is contracted to provide Operation, Maintenance and Construction (OM&C) services to the TUA.
- Major equipment test gear would be contracted for instead of purchased.
- Computer hardware/software needed to support operations (e.g., customer information system, geographic information system, etc.) would be purchased as funding allows.
- Field communications equipment would be acquired by purchase or lease.

6.d Customer Services

In addition to the TUA having a local office and staff, there would be a need for additional staff to handle certain day-to-day functions as well as for services outside normal business hours. The TUA would explore various options relating to the need for day-to-day information technology solutions such as a customer call center, customer information system, billing and accounting system, outage management system, and a geographic information system that could be interconnected. The TUA would enter into an agreement with a third party or parties to provide the services listed above. The TUA has determined that during the initial 5-years, this approach would represent a sound business decision. It would provide the necessary service to its customers at a lower cost than if the TUA were to assume sole responsibility for the cost of such an effort due to economies of scale.

6.e Operations, Maintenance, and Construction (OM&C)

Overview 3rd Party Organization

With respect to the need to provide construction, engineering, operation and maintenance functions, the TUA would contract for these services until it becomes economically feasible to bring these functions in-house. As has been done by other tribal and corporate utilities in Arizona and across the nation, the TUA would enter into an agreement with a qualified and experienced provider of construction, operation, and maintenance services.

Based on the agreement, the services to be provided on a day-to-day basis would include transmission and distribution system management, operations, maintenance, engineering, and construction services necessary for the TUA to provide adequate and reliable retail services. The agreement would include responsibility for all facilities owned by the TUA including, but not limited to, transmission, overhead and underground distribution, street lighting systems, solar and wind electric systems, metering, and service lines. The following provides a list of responsibilities illustrative of the breadth of services that would be covered by such an agreement:

- System planning and engineering;
- Operations management;
- Line and service extensions;
- Meter installation and reading;
- Scheduled and unscheduled maintenance;
- Dispatch and outage restoration;
- Construction and construction management; and
- Management of material and equipment.

Coordination with the TUA staff working out of the local offices would include:

- Planning to define facility requirements to serve customers;
- Scheduling of construction and maintenance work;
- Preparing work orders for field installations and documenting actual installation and equipment/material costs;
- Performing line and service extensions;
- Providing construction management of work performed by contractors;
- Performing routine system maintenance;
- Managing and responding to outages;

- Managing equipment/material; and
- Performing meter reading;
- Reviewing contractor invoices for labor, parts, and materials.

It is planned that the agreement for OM&C services would be responsive to the level of requirement. Additional staff and/or services can be added as required.

The OM&C agreement would include typical construction and operational equipment including: bucket trucks; digger derricks; tilt bed, wire reel, and pole trailers; pickup trucks; and associated support equipment (air compressors, light plant, etc.).

Distribution and Maintenance Policies

The TUA and the OM&C contractor would work closely together to establish a comprehensive set of operational and maintenance policies following the formation of the TUA. These policies would be based on accepted industry practices and include operational and maintenance standards, safety procedures, reporting protocols, mapping standards, communication procedures, etc. The policies would assure effective and safe coordination of the TUA operations with MEC, the interconnecting utility. These policies would be reviewed with the interconnecting utility and comments solicited to insure compatibility with policies and system operations.

Dispatch and Service Restoration

A dispatch capability would be developed as part of the OM&C agreement to insure timely response to all service calls. Detail dispatch procedures would be developed following the formation of the TUA. A few general guidelines and approaches have been identified and would serve as the basis for the detail procedures.

- All calls would be routed to the OM&C contractor, dispatcher or designated serviceman.

- An integrated customer information system and geographic information system would be developed to identify critical customer information and expedite response.
- An effective communication system would be established with existing utilities that connect with the TUA's facilities to insure proper coordination of outage and operational actions.

Planning, Engineering and Construction Standards

An integrated set of planning, engineering and construction standards would be developed by the TUA following its formation.   These standards would be based on accepted utility industry practices and with a clear understanding of the needs of the interconnecting utilities to assure compatibility of design and construction standards. These standards would be reviewed with all interconnecting utilities and comments solicited to insure compatibility with policies and systems operation.

Material and Stores

The TUA would propose to have supply, inventory and warehousing of materials and equipment provided through the OM&C agreement. The TUA's OM&C agreement would provide for materials and equipment using a virtual warehousing and inventory concept for the construction, operation and maintenance of the system. The costs associated with the inventory and warehouse of all materials would be based upon the terms of the OM&C agreement. Some on-site storage area would likely be required for small parts, supplies, and routine maintenance items.

This approach to equipment and material supply is described as a "strategic, managed business relationship". This relationship would provide the TUA the following benefits:

- Access to a complete inventory of electric system equipment at competitive pricing;
- Access to local inventory;

- Material management efficiencies; and
- Work scheduling efficiencies.

A full range of electric system components would be provided under the arrangement including, but not limited to:

- Poles and pole top assemblies;
- Overhead and underground transformers;
- Sectionalization equipment;
- Conductor and related connectors;
- Cable and related termination equipment;
- Conduit and duct;
- Arrestors and protective equipment; and
- Meters and service assemblies.

The OM&C agreement would provide the TUA access to a wide range of distribution line equipment and materials, introduce efficiencies in material management, and at the same time minimize the impact on costs and essentially remove inventory risk.

Additional Resources

The need for additional resources to provide the above services would be met through several approaches. First, as previously discussed, the TUA would contract with a 3rd party for OM&C services. The 3rd party would purchase and install the necessary facilities for providing all services. In addition, the 3rd party would provide operation and maintenance services. According to standard electric utility practice, the 3rd party provider could contract with other providers for needed resources to meet service needs.

Power Supply Issues

The TUA would develop a power supply strategy that would provide reliable and cost competitive electricity to its customers. For the Peach Springs area, the

TUA would rely on its allocation from the Colorado River Storage Project (CRSP) plus additional resources that would be determined by a thorough evaluation by power supply experts. These experts would ascertain the most appropriate resources for the retail electric load to be served. By managing its power supply, the TUA would have inherent opportunities to examine such renewable resources as wind, solar, and biomass for meeting the Reservation's future needs. Renewable development can be fostered by TUA management based on its own resource decisions.

For GCW, the TUA would rely on the solar project and the diesel generators to provide the power needs of those customers.

A well-defined power supply arrangement would be in place to provide competitively priced power to the retail customers.

7. The TUA Services

The TUA, as part of its proposed plan, would offer customers the following services listed below. The services have been separated into those that are reflected in the current operation costs in the proforma, and those that are not since the services are customer or location specific. For the services reflected in the proforma, it was assumed that those cost components were included in the estimated operation, maintenance and construction costs.

Services whose costs are reflected in the proforma:

- Distribution system service;
- Meter reading; and
- Billing.

Services whose costs are not reflected in the proforma:

- Energy efficiency educational materials and workshops;
- Residential renewable energy systems program;

- Pay-as-you-go Card Swipe Metering; and
- Working with the Tribal Government for the establishment of programs for low income and elderly energy assistance.

The TUA would work to increase operating efficiencies and provide better value of service as perceived by the customer. Automation would be used as part of this effort. The TUA, as is economically justified, would make use of such activities as remote monitoring and control, load management and automated metering. The cost of some of the equipment when installed at the beginning is incrementally higher than equipment that is traditionally installed. Based on economic evaluation and customer need, the TUA would make business decisions as to the type of equipment to be installed. Upon the formation of the TUA and as part of the TUA's development of rates for approval by the Council, each of the services and associated costs would be fully developed and detailed to support the requested rate associated with each service.

The TUA would provide a menu of products and services to its customers. The TUA would provide traditional retail electric company services at rates and charges to be determined through traditional rate making procedures with final approval of all rates by the Council. Upon formation of the TUA, the TUA would develop the appropriate strategy, programs and specific operations and costs associated with implementation of these programs. While the TUA has generally included the costs of the base products and services, the actual cost for each additional product and service would not be developed until the TUA makes the determination that the service is required and would be cost effective to implement. Listed below are descriptions of examples of proposed retail electric services:

The TUA would provide retail electric service for the distribution of electricity from a point of interconnection on a transmission or distribution system to a point of connection (at secondary and primary voltage, with either single phase or three-phase service) with a retail customer. This service would include but not be limited to the following:

- Regulation and control of electricity in the distribution system;
- Planning, design, operation and maintenance of the distribution system facilities;
- System voltage and power continuity;
- Response to system outages;
- Approved public education and safety communications on distribution systems; and
- Line safety, including tree trimming.

The TUA would provide for the installation, maintenance, and control of standard street light fixtures. This service would include providing the energy for dusk to dawn operation and the relaying and fixture cleaning required to provide a quality roadway lighting service. This service could include a range of facilities outlined as follows:

- Placement of standard street light fixtures on existing poles;
- Placement of non-standard street light fixtures on existing poles;
- Placement of standard poles and standard street light fixtures; and
- Placement of non-standard poles and/or non-standard street light fixtures.

The installation, maintenance, and control of outdoor lighting not used for roadway illumination would be one of the products offered by the TUA. This service would include providing the fixture and associated controls to support dusk-to-dawn operation and the relaying and future cleaning required to provide quality security lighting service. The service would be available for customer owned outdoor lighting systems, roadway sign lighting and traffic control signals where all facilities are owned and maintained by the customers. Examples could include security; floodlighting, night lighting of recreational fields and miscellaneous facilities including rest rooms and concession stands. This service could include a range of:

- Lighting levels and types of lamps including high pressure sodium, mercury vapor, and metal halide; and
- Turn-on / turn-off control could be provided as an optional service.

Metering equipment and services that are not transmission and distribution utility metering system services could be included. Information relating to usage other than required for billing. Metering equipment and related non-billing services include recording meters to gather data for load research samples, studies, market research and other special studies.

The TUA would offer, over time, to its customers enhanced billing, historical usage information, and payment options as these capabilities are added to the TUA systems. These products would be designed to provide customers with alternative billing formats, expanded and meaningful account information, and payment options that meet the diverse needs of customers. These products would apply to all customers. Specific products could include the following:

- **Consolidated Billing**--would allow customers with multiple accounts to receive a single monthly Summary Bill for all locations in the TUA service area;
- **Billing for New Services**—would allow customers to avail themselves to financing plans for new equipment associated with providing electric service that can be consolidated on one statement with the customer’s electric bill.
- **Information Access**—via the Internet would allow customers access to their billing and usage history as well as explore strategies for energy conservation and renewable energy opportunities at a TUA web site.
- **Analytical Tools**—would be available on the TUA web site to allow customers the ability to analyze their consumption patterns. Basic levels of access and analysis would be free including graphing, temporal comparisons and trending. Customers could purchase higher levels of analysis tools that would include the ability to do energy audits and energy consumption comparisons with new efficient equipment.
- **Enhanced Billing Formats**—would be available for key accounts. This product would provide key account customers with a customized look and would further provide useful information including graphics showing comparisons with

previous periods and potentially a comparison with an energy usage index with similar businesses.

- **Payment Options**—would be customized in a manner that allows a customer to choose:
    - payment schedules—customer would be able to select due dates that coincide with their internal budgeting cycle;
    - alternative forms of payment--would include check drafting, credit card billing, and electronic funds transfer over the Internet or payment in local stores;
    - Card Swipe pay-as-you-go kiosks, and
    - quick payment discount.

The following service guarantees could be added, if authorized by the TUA Board and approved by Council, after the first few years of operation during which time the TUA would be focusing on reliable electric service, controlling operating expenses, and building operating reserves to ensure continuation of the enterprise:

- **Property damage**—The TUA could adopt a damage indemnification policy. In cases where a customer's property is damaged due to TUA work, the TUA would restore the property to its original condition before the work occurred. The TUA would either fix the damage or reimburse the customer for repairs by a third party.
- **Scheduled appointments**—The TUA personnel would arrive within an amount of time, to be determined, of a scheduled appointment, or would call to reschedule at least an hour before the appointment. If the TUA does not meet this commitment it could give the customer a billing credit.
- **Courteous service**—The TUA could guarantee that its personnel would provide courteous service. In the event a customer perceives that they have been treated poorly, the TUA would provide a number for the customer to call to report the incident and could be provided a billing credit.

- **Accurate billing and posting of payments**—The TUA could provide the customer a billing credit if it reads a meter inaccurately or incorrectly posts a customers payment.
- **Notification of planned service outage**—a 2-day warning for scheduled outages over 2 hours would be given. Failure to do so could result in the TUA providing the customer a billing credit.
- **Response to unplanned service outages**—The TUA would provide definitive information to the customer about expected restoration within a certain number of hours after initial notification. Otherwise, the customer could be given a billing credit.

In addition, the TUA would offer its customers a number of service options to be paid by the customer. These options would be designed to allow customers to enhance their reliability of service or lower their costs of services and enhance value and loyalty of these customers to the TUA. These products would apply primarily to larger commercial customers. Specific products could include, depending upon funding and operational restrictions:

- **Dual feed service**—In many cases, service reliability is critical. Where applicable, site-specific distribution changes such as dual feeds would be implemented under several pricing options to the customer, including long-term leasing or bundling into a long-term contract. For large customers, building of a new substation allowing transmission voltage delivery and pricing would be offered.
- **Equipment Lease/O&M services**—The TUA could lease facilities needed to provide electric service to customers under an appropriate lease arrangement. Customers would have the option of either maintaining the leased equipment or entering into an O&M arrangement with the TUA. Customers who own their own facilities would be offered O&M services under a defined product offering.
- **Distributed generation interconnection**—The TUA would develop engineering interconnection standards that identify the customer’s cost obligations.

At the request of the customer the TUA would cooperate with completing the needed interconnection arrangements.

Further, the TUA would offer customers, at the customers expense, with critical reliability or power quality requirements such services as described below. Customers requiring this level of on-site backup are most likely to be critical manufacturing or other critical loads. These products most likely would be applicable to larger customers. Specific products may include:

- **Reliability products**—Uninterruptible power supply (UPS) devices and outage detection/reporting devices, paid for by the customer, would be offered and installed for customer's who require a higher level of reliability. Where appropriate, these devices would be integrated with power quality equipment. Lease financing and O&M services would be available for customers who desire this service.
- **Power quality enhancements**—Power quality services would address harmonics, power factor, spikes and surges and other events that can upset sensitive electronic equipment. A comprehensive audit would be conducted in order to determine the design and specification for remedial products (e.g., surge suppressers, power conditioners, power factor correction, ground-fault detection, etc.) A report and a proposal with cost and schedule for installation of remedial measures would be provided to the customer.

The TUA anticipates that the above described products and services would allow customers to eventually avail themselves to conveniences that have not been available to them in the past.

8. Public Information

Immediately upon the formation of the TUA, the TUA would begin a public information campaign to make customers on the Reservation aware of the change. The TUA's initial campaign could include print as well as direct customer contacts.

9. Proforma – Five Year Financial Forecast

9.a Overview

The report presents the financial forecast or proforma of the initial five years of operation of the proposed TUA. (See Appendix D) A separate proforma was prepared for GCW and the Peach Springs area. Then a combined GCW-Peach Springs area proforma was prepared. This approach allows the Tribe to determine the economic feasibility of forming a TUA to operate GCW alone and the GCW and Peach Springs areas together.

The proforma statement is a forecast or estimate of utility operations in the future. It is intended to demonstrate whether the proposed project, to form a TUA, is economically feasible and would support the suggested goals of the TUA. The role of the proforma statement is to demonstrate that the proposed TUA would be able to provide safe and reliable service at reasonable, fair, competitive, and hopefully, over time, lower cost than MEC to customers on the Reservation at both the Peach Springs area and the GCW area. The proforma statement is a mathematical expression intended to demonstrate that the TUA, as proposed, would provide for the necessary financial, professional, technical and managerial resources in order to provide safe and reliable service at a competitive cost. Appendix N displays a flow diagram of the components included in the proforma and the general relationships of the components. The proforma contains the following items and a more detailed discussion of each item follows:

- Revenue and Customer Load Forecast;
- Purchased Power Costs;
- Transmission and Distribution Delivery Costs;
- Operation, Maintenance & Construction Costs;
- Administrative & General Costs;
- Revenue Requirements;

- Cash Flow Analysis; and
- Capitalization Requirements.

The proforma statements supporting the formation of a TUA to serve both the Peach Springs and GCW areas are conservative; yet indicate that the TUA would be able to provide reliable services at prices, terms and conditions attractive to existing and new customers. For example, the proforma statements assume that the TUA would build new distribution facilities and install new meters for its customers. The proforma also reflects a plan to use MEC's transmission, substation and distribution lines to provide for delivery of power to the TUA's customers.

9.b Revenue and Customer Load Forecast

A revenue and customer load forecast was prepared separately for the Peach Springs and GCW areas. Below is a brief discussion of the data and assumptions used in the development of the forecasts.

Peach Springs Area

MEC provided the Tribe with customer data by rate type for the period July 2004 through June 2006. The data included number of customers, monthly energy use, billing charges, and rate type. This information was combined by rate type to develop a base test year customer forecast. For purposes of this study the base test year forecast was the actual data for July through December 2005 and January through June 2006. The base test year energy and revenue were escalated at 1.0% per year. During the study period it was also assumed that there were no rate increases, such that the average cost per kWh remained constant throughout the study period or at the same level as was being charged by MEC in 2006. Finally, where demand data was not available estimated load factors were used a shown below:

Assumed Residential Load Factor =	40%
Assumed Commercial Load Factor =	50%

The average annual cents per kWh for MEC customers based on 2006 rates is shown below:

Annual Average Cost of Energy MEC 2006 Effective Rates cents / kWh	
Customer Type	**cents / kWh**
Residential	9.7812
Small Commercial with Demand	9.4789
Small Commercial with Energy	9.1685
Large Commercial	7.2734
Peach Springs Area Combined	9.2102

Grand Canyon West (GCW)

Daystar Consulting, LLC (Daystar) provided estimates of customer data for the GCW area. The data included number of customers and monthly energy. This information was combined by to develop a base test year customer forecast. For purposes of this study the base test year forecast was the data provided by Daystar. The base test year energy was escalated at 2.0% per year. GCW does not have any rate structure in place as the energy provided comes from diesel generators. For purposes of this study a proxy rate was developed such that the annual average cents per kWh would just recover the operating costs. Note that any additional Administrative and General (A&G) costs associated with the management of the TUA were assumed to be part of the Peach Springs area A&G costs. During the study period it was assumed that the rates increased to recover the increase in operating costs that were assumed to increase at 3.0% per year, driven primarily by the cost of diesel fuel. Finally, estimated load factors to determine demand were used as shown below:

Assumed Residential Load Factor =	40.0%
Assumed Commercial Load Factor =	50.4%

The average annual dollars per kWh charged to the GCW customers is shown below:

It should be noted that the separate load forecasts were not combined to determine the purchase power costs. Rather, purchased power costs were determined separately for each area, Peach Springs and Grand Canyon West, as is described more completely in the section on purchased power.

	E	F
102	Grand Canyon West	
103	Estimated Annual Average Retail Rate	
104	cents/kWh	
105	**Year**	**cents/kWh**
106	2007	50.60000
107	2008	52.10000
108	2009	53.60000
109	2010	55.10000
110	2011	56.70000
111		

9.c **Purchased Power Costs**

The power resources available to each area are unique. A discussion of the power resources available to each area follows below.

Peach Springs Area

The Peach Springs area is interconnected through MEC's Nelson Substation to the high voltage transmission grid. Thus, the Peach Springs area can and does receive power over the interconnected transmission grid to serve load. There were 3 resources identified as being available to serve the Reservation load in the Peach Springs area. Those resources include: 1) the Tribe's allocation from the Salt Lake City Area Integrated Projects (SLCAIP or Colorado River Storage Projects (CRSP)); 2) wind generated power; and 3) power purchased from third parties.

The allocation of the CRSP power was initiated by the Western Area Power Administration (WAPA) (a power marketing agency for the U.S. Department of Energy). WAPA published a Federal Register Notice on September 8, 1999, which sought applicants for hydroelectric power from the Colorado River Storage Project (CRSP) to begin October 1, 2004.

Each entity interested in receiving an allocation was required to submit an application by June 8, 2000. The proposed allocations of power were published on June 15, 2001. The final allocations were published in the February 4, 2002 Federal Register Notice. Based on the Hualapai Tribe's application, the final allocation for the Tribe is shown below:

Winter Seasonal Energy (kWh)	Summer Seasonal Energy (kWh)	Winter Seasonal CROD (kW)	Summer Seasonal CROD (kW)
1,411,736	1,357,114	609	625

The Tribe received an allocation of both capacity and energy. The existing contract specifics the maximum contract delivery amounts. However, the actual available amounts of capacity and energy available at any point in the year is dependent on both the hydrology of the Colorado River and any constraints imposed on the operation of the power generation facility. Currently, in addition to low water flows, ongoing EIS studies have reduced the available output from Glen Canyon

Dam. Prior to each season, WAPA issues a schedule showing available capacity and energy per month.

The existing contract allows the Tribe the ability to make supplemental purchases of additional power equal to the difference between the maximum contract delivery amounts and the available delivery amounts. Once the seasonal schedule has been completed, the TUA would be required to provide an hourly schedule of how the allocation should be delivered. Once the schedule is submitted, WAPA would deliver the power to the TUA's designated delivery point(s).

It is important to note that CRSP power cannot be resold above cost to another CRSP contractor and cannot be resold to a non-preference entity. The TUA can, however, use the power to provide retail electric service at rates that allow for a reasonable return on its investment. In order to provide retail electric service and take physical delivery of the CRSP power, the TUA would need to purchase or lease the distribution facilities on the Reservation.

The current cost of CRSP power is shown below. In addition to the charge for power, WAPA passes through any transmission costs incurred to get to the TUA's delivery point(s). It should be noted that the contract is a "take or pay" arrangement, obligating the TUA to pay for its monthly allocation whether it can use the entire amount or not. There are ways to mitigate the "take or pay" requirement, such as entering into a pooling arrangement with other CRSP contractors**.** Under a pooling arrangement, the TUA could allow another CRSP customer to use and pay for any excess power from the Tribe's allocation. The TUA and the other CRSP customer would notify WAPA of the monthly reallocation so that the appropriate users are charged accordingly.

Salt Lake City Area Integrated Projects Firm Power Rate (SLIP-F6) (Effective October 1, 2005 and Expires September 30, 2024 unless otherwise changed)	
Capacity	**$4.43 per kW per month**
Energy	**$10.43 per MWh**
Transmission	**Actual cost based on transmission path**

The Tribe entered into a Benefit Credit Agreement with the Navajo Tribal Utility Authority (NTUA). This agreement provided Hualapai with the benefit of the CRSP allocation, without having to take physical delivery of the power. Under the terms of the agreement, NTUA pays to the Tribe approximately $ 3,000 per month.

It is assumed for this study that the Tribe would terminate its NTUA agreement and would elect to receive physical delivery of its CRSP allocation. In addition, it is assumed that Western Replacement Power as provided for under the CRSP contract would be purchased, as required, to meet load.

Another possible resource option available to the TUA could come from the development and construction of a wind turbine in the Peach Springs area. The wind turbine would be approximately 1.5 MW. On January 11, 2007, Richard Simon of Windots provided estimates of the amount of energy the wind turbine could produce. It is assumed that the energy produced by the wind turbine would be added to the CRSP power to meet customer loads. The cost for operations and maintenance of the wind turbine is estimated at $0.065 /kWh with an increase of 2.0% per year.

The capital cost for the 1.5 MW wind turbine was estimated to be $2,250,000. It is assumed that the construction of the wind turbines would be financed for twenty-years at an interest rate of 5.5%. Should the TUA enter into an arrangement to sell both the energy and green credits of the wind project, it was assumed that, at a minimum, the value of that sale would be equal to the cost of supplemental power necessary to replace the wind turbine energy.

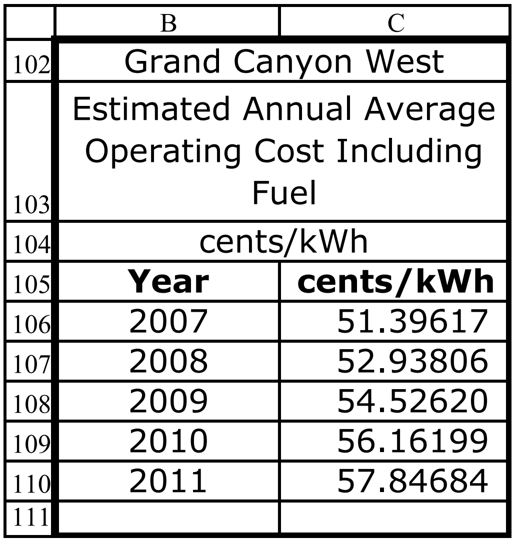
Third party resource purchases could be made to meet all remaining load requirements in the Peach Springs area. While an exact seller has not been identified, a proxy price based upon the current market is assumed in this study. This estimated rate is $0.065 /kWh plus scheduling and delivery costs with an increase of 2% per year.

Grand Canyon West

Grand Canyon West (GCW) is located in an isolated area and is not connected to any transmission or distribution grid. Currently the power needs of the GCW area are meet by diesel generators. In 2004, the Tribe received a grant from the U.S. Department of Agriculture to install a solar power system and distribution facilities at GCW to supplement the generator power. The current plan to serve the GCW area is to install approximately 33 kW of solar and 100 kW of diesel generation. The estimated operating costs are increased at 3.0% per year as shown below. The costs include diesel fuel and labor and materials for maintaining the solar system and generators.

9.d Transmission and Distribution Delivery Cost

The Peach Springs area is served from the grid transmission system, while



	B	C
102	Grand Canyon West	
103	Estimated Annual Average Operating Cost Including Fuel	
104	cents/kWh	
105	**Year**	**cents/kWh**
106	2007	51.39617
107	2008	52.93806
108	2009	54.52620
109	2010	56.16199
110	2011	57.84684
111		

Grand Canyon West is completely off-grid. The following discussion describes the power transmission resources available to each area.

Peach Springs Area

The Peach Springs area is connected to the high-voltage transmission grid through MEC's Nelson Substation, which is located approximately 7 miles southeast of Peach Springs. It is anticipated that power would be delivered over one of the high voltage transmission lines serving the Round Valley Substation, which is located approximately 36 miles south of the Nelson Substation. From the Round Valley Substation power would be delivered, as is currently done, over the MEC 69 kV line to Nelson Substation. From the Nelson Substation power would be delivered, as is currently done, over MEC's 25 kV system to newly established metered 25 kV delivery points. To create the new metered delivery points could require some reconfiguration of the existing MEC distribution facilities that currently serve both the on and off Reservation loads.

For purposes of the analyses it was assumed that the TUA would purchase ancillary services to deliver power to the Nelson Substation. The ancillary services and associated assumed charges for purposes of this analysis are listed below.

Ancillary Services

	Description	Charge	
	Scheduling, System Control & Dispatch Service	0.08	per kW-month * PS Peak At Time of MEC Peak
	Reactive Supply & Voltage Control from Generation Sources Service	0.10	per kW-month * PS Peak At Time of MEC Peak
	Regulation & Frequency Response Service	0.00355	per kWh * 3.99%
	Energy Imbalance Service		
	Operating Reserve/Spinning Reserve Service	0.00783	per kWh * 3.5%
	Operating Reserve/Supplemental Reserve Service	0.01133	per kWh * 3.5%

In addition to the high voltage transmission services, the TUA would need to purchase and pay MEC for wheeling across its 69 kV and 25 kV systems. For the cost analysis in this study, it was assumed that the TUA would pay MEC $2.50 /kW plus 4.0% losses for this wheeling service.

Grand Canyon West

Grand Canyon West (GCW) is located in an isolated area and is not interconnected to any electrical transmission or distribution grid. All the power needed to serve load is generated locally with diesel generators and a solar energy system at GCW and is connected directly to the load. There are no additional transmission or distribution wheeling costs for delivery of this power.

9.e Operation, Maintenance & Construction (OM&C) Costs

The scope of the TUA's operation, maintenance, and construction activities would not be large enough to justify the TUA having its own lineman and line trucks. It is assumed in this plan that the TUA would contract with a third party for OM&C

services. It is not unusual in the electric utility industry for utilities to use outside contractors for such services. Although the electrical distribution systems for GCW and Peach Springs are separate, the OM&C requirements are similar for both areas. The cost analysis in this plan includes the projected OM&C costs for GCW alone and for GCW and Peach Springs together.

9.f Administrative & General Costs

Even though Peach Springs and GCW are on separate electrical systems oversight and administration of the utility functions can be managed as a single entity. For this report it was assumed that the TUA would require only one full-time administrator with all other labor to be provided through 3rd party contracts, as needed, such that the administrator and 3rd party contracts would provide the following activities:

- Meter reading;
- Billing;
- Contract Administration;
- Power scheduling; and
- Customer service

However, the A&G costs were developed assuming GCW alone and then with GCW and Peach Springs together. Should GCW and Peach Springs be operated together, by managing the two systems as one the associated costs can be shared while improving the utilization of the manpower.

9.g Revenue Requirement Analysis

The revenue requirement analysis in this report compares the estimated income from the sale of power to end-use customers with the estimated expenses associated with providing electric service for GCW alone and for GCW and Peach Springs together over a period of five years. This includes the annual forecasted costs for.

- Purchased Power;

- Transmission and Distribution Delivery;
- Operations and Maintenance (O&M) Contracts;
- Administrative and General (A&G) Expenses; and
- Capital Repayment – Debt Service.

According to this analysis, in the "GCW only" scenario, revenues will be sufficient for covering costs. The analysis for GCW and Peach Springs together indicates that, to cover costs, a rate increase to the end-customers would be required.

9.h **Capitalization Requirements**

There will be no additional capital investment required for the "GCW only" scenario as funding was provided through a grant. Eventually, the GCW system may require upgrades as new customers are added. The TUA would evaluate the need for additional capital investments and adjust rates such that additional revenues from energy sales to those customers would be able to cover the additional capital investment costs.

The GCW and Peach Springs scenario will require a commitment estimated at $210,000 to purchase the MEC distribution facilities in the Peach Springs area. It was assumed that this investment would be financed over thirty-years at an interest rate of 8.0%. For the remaining four-years of the analysis, it was estimated that $200,000 per year would be spent on additional capital improvements. The additional capital improvements would be financed over thirty-years at an interest rate of 8.0%. The revenue analysis reflects the annual debt service associated with each capital investment loan.

For the sensitivity case of installing a wind turbine, the estimated cost of the wind turbine is $2,250,000. It was assumed that the wind turbine would be financed for twenty-years at 5.5%.

It should be notes that if the TUA can obtain grants for any of the capital requirements, this would reduce the annual debt service and reduce the need for additional revenues.

9.i Proforma Results

Based upon the above discussion of the input data and assumptions, a Base Case proforma was prepared for GCW alone and for GCW and Peach Springs together. A discussion of the results of the GCW Base Case proforma and the GCW and Peach Springs together Base Case proforma follows. In addition, a sensitivity analysis referred to as Case A included the installation of the wind turbine at Peach Springs and a discussion of the Case A results also follows.

Grand Canyon West

The result of the GCW Base Case proforma is shown on Table 1 on the next page. The GCW Base Case includes the use of the existing diesel system and the installation of the solar project as provided for in the grant. The user rates assumed in the proforma are based on what GCW customers are currently paying to produce energy with the diesel generators. The results show that revenues from customer charges can cover all costs.

1

	A	B	C	D	E	F
1	**Table 1 - GCW Base Case Proforma Summary**					
2		**Annual Summary**				
3		**2007**	**2008**	**2009**	**2010**	**2011**
4						
5	**Energy Sales At Meter**					
6						
7	Total GCW Energy Sales At Meter (kWh)	626,076	638,598	651,369	664,397	677,685
8			12,522	12,772	13,027	13,288
9	Cash Flow from Operations	**$ 316,794**	**$ 332,709**	**$ 349,134**	**$ 366,083**	**$ 384,247**
10			$ 15,915	$ 16,425	$ 16,949	$ 18,165
11						
12	**Disbursements**					
13	**GCW Purchase Power Costs**					
14	CRSP Cost	$ -	$ -	$ -	$ -	$ -
15	Solar Power Cost	$ -	$ -	$ -	$ -	$ -
16	Supplemental Power Cost	$ 291,711	$ 307,226	$ 323,549	$ 340,721	$ 358,786
17	**Total GCW Purchase Power Costs**	**$ 291,711**	**$ 307,226**	**$ 323,549**	**$ 340,721**	**$ 358,786**
18						
19	**GCW Power Delivery Costs**		$ 15,515	$ 16,323	$ 17,172	$ 18,065
20	Transmission Delivery Cost	$ -	$ -	$ -	$ -	$ -
21	12 kV Distribution Delivery Cost	$ -	$ -	$ -	$ -	$ -
22	**Total GCW Power Delivery Costs**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
23			$ -	$ -	$ -	$ -
24	**Total Purchase Power & Power Delivery Costs**	**$ 291,711**	**$ 307,226**	**$ 323,549**	**$ 340,721**	**$ 358,786**
25	**Average Cost for Energy Sales At Retail Meter - cents/kWh**	**$ 46.59**	**$ 48.11**	**$ 49.67**	**$ 51.28**	**$ 52.94**
26						
27	**Net Profit / (Loss)**	**$ 25,084**	**$ 25,483**	**$ 25,585**	**$ 25,361**	**$ 25,461**
28			$ 400	$ 102	$ (224)	$ 99
29	**GCW Distribution System O,M&C**					
30	O&M	$ -	$ -	$ -	$ -	$ -
31	Maintenance Premiums	$ -	$ -	$ -	$ -	$ -
32	Materials	$ 25,000.00	$ 25,000.00	$ 25,000.00	$ 25,000.00	$ 25,000.00
33	Power Factor Penalties	$ -	$ -	$ -	$ -	$ -
34	Customer Service / Call Center	$ -	$ -	$ -	$ -	$ -
35	Meter Reading:	$ -	$ -	$ -	$ -	$ -
36	Training Services:	$ -	$ -	$ -	$ -	$ -
37	Billing	$ -	$ -	$ -	$ -	$ -
38	**GCW OM&C Cost subtotal**	**$ 25,000**	**$ 25,000**	**$ 25,000**	**$ 25,000**	**$ 25,000**
39						
40	**Net Profit / (Loss)**	**$ 84**	**$ 483**	**$ 585**	**$ 361**	**$ 461**
41			$ 400	$ 102	$ (224)	$ 99
42	**Administrative & General:**	**Included As Part of Cost of Power**				
43	Rent	$ -	$ -	$ -	$ -	$ -
44	Utilities (Water & Electric)	$ -	$ -	$ -	$ -	$ -
45	Telephone	$ -	$ -	$ -	$ -	$ -
46	Office Maintenance (Repairs, Exterminators, Jan	$ -	$ -	$ -	$ -	$ -
47	Salaries & Benefits	$ -	$ -	$ -	$ -	$ -
48	Board Costs	$ -	$ -	$ -	$ -	$ -
49	Travel	$ -	$ -	$ -	$ -	$ -
50	Training	$ -	$ -	$ -	$ -	$ -
51	Office Materials & Supplies	$ -	$ -	$ -	$ -	$ -
52	Auto (Insurance, Fuel & Mainteance)	$ -	$ -	$ -	$ -	$ -
53	Industry Experts	$ -	$ -	$ -	$ -	$ -
54	Accounting	$ -	$ -	$ -	$ -	$ -
55	Legal	$ -	$ -	$ -	$ -	$ -
56	Misc(Payroll Service, Advertising, Bank Charges,	$ -	$ -	$ -	$ -	$ -
57	**A&G Cost subtotal**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
58						
59	**Net Profit / (Loss)**	**$ 84**	**$ 483**	**$ 585**	**$ 361**	**$ 461**
60			$ 400	$ 102	$ (224)	$ 99
61	**Reserves/Contingencies**	**Included As Part of Peach Springs A&G Costs**				
62	**Reserves/Contingencies subtotal**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
63						
64	**Net Profit / (Loss)**	**$ 84**	**$ 483**	**$ 585**	**$ 361**	**$ 461**
65			$ 400	$ 102	$ (224)	$ 99
66						

Grand Canyon West and Peach Springs Together

The result of the GCW & Peach Springs Base Case proforma is shown on Table 2 on the next page. The results as summarized on Table 3 show that existing MEC rates charged to Peach Springs' customers would not provide sufficient revenue for covering all costs. Therefore, an initial increase in revenues of approximately $47,408 or 5.47 % would be needed followed by increases of between 2 – 3% each year thereafter as shown on Table 3.

The results of the analysis with the wind turbine, referred to as GCW & Peach Springs Case A is shown on Table 4. With the wind turbines the results show that existing MEC rates charged to Peach Springs customers would not provide sufficient revenue for covering all costs. Therefore, an initial rate increase of approximately $241,415 or 27.87% would be necessary followed by increases of approximately 2 % each year thereafter as shown on Table 5. The need for additional revenue could be reduced if the wind turbine project was funded through a grant.

The need for additional revenues in the future may also be impacted by changes in such other factors as customer growth, purchased power costs and O&M costs.

1

	A	B	C	D	E	F
1	**Table 2 - PS & GCW Base Case Proforma Summary**					
2				**Annual Summary**		
3		**2007**	**2008**	**2009**	**2010**	**2011**
4						
5	**Energy Sales At Meter**					
6						
7	Total Peach Springs Energy Sales At Meter (kWh)	5,963,604	6,178,898	6,240,687	6,303,093	6,366,124
8	Total GCW Energy Sales At Meter (kWh)	626,076	638,598	651,369	664,397	677,685
9	**Total Energy Sales - kWh**	6,589,680	6,817,495	6,892,056	6,967,490	7,043,809
10						
11	**Revenue From Sales**					
12						
13	Total PS Revenue From Energy Sales - $	$ 549,277	$ 568,966	$ 574,656	$ 580,403	$ 586,207
14	Total GCW Revenue From Energy Sales - $	$ 316,794	$ 332,709	$ 349,134	$ 366,083	$ 384,247
15	**Total Revenue - $**	**$ 866,071**	**$ 901,676**	**$ 923,790**	**$ 946,485**	**$ 970,454**
16						
17	**Disbursements**					
18	**Purchased Power Costs**					
19	**PS Purchase Power Costs**					
20	CRSP Cost	$ 197,310	$ 198,620	$ 199,956	$ 201,319	$ 202,709
21	Renewable Power Cost	$ -	$ -	$ -	$ -	$ -
22	Supplemental Power Cost	$ 111,480	$ 132,371	$ 139,880	$ 147,685	$ 155,797
23	**Total PS Purchase Power Costs**	**$ 308,789**	**$ 330,991**	**$ 339,836**	**$ 349,004**	**$ 358,506**
24						
25	**GCW Purchase Power Costs**					
26	CRSP Cost	$ -	$ -	$ -	$ -	$ -
27	Solar Power Cost	$ -	$ -	$ -	$ -	$ -
28	Supplemental Power Cost	$ 291,711	$ 307,226	$ 323,549	$ 340,721	$ 358,786
29	**Total GCW Purchase Power Costs**	**$ 291,711**	**$ 307,226**	**$ 323,549**	**$ 340,721**	**$ 358,786**
30	**Total Purchased Power Cost - $**	**$ 600,500**	**$ 638,217**	**$ 663,385**	**$ 689,725**	**$ 717,293**
31						
32	**Power Delivery Costs**					
33	**PS Power Delivery Costs**		$ 22,202	$ 8,844	$ 9,168	$ 9,503
34	Transmission Delivery Cost	$ 26,630	$ 27,110	$ 27,202	$ 27,294	$ 27,387
35	12 kV Distribution Delivery Cost	$ 73,555	$ 79,411	$ 80,631	$ 81,881	$ 83,163
36	**Total PS Power Delivery Costs**	**$ 100,185**	**$ 106,521**	**$ 107,832**	**$ 109,175**	**$ 110,550**
37						
38	**GCW Power Delivery Costs**					
39	Transmission Delivery Cost	$ -	$ -	$ -	$ -	$ -
40	12 kV Distribution Delivery Cost	$ -	$ -	$ -	$ -	$ -
41	**Total GCW Power Delivery Costs**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
42	**Total Power Delivery Cost - $**	**$ 100,185**	**$ 106,521**	**$ 107,832**	**$ 109,175**	**$ 110,550**
43						
44	**Total Purchase Power & Power Delivery Costs**	**$ 700,685**	**$ 744,738**	**$ 771,217**	**$ 798,900**	**$ 827,843**
45						
46	**Net Profit / (Loss)**	**$ 165,386**	**$ 156,938**	**$ 152,573**	**$ 147,585**	**$ 142,611**

2

	A	B	C	D	E	F
48	**Table 2 - PS & GCW Base Case Proforma Summary**					
49				**Annual Summary**		
50		**$ 2,007**	**$ 2,008**	**$ 2,009**	**$ 2,010**	**$ 2,011**
51						
52	**Distribution System O,M&C**					
53	**PS Distribution System O,M&C**					
54	O&M	$ 25,787	$ 29,506	$ 29,907	$ 30,206	$ 30,508
55	Maintenance Premiums	$ -	$ -	$ -	$ -	$ -
56	Materials	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000
57	0	$ -	$ -	$ -	$ -	$ -
58	Customer Service / Call Center	$ -	$ -	$ -	$ -	$ -
59	Meter Reading:	$ 11,238	$ 11,355	$ 11,462	$ 11,569	$ 11,677
60	Training Services:	$ -	$ -	$ -	$ -	$ -
61	Billing	$ -	$ -	$ -	$ -	$ -
62	**PS OM&C Cost subtotal**	**$ 57,025**	**$ 60,862**	**$ 61,368**	**$ 61,775**	**$ 62,185**
63						
64	**GCW Distribution System O,M&C**					
65	O&M	$ -	$ -	$ -	$ -	$ -
66	Maintenance Premiums	$ -	$ -	$ -	$ -	$ -
67	Materials	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000
68	Power Factor Penalties	$ -	$ -	$ -	$ -	$ -
69	Customer Service / Call Center	$ -	$ -	$ -	$ -	$ -
70	Meter Reading:	$ -	$ -	$ -	$ -	$ -
71	Training Services:	$ -	$ -	$ -	$ -	$ -
72	Billing	$ -	$ -	$ -	$ -	$ -
73	**GCW OM&C Cost subtotal**	**$ 25,000**	**$ 25,000**	**$ 25,000**	**$ 25,000**	**$ 25,000**
74	**Total Distribution System O,M&C**	**$ 82,025**	**$ 85,862**	**$ 86,368**	**$ 86,775**	**$ 87,185**
75						
76	**Net Profit / (Loss)**	**$ 83,360**	**$ 71,076**	**$ 66,205**	**$ 60,811**	**$ 55,426**
77						
78	**PS & GCW Administrative & General:**					
79	Rent	$ -	$ -	$ -	$ -	$ -
80	Utilities (Water & Electric)	$ -	$ -	$ -	$ -	$ -
81	Telephone	$ 1,200	$ 1,224	$ 1,248	$ 1,273	$ 1,299
82	Office Maintenance (Repairs, Exterminators, Janitor &	$ -	$ -	$ -	$ -	$ -
83	Salaries & Benefits	$ 60,000	$ 61,200	$ 62,424	$ 63,672	$ 64,946
84	Board Costs	$ -	$ -	$ -	$ -	$ -
85	Travel	$ -	$ -	$ -	$ -	$ -
86	Training	$ -	$ -	$ -	$ -	$ -
87	Office Materials & Supplies	$ 6,200	$ 6,324	$ 6,450	$ 6,579	$ 6,711
88	Auto (Insurance, Fuel & Mainteance)	$ -	$ -	$ -	$ -	$ -
89	Industry Experts	$ 30,000	$ 30,600	$ 31,212	$ 31,836	$ 32,473
90	Accounting	$ 5,000	$ 5,100	$ 5,202	$ 5,306	$ 5,412
91	Legal	$ 5,000	$ 5,100	$ 5,202	$ 5,306	$ 5,412
92	Misc(Payroll Service, Advertising, Bank Charges, dona	$ -	$ -	$ -	$ -	$ -
93	**PS & GCW A&G Cost subtotal**	**$ 107,400**	**$ 109,548**	**$ 111,739**	**$ 113,974**	**$ 116,253**
94						
95	**Net Profit / (Loss)**	**$ (24,040)**	**$ (38,472)**	**$ (45,534)**	**$ (53,163)**	**$ (60,827)**
96						
97						
98	**PS Debt Service**					
99	**PS Debt Service Total (P&I)**	**$ 18,368**	**$ 35,862**	**$ 53,356**	**$ 70,850**	**$ 88,343**
100						
101	**Net Profit / (Loss)**	**$ (42,408)**	**$ (74,334)**	**$ (98,890)**	**$ (124,013)**	**$ (149,170)**
102						
103	**PS & GCW Reserves/Contingencies**					
104	**Reserves/Contingencies subtotal**	**$ 5,000**	**$ 5,100**	**$ 5,202**	**$ 5,306**	**$ 5,412**
105						
106	**Net Profit / (Loss)**	**$ (47,408)**	**$ (79,434)**	**$ (104,092)**	**$ (129,319)**	**$ (154,583)**

	A	B	C	D	E	F
109	**Table 3 - PS & GCW Base Case Proforma Summary**					
110		**Annual Summary**				
111		**2007**	**2008**	**2009**	**2010**	**2011**
112	Total Revenue - $	$ 866,071	$ 901,676	$ 923,790	$ 946,485	$ 970,454
113	Plus Revenue Adjustment From Prior Year- $	$ -	$ 47,408	$ 79,434	$ 104,092	$ 129,319
114	Net Projected Revenue - $	$ 866,071	$ 949,084	$ 1,003,224	$ 1,050,577	$ 1,099,773
115	Needed Revenue - $	$ 913,479	$ 981,110	$ 1,027,882	$ 1,075,804	$ 1,125,037
116	Plus Current Year Adjustment - $	$ 47,408	$ 32,026	$ 24,658	$ 25,227	$ 25,264
117	Adjusted Revenue - $	$ 913,479	$ 981,110	$ 1,027,882	$ 1,075,804	$ 1,125,037
118	% Yearly Increase	5.47%	3.37%	2.46%	2.40%	2.30%

1

2

	A	B	C	D	E	F
1	**Table 4 - PS & GCW Case A Proforma Summary**					
2				**Annual Summary**		
3		**2007**	**2008**	**2009**	**2010**	**2011**
4						
5	**Energy Sales At Meter**					
6						
7	Total Peach Springs Energy Sales At Meter (kWh)	5,963,604	6,178,898	6,240,687	6,303,093	6,366,124
8	Total GCW Energy Sales At Meter (kWh)	626,076	638,598	651,369	664,397	677,685
9	**Total Energy Sales - kWh**	6,589,680	6,817,495	6,892,056	6,967,490	7,043,809
10						
11	**Revenue From Sales**					
12						
13	Total PS Revenue From Energy Sales - $	$ 549,277	$ 568,966	$ 574,656	$ 580,403	$ 586,207
14	Total GCW Revenue From Energy Sales - $	$ 316,794	$ 332,709	$ 349,134	$ 366,083	$ 384,247
15	**Total Revenue - $**	**$ 866,071**	**$ 901,676**	**$ 923,790**	**$ 946,485**	**$ 970,454**
16						
17	**Disbursements**					
18	**Purchased Power Costs**					
19	**PS Purchase Power Costs**					
20	CRSP Cost	$ 103,258	$ 112,681	$ 116,830	$ 120,827	$ 124,777
21	Renewable Power Cost	$ 201,500	$ 205,530	$ 209,641	$ 213,833	$ 218,110
22	Supplemental Power Cost	$ 129	$ 1,923	$ 2,243	$ 2,849	$ 3,622
23	**Total PS Purchase Power Costs**	**$ 304,887**	**$ 320,134**	**$ 328,713**	**$ 337,509**	**$ 346,508**
24						
25	**GCW Purchase Power Costs**					
26	CRSP Cost	$ -	$ -	$ -	$ -	$ -
27	Solar Power Cost	$ -	$ -	$ -	$ -	$ -
28	Supplemental Power Cost	$ 291,711	$ 307,226	$ 323,549	$ 340,721	$ 358,786
29	**Total GCW Purchase Power Costs**	**$ 291,711**	**$ 307,226**	**$ 323,549**	**$ 340,721**	**$ 358,786**
30	**Total Purchased Power Cost - $**	**$ 596,597**	**$ 627,360**	**$ 652,262**	**$ 678,230**	**$ 705,295**
31						
32	**Power Delivery Costs**					
33	**PS Power Delivery Costs**		$ 15,247	$ 8,579	$ 8,795	$ 9,000
34	Transmission Delivery Cost	$ 26,961	$ 27,288	$ 27,361	$ 27,435	$ 27,509
35	12 kV Distribution Delivery Cost	$ 78,586	$ 81,771	$ 82,719	$ 83,686	$ 84,672
36	**Total PS Power Delivery Costs**	**$ 105,547**	**$ 109,060**	**$ 110,080**	**$ 111,121**	**$ 112,181**
37						
38	**GCW Power Delivery Costs**					
39	Transmission Delivery Cost	$ -	$ -	$ -	$ -	$ -
40	12 kV Distribution Delivery Cost	$ -	$ -	$ -	$ -	$ -
41	**Total GCW Power Delivery Costs**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
42	**Total Power Delivery Cost - $**	**$ 105,547**	**$ 109,060**	**$ 110,080**	**$ 111,121**	**$ 112,181**
43						
44	**Total Purchase Power & Power Delivery Costs**	**$ 702,144**	**$ 736,420**	**$ 762,342**	**$ 789,350**	**$ 817,476**
45						
46	**Net Profit / (Loss)**	**$ 163,927**	**$ 165,256**	**$ 161,448**	**$ 157,135**	**$ 152,978**

	A	B	C	D	E	F
48	Table 4 - PS & GCW Case A Proforma Summary					
49		Annual Summary				
50		**$ 2,007**	**$ 2,008**	**$ 2,009**	**$ 2,010**	**$ 2,011**
51						
52	**Distribution System O,M&C**					
53	**PS Distribution System O,M&C**					
54	O&M	$ 25,442	$ 29,131	$ 29,532	$ 29,831	$ 30,133
55	Maintenance Premiums	$ -	$ -	$ -	$ -	$ -
56	Materials	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000
57	0	$ -	$ -	$ -	$ -	$ -
58	Customer Service / Call Center	$ -	$ -	$ -	$ -	$ -
59	Meter Reading:	$ 11,238	$ 11,355	$ 11,462	$ 11,569	$ 11,677
60	Training Services:	$ -	$ -	$ -	$ -	$ -
61	Billing	$ -	$ -	$ -	$ -	$ -
62	**PS OM&C Cost subtotal**	**$ 56,680**	**$ 60,487**	**$ 60,993**	**$ 61,400**	**$ 61,810**
63						
64	**GCW Distribution System O,M&C**					
65	O&M	$ -	$ -	$ -	$ -	$ -
66	Maintenance Premiums	$ -	$ -	$ -	$ -	$ -
67	Materials	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000
68	Power Factor Penalties	$ -	$ -	$ -	$ -	$ -
69	Customer Service / Call Center	$ -	$ -	$ -	$ -	$ -
70	Meter Reading:	$ -	$ -	$ -	$ -	$ -
71	Training Services:	$ -	$ -	$ -	$ -	$ -
72	Billing	$ -	$ -	$ -	$ -	$ -
73	**GCW OM&C Cost subtotal**	**$ 25,000**	**$ 25,000**	**$ 25,000**	**$ 25,000**	**$ 25,000**
74	**Total Distribution System O,M&C**	**$ 81,680**	**$ 85,487**	**$ 85,993**	**$ 86,400**	**$ 86,810**
75						
76	**Net Profit / (Loss)**	**$ 82,247**	**$ 79,770**	**$ 75,455**	**$ 70,735**	**$ 66,168**
77						
78	**PS & GCW Administrative & General:**					
79	Rent	$ -	$ -	$ -	$ -	$ -
80	Utilities (Water & Electric)	$ -	$ -	$ -	$ -	$ -
81	Telephone	$ 1,200	$ 1,224	$ 1,248	$ 1,273	$ 1,299
82	Office Maintenance (Repairs, Exterminators, Janitor &	$ -	$ -	$ -	$ -	$ -
83	Salaries & Benefits	$ 60,000	$ 61,200	$ 62,424	$ 63,672	$ 64,946
84	Board Costs	$ -	$ -	$ -	$ -	$ -
85	Travel	$ -	$ -	$ -	$ -	$ -
86	Training	$ -	$ -	$ -	$ -	$ -
87	Office Materials & Supplies	$ 6,200	$ 6,324	$ 6,450	$ 6,579	$ 6,711
88	Auto (Insurance, Fuel & Mainteance)	$ -	$ -	$ -	$ -	$ -
89	Industry Experts	$ 30,000	$ 30,600	$ 31,212	$ 31,836	$ 32,473
90	Accounting	$ 5,000	$ 5,100	$ 5,202	$ 5,306	$ 5,412
91	Legal	$ 5,000	$ 5,100	$ 5,202	$ 5,306	$ 5,412
92	Misc(Payroll Service, Advertising, Bank Charges, dona	$ -	$ -	$ -	$ -	$ -
93	**PS & GCW A&G Cost subtotal**	**$ 107,400**	**$ 109,548**	**$ 111,739**	**$ 113,974**	**$ 116,253**
94						
95	**Net Profit / (Loss)**	**$ (25,153)**	**$ (29,778)**	**$ (36,284)**	**$ (43,239)**	**$ (50,085)**
96						
97						
98	**PS Debt Service**					
99	**PS Debt Service Total (P&I)**	**$ 211,262**	**$ 228,756**	**$ 246,250**	**$ 263,743**	**$ 281,237**
100						
101	**Net Profit / (Loss)**	**$ (236,415)**	**$ (258,534)**	**$ (282,534)**	**$ (306,982)**	**$ (331,322)**
102						
103	**PS & GCW Reserves/Contingencies**					
104	**Reserves/Contingencies subtotal**	**$ 5,000**	**$ 5,100**	**$ 5,202**	**$ 5,306**	**$ 5,412**
105						
106	**Net Profit / (Loss)**	**$ (241,415)**	**$ (263,634)**	**$ (287,736)**	**$ (312,288)**	**$ (336,734)**

	A	B	C	D	E	F
109	**Table 5 - PS & GCW Case A Proforma Summary**					
110		**Annual Summary**				
111		**2007**	**2008**	**2009**	**2010**	**2011**
112	Total PS Purchase Power Costs	$ 866,071	$ 901,676	$ 923,790	$ 946,485	$ 970,454
113	Plus Revenue Adjustment From Prior Year- $	$ -	$ 241,415	$ 263,634	$ 287,736	$ 312,288
114	Net Projected Revenue - $	$ 866,071	$ 1,143,091	$ 1,187,424	$ 1,234,221	$ 1,282,742
115	Needed Revenue - $	$ 1,107,486	$ 1,165,310	$ 1,211,526	$ 1,258,773	$ 1,307,188
116	Plus Current Year Adjustment - $	$ 241,415	$ 22,219	$ 24,102	$ 24,552	$ 24,446
117	Adjusted Revenue - $	$ 1,107,486	$ 1,165,310	$ 1,211,526	$ 1,258,773	$ 1,307,188
118	% Yearly Increase	27.87%	1.94%	2.03%	1.99%	1.91%

10. System Valuation

A system valuation study was undertaken as part of this project to determine an estimate for the value of the system as well as the overall condition of the facilities. A system valuation study is a field assessment of the electrical lines, substations, and related lower-level voltage equipment used to provide electrical power to the customer. All facilities are visually examined and inventoried. Analysis is made to determine the value of the facilities as well as condition. A system valuation study of the Peach Springs area was conducted and is found in Appendix A.

11. Regulatory & Government Issues

The Tribe recognizes there are regulatory and governmental issues that would need to be addressed upon the formation of a TUA. The Tribe needs to consider such issues as it determines whether to proceed with the formation of the TUA. The report provides a brief discussion of those issues that have been identified to date. Further, other issues may occur from time to time and the TUA would address them as they arise.

11.a Ordinance

A draft ordinance has been prepared and is found in Appendix B. The draft ordinance outlines how the TUA would be formed, its relationship to the Tribe and its ongoing responsibilities. Note that the TUA could be established to initially provide service to the GCW area and then expand to serve the Peach Springs area in the future.

11.b Licenses

The TUA would obtain all necessary licenses as required by the Tribe and any other third party.

11.c Permits

When operations begin, and depending upon the level of those operations the TUA may be required to obtain and comply with various tribal, state and federal environmental and occupational safety regulations. As stated earlier, the TUA would make sure that each of the necessary permits are obtained and would comply with all regulations.

12. Mitigation of Risks

This report points out that there are certain risks associated with the start up of any business including a retail electric utility company. Every effort has been made while developing this report to consider potential risks. However, the report cannot accurately predict the future. Therefore, the report suggests that the TUA would need to be prepared to undertake other measures, as situations occur to ensure the financial viability of the business. Keeping the customer's lights on would be the first priority. Some of the risks that could adversely impact the success of the TUA's efforts and possible mitigation options include but are not limited to:

- **Risk** - Forecast of operating expenses and projections of customer load growth could prove to be wrong.

➢ **Mitigation** – Maintain flexibility to adjust to forecast variations by contracting for construction, maintenance and operations services. Conduct on-going assessment of load growth to quickly determine what is working and to quickly discard what is not working. Operate conservatively and build cash reserves if possible during the first two years of operation.

- **Risk** - More rapid growth and expansion could strain the financial, operating and management systems.
  - ➢ **Mitigation** – Similar to the previous risk but requiring increasing rather than decreasing staff. Again maintain flexibility to adjust to forecast variations by contracting for construction, maintenance and operations services. Conduct on-going assessment of customer growth to quickly determine what is working and to quickly discard what is not working.
- **Risk** – The TUA's retail electric service cost could be higher than comparable MEC costs.
  - ➢ **Mitigation** – Based on the proforma this may be the case, if MEC were to not implement any rate changes during the term of the analysis. The TUA would need to operate a highly efficient and lean organization in order to ensure that it remains competitive. Energy costs are increasing for all suppliers, and this would help the TUA be competitive.

While the above are certainly risks, the report reflects the development of a conservative plan and an operating process that offers flexibility and agility to respond to changes in market conditions, thus mitigating the potential impact of the risks.

13. Havasupai Relationship

Not only would there be a relationship between the TUA and the Tribe and MEC, but that the relationship would also extend to the Havasupai Tribe. There is common bond between the Hualapai Tribe and the Havasupai Tribe as sister communities. Further, both Tribes have a connection to MEC through the MEC power line that runs from the Nelson Substation to Supai Village approximately 70 miles away. Supai Village is located in the bottom of the Grand Canyon. Supai Village has always been difficult to serve and MEC has made it very clear that it does not want the responsibility for providing service to Supai Village. At this time, the Bureau of Indian Affairs is acting in the role of electric service provider to Supai

Village, with responsibilities for delivering power to residential and commercial customers, billing and collections, disconnects and new services, and operations and maintenance of the local distribution system. MEC has been providing electricity to the BIA as a wholesale customer and has no individual retail customers on the Havasupai Reservation. However, there are Hualapai customers connected to the Supai power line along its 70-mile length that would be served by the TUA should it acquire the Supai line as a part of the development of the TUA.

This situation appears to be contentious, as the BIA and MEC have been engaged in a dispute over responsibility for the line for several years. It is anticipated that the TUA formation would initially serve only the Peach Springs area and that the acquisition of the MEC line to the Havasupai Reservation would be addressed in the future. Since MEC has made its position clear, that it does not want ownership of the line, any acquisition of the line would need to address the providing of electric service to the Havasupai Reservation. The TUA would need to proceed cautiously in this regard and carefully weigh the benefits versus the costs/risks associated with providing service to the Havasupai Reservation. A problem of this complexity demands a multi-agency approach involving federal agencies and state governments in order to achieve a solution that would carry forward into the future in a manner that is mutually beneficial to all parties. It would be the intent of the TUA to address this issue after it has established its operation in the GCW and Peach Springs areas.

14. Conclusion

The results of the analysis indicate that a TUA to provide service to the GCW area is economically viable. Expanding the TUA to include providing service to the Peach Springs area based upon current assumptions would require an increase in revenues. The level of the revenue adjustment would depend upon whether or not the wind generator was installed without grant funding. Further, the report presents a proposed Ordinance for implementing the formation of the TUA. If the Council agrees that the report, including the proforma and its business arrangements plus the proposed ordinance, provides sufficient justification that a TUA would be able to provide retail electric services at competitive prices, then the Council would affirm the report's recommendation to adopt the Ordinance forming a TUA. The Council may choose to implement a phased approach to providing retail service, by first having the TUA be responsible for the GCW area and then expand to provide service in the Peach Springs area. Assuming the Council affirms the request for the formation of a TUA, for the first time Reservation customers would have a tribally owned and operated electric utility providing service. Further, the Council's approval would continue the movement towards self-determination.

For all the above reasons, the report respectfully recommends that the Council proceed to the next stage of adopting the ordinance that would form the TUA to provide retail electric service on the Reservation, first to GCW and later, based upon economic evaluation, to the Peach Springs area.

The report and detailed proforma statements indicate that with the assumptions made the TUA would be able to provide safe and reliable service at a reasonable and competitive cost to customers in the GCW area of the Reservation without a rate adjustment. As for expanding the TUA's responsibility into the Peach Springs area, the next step would be to enter into negotiations to obtain firm prices for the key items listed below. The GCW and Peach Springs proforma would be updated to reflect the firm prices and then the Council could make its final decision as to whether to proceed with the acquisition of MEC's electric facilities on the Reservation and expand the TUA's responsibility into the Peach Springs area.

- Purchase price of MEC's electric facilities on the Reservation;
- Wheeling rates to transport power over MEC's subtransmission system to the Reservation;
- OM&C Agreement with a third party or parties; and
- Refresh the cost of purchasing of supplemental power.

Appendices

Appendix A – System Valuation

Appendix B – Ordinance

Appendix C – Explanatory Notes and Commentary on the Ordinance

Appendix D - Proforma Data

- Common Data Peach Springs
- Base Case Grand Canyon West and Peach Springs
- Case A Grand Canyon West and Peach Springs (With Wind Turbine)
- Base Case Grand Canyon West

Appendix E – Proforma Flow Chart

Appendix F – Map of Service Area

ASSESSMENT OF HUALAPAI RESERVATION DISTRIBUTION SYSTEM

SECTION 1

One of the major cost components in exploring the formation of an electric utility is the construction and/or purchase of the distribution system. The distribution system consists of medium voltage electrical lines, substations, and related lower-level voltage equipment. GRPS performed a high level valuation of the distribution facilities within the Hualapai service reservation. All of these facilities belong to Mohave Electric Cooperative.

METHODOLOGY

In performing a valuation there are several valuation methodologies that may be applicable for the sale or purchase of facilities. Valuation methodologies can relate value to physical corporate assets, the potential revenue produced by such assets (income approach), or the market value of those assets. No single method of determining the value of a business can be applied with complete reliability. The valuation of distribution assets is not an exact science, and, even when supplied with an identical set of relevant facts, experts can differ widely in their appraisal of value. Such differences generally result from applying different weights to the various factors involved, based on personal judgment and experience.

Since no single method may be relied on to produce a value that will be universally accepted, multiple methodologies, taken alone or in combination, are normally employed for setting parameters with which to estimate an asset value. However, it should be recognized that the parties in a negotiation could be expected to embrace that method which produces a result most advantageous to their respective position.

Acquisition of property by a public entity can be obtained through negotiated offer, or, failing that, by condemnation. The writer is unclear whether the Hualapai have the right of condemnation or whether State laws may apply. Consequently, the Tribe should seek legal counsel in this area.

In performing the valuation, GRPS did not consider any potential intangible value or consequential damages that may arise from an acquisition. If condemnation was required rather than a negotiated settlement, the courts would likely grant the seller market value. However, "market value" presumes a willing seller dealing with multiple willing buyers, all of whom have complete information. The following methodologies are those most likely to be applied by a court in determining the market value to be paid to a privately-owned utility by a public entity in a condemnation proceeding. However, these methodologies also serve as a valid reference point for a potential price in a negotiated acquisition. One or more of the following valuation methodologies could be utilized.

Original Cost

Original cost (OC) is derived from the values indicated on a company's accounting records and presented on its balance sheet. The OC value of a utility's assets consists of the determination of asset values based on data contained in official accounting records. Such value, for regulatory purposes, is the cost of the asset (plant) when first devoted to public service (original cost). This means that the value of its physical plant, according to its accounting records, is based on the actual costs incurred to initially install electric facilities years earlier. Original cost less depreciation (OCLLD) is OC less an applicable deduction for depreciation.

OCLD is a method that adjusts solely by age and ignores existing maintenance. When used alone, the approach does not consider the condition of the existing plant, accounts receivable, or other factors that might increase or reduce the market value. It is appropriate that some factor be applied to reflect the actual condition of the facilities being acquired. This factor is referred to as "percent condition" and is analogous to the factor a used automobile buyer may apply to the purchase price to reflect the condition and maintenance performed on the automobile.

To determine OC the following method was used:

- Replacement cost new was determined using cost estimating software on the inventory of plant.
- OC was determined using the Handy Whitman utility cost index to determine costs at the time of construction.

Capitalized Earnings Method

The capitalized earnings method for determining value involves estimating the current value of future earnings. This method is often used for placing a value on an on-going business concern. This approach is based on the premise that the value of the business is derived solely from its ability to sell its product or services at a profit in future years. Corporations often buy other corporations or divisions of those corporations for a purchase price determined on the basis of future earnings. In this case, the sale of electricity could be treated as a distinct business enterprise resulting in a value based on capitalized earnings. This method differs from the other methods in that it does not reference specific property or assets. Rather, there is an implicit assumption that in return for the purchase price, the acquiring entity will receive all of the assets necessary to achieve the projected level of future earnings. In the case of an electric distribution utility, these assets include land and land rights, and associated substation and distribution facilities. The capitalized earnings approach to valuation is dependent upon the full complement of assets being acquired. Accordingly, calculation of a capitalized earnings value does not include damages resulting from numerous factors such as loss of economies of scale. In a rate regulated environment, the capitalized earnings method would result in a value very close to the Original Cost less Depreciation (OCLD).

Replacement Cost New

- Replacement cost new (RCN), as its name implies, involves calculating the current cost of replacing the plant in question with another identical plant. Replacement cost new less depreciation (RCNLD) is RCN less an applicable deduction for depreciation. The major element that is considered in developing the RCNLD method is the cost of replacing the existing facilities.

As with OCLD, RCNLD is a method that adjusts solely by age and ignores existing maintenance and the same percent condition adjustments are required.

Percent Condition

Percent condition is an approach often used in appraisals. It is particularly applicable to most electric utility assets. The percent condition of a circuit breaker, for example, theoretically lies between 0 and 100 percent. A new circuit breaker would represent 100 percent condition. A circuit breaker that is 15 years old, but has just undergone a complete overhaul in which all existing major components were replaced with brand new components would also represent a 100 percent condition. Equipment that is in danger of eminent failure would be represented as zero percent condition. Generally, equipment that is operating properly would be rated between 40 and 100 percent condition dependent upon state of repair, the ability to repair and where the equipment lies in its maintenance cycle. For example, a pole is not repairable, but may have been treated with life extending chemicals. New parts may not be available for a breaker which is 30 years old which means the breaker would be zero percent at the time of its next scheduled maintenance, but since it is still operating properly the percent condition would be greater than zero. A typical rural utility would find its overall distribution plant in 45-75 percent condition. Accordingly, percent condition, when applied to U.S. electric utility property, results in a value less than RCN, but the value could be more or less than RCNLD. Assuming normal maintenance, RCNLD and percent condition would yield similar valuations. In the situation at hand, the required maintenance records and access are not available. All poles were visually examined and many poles showed signs of testing and some of treatment. GRPS used a small screw driver to penetrate random poles just below the ground line to test for rotting. This sampling indicated that about 7 percent of the poles should be scheduled for replacement soon and were in 5 percent condition. This would also apply to associated wood cross arms. The balance of the distribution system averages about 20 percent condition. This means that replacement of at least 90 percent of the poles and cross arms would be expected during the next 9 years.

APPROACH

In performing the valuation, GRPS looked at the value of the distribution system on the reservation, excluding the substation. MEC has numerous assets throughout the Hualapai reservation. This valuation includes only the distribution assets necessary to deliver power to the Hualapai consumers.

GRPS utilized depreciation data from Nevada Power Company as a proxy for MEC. MEC did not respond to requests for this information. GRPS conducted a field survey of the distribution system. This survey included: (a) observation of all assets throughout the service area such as major distribution facilities; (b) obtaining a complete inventory of overhead and underground distribution of facilities; and (c) random pole testing techniques.

The major purposes of the field survey and testing were to determine the condition of the facilities and to perform reasonable checks to determine major equipment inventories. Based on a preliminary assessment made in the field observations, GRPS was able to develop a model of the *potential* facilities that would be included in an acquisition. It is important to note that these numbers are preliminary. They represent a range of expected values the Hualapai might pay for all the existing facilities, but ignore the issues of severance costs.

Severance is the cost of separating one integrated distribution system into two independent systems. For example, if the Tribe purchased the main feeder from Nelson substation to Peach Springs, then MEC would have to build a new replacement line to provide service to its remaining customers in Truxton and beyond. The Tribe could, of course, opt not to acquire the MEC line and construct its own new line. These issues of severance are beyond the scope of the existing study and are not quantified in this study.

The physical appearance of the overall facilities can be characterized as average for a system of its age. The service life of equipment in the area ranges from 15 to 50 years. The average age of poles, cross arms and conductors, excluding street light poles) is 50.4 years. The average age of the street light system is 8 years. The overhead distribution system and rights-of-way show signs of deferred maintenance. While this is not uncommon for a public utility, GRPS, based upon its professional experience, rates the system as having somewhat higher than normal deferred maintenance. There are very few poles of recent vintage that are not associated with line extensions.

AREA	DATE	AGE	QTY	AVG WT. AGE	Excl St Lights
Backbone	1947	59	204	12036	
Nelson/PS	1953	53	97	5141	
Peach Springs	1958	48	26	1248	
Aviation Tap	1968	38	72	2736	
Wells	1979	27	5	135	
Misc	1994	12	7	84	
School	1999	7	15	105	
AVG AGE					**50.4**
STREET Lights	1998	8	176	1408	

VALUATION ANALYSIS

For the valuation, most negotiated sales result in purchases for values between OCLD and RCNLD with the most common range being 1.4 to 1.6 times OCLD. GRPS used construction cost analysis to determine RCN. In Part two, GRPS developed an OC construction cost trend analysis using the Handy-Whitman Construction Cost index. The valuation does not include general plant items such as buildings, trucks, computers and software since none were found on tribal land. In order to start a utility, the tribe would have to acquire/construct similar facilities.

Construction Build-Up Analysis

The RCN analysis begins with an inventory of assets. The construction units were broken down into line items suitable for Cost Works. Cost Works is a software program used to estimate construction costs for both utility and development projects. Union labor rates were used. Cost Works tracks union contract rates for major locations throughout the United States. The zip code prefix 864xx was selected as the most applicable for labor and material rates. Historical quotations for poles, conductors, and line transformers were utilized as well for the area. Labor amounts were increased to account for engineering, supervision, and overheads necessary to complete construction. The resulting RCN cost might be slightly high due to constraints of the software. For example, the software has a cost, including equipment, to purchase and install a 50 kVA overhead transformer, but not a cost to install a three phase bank of 50 kVA transformers. GRPS entered a three phase bank as 3 single phase transformer installations.

Handy-Whitman Trending Cost Analysis

The major element considered in development of the OC method is the cost of reconstructing the facilities. There is no universally accepted method for developing RCN valuation. One typical method for calculating the present day reconstruction cost of utility property is to use the cost trend index method. Trending the cost of controlling items of property eliminates the need to determine costs for large numbers of articles that individually represent only a very small portion of the assets. GRPS generally used the Handy Whitman Index of Public Utility costs for the Pacific Region. This publication has been widely used to trend earlier valuations of original cost records to estimate present day reconstruction cost and visa versa. To the extent that equipment used on the system is no longer manufactured new, the index reflects reproduction cost of these items of property (e.g., oil breakers to vacuum breakers, certain porcelain insulators with polymer insulators). Regardless of the approach to valuation used, the valuator has no choice but to substitute current technology for equipment not in current production. No cost trending of land or other general plant items such as vehicles was made.

De-escalation to OC from RCN cost is accomplished by the following: (a) the average age for each account is rounded to the nearest half year, which yields an "indexing date" for each account; (b) the index number for that indexing date is obtained along with the current index number (as of January 1, 2005); (c) the ratio of the indices yields the OC multiplier for each account. The RCN plant is multiplied by the OC multiplier and by a year to date adjustment factor to compute the OC valuation. The cost includes overheads necessary to complete construction. For cost trending of transformers and meters, GRPS assumed that only the first-time cost of installation is included and subsequent installations and relocations were covered under operations expense and were not capitalized.

RESULTS
The range of valuation of all the existing distribution system is $156,000 to $634,000. The table below summarizes the results.

FERC	DESCRIPTION	AVG AGE	ADJ AGE	USE-LIFE	DEPREC	RCN	RCNLD	OCLD
364	Poles	50.4	38	45	0.844	$1,436,520	$223,459	$18,926
365	OH Conductors	50.4	40	45	0.889	$1,576,661	$175,185	$16,121
366	UG Conduits	10	10	50	0.200	$ 13,782	$ 11,025	$ 7,917
367	UG Cable	10	10	35	0.286	$ 23,570	$ 16,836	$ 12,468
368	Transformers	50.4	34	42	0.810	$ 451,753	$ 86,048	$ 33,329
369	Services	20	20	30	0.667	$ 197,600	$ 65,867	$ 37,929
370	Meters	50.4	20	30	0.667	$ 61,664	$ 20,555	$ 2,014
373	Lights	8	8	20	0.400	$ 58,566	$ 35,139	$ 27,363
	TOTALS					$3,820,115	$ 634,113	$ 156,066

It should be pointed out that under strict accounting rules, the OCLD value would be $87,690. The percent condition approach increased the OCLD value by approximately $69,000 and RCNLD value by almost $500,000. If the tribe decided not to purchase facilities that required severance the acquisition value would be substantially reduced, however new construction costs would be incurred.

Given the substantial investment in the system required during the next 10 years, GRPS believes the **fair market value** of the system to be between **$156,000 and $210,000**. Barriers to acquisition may exist from RUS funding. The Federal Register contains the rules under which a Cooperative can sell or lease assets. A copy is provided below.

Sec. 1717.616 Sale, lease, or transfer of capital assets.

A distribution borrower may without the prior approval of RUS sell, lease, or transfer any capital asset if the following conditions are met:

(a) The borrower is not in default;

(b) In the most recent year for which data are available, the borrower achieved a TIER of at least 1.25, DSC of at least 1.25, OTIER of at least 1.1, and ODSC of at least 1.1 in each case based on the average or the best 2 out of the 3 most recent years;

(c) The sale, lease, or transfer of assets will not reduce the borrower's existing or future requirements for energy or capacity being furnished to the borrower under any wholesale power contract which has been pledged as security to the government;

(d) Fair market value is obtained for the assets;

(e) The aggregate value of assets sold, leased, or transferred in any 12-month period is less than 10 percent of the borrower's net utility plant prior to the transaction;

(f) The proceeds of such sale, lease, or transfer, less ordinary and reasonable expenses incident to such transaction, are immediately:

(1) Applied as a prepayment of all notes secured under the mortgage equally and ratably;

(2) In the case of dispositions of equipment, materials or scrap, applied to the purchase of other property useful in the borrower's utility business; or

(3) Applied to the acquisition of construction of utility plant.

AN ORDINANCE TO ESTABLISH A

HUALAPAI NATION ELECTRIC UTILITY

REVISED DRAFT – 6-22-07

NOTE: This draft ordinance was prepared by Dean B. Suagee, Hobbs, Straus, Dean & Walker, LLP, drawing on Navajo Nation Code, Title 21, Chapter 1, which established the Navajo Tribal Utility Authority, and on the Plan of Operations for the tribal electric utilities of the Gila River Indian Community and the Ak-Chin Indian Community. An accompanying memorandum provides explanatory notes and commentary.

PART 1. GENERAL PROVISIONS

Section 101. Purpose.

The purpose of this Ordinance is to authorize the establishment of a Hualapai Nation Electric Utility (HNEU) to provide electric power service within the Hualapai Reservation and on other Tribal lands under the jurisdiction of the Hualapai Tribe.

Section 102. Findings.

The Hualapai Tribal Council hereby makes the following findings:

(a) The availability of electric utility service is a necessity for economic development within the Hualapai Indian Reservation.

(b) To the extent that electric utility service is not available within the Reservation, or is available but the conditions of such service are less than adequate in terms of reliability and/or reasonableness of the costs of service, then the political integrity and economic security of the Hualapai Nation are threatened, as well as the health, welfare and safety of tribal citizens and other persons residing, doing business, or visiting within the territory of the Hualapai Nation.

(c) As the governing body of a sovereign Indian nation, the Tribal Council has the authority, pursuant to Article V of the Constitution of Hualapai Indian Tribe, to enact legislation establishing a tribal electric utility to provide service within the Hualapai Reservation.

(d) In addition to providing valuable services, the electric power industry has also been a contributing cause of some kinds of environmental degradation, including global warming and climate change largely driven by combustion of fossil fuels resulting in increases in the concentration of carbon dioxide in the atmosphere.

(e) Many of the adverse environmental impacts of fossil fuel technologies and other conventional technologies for generating electricity can be avoided or otherwise limited through policies that emphasize energy efficiency, appropriately-scaled systems for generating electricity from solar and other renewable energy resources, and by limiting the demand for electricity by promoting direct applications of solar energy for heating, lighting and cooling.

(f) Governments at all levels are beginning to respond to the problem of global warming by adopting a variety of policies to reduce emissions of carbon dioxide and encourage the use of renewable energy technologies, and energy investment decisions should be informed by awareness of such policies, including those adopted at the federal and state level.

(g) The Hualapai Nation can take a leadership role in helping America make the transition to a sustainable and environmentally friendly energy economy based on solar energy and other renewable resources, and the Hualapai Nation Electric Utility can be a leading institution of tribal government in accomplishing this objective.

Section 103. Establishment.

The Tribal Council hereby establishes the Hualapai Nation Electric Utility (HNEU). The HNEU shall be operated and governed in accordance with the provisions of this Ordinance, including any subsequent amendments to this Ordinance.

Section 104. Name, Location, and Place of Business

(a) The name of the entity established by this Ordinance is the Hualapai Nation Electric Utility, which is referred to herein as "HNEU" or the "Utility."

(b) The principal place of business and the office of HNEU shall be at Peach Springs, Arizona. The Board of Directors, in its judgment, may authorize additional offices at other locations.

Section 105. Seal

The Board of Directors shall adopt a seal in such a form and with such symbols, designs, size and colors as shall be determined by the Board. The seal shall bear the full name, "HUALAPAI NATION ELECTRIC UTILITY" and the word "ARIZONA" and the year "2007."

Section 106. Duration

The duration of the Utility is perpetual.

Section 107. Mission

(a) Two-Part Mission. The mission of the HNEU is: (1) to establish and maintain electric power service for Grand Canyon West (GCW), a Hualapai Tribal enterprise; and (2) to become the primary electric utility serving Peach Springs and other areas within the Reservation and other Hualapai Tribal lands, including areas where electric utility service is currently available and locations where such service is not currently available.

(b) Authorized Activities. In the accomplishment of its mission, the HNEU is authorized to carry out the following kinds of activities:

(1) To plan for, provide and furnish utility services to all areas of the Hualapai Indian Reservation (the "Reservation"), including lands held in trust for the Tribe outside of the boundary of the main part of the Reservation, as well as areas that are contiguous to Reservation, where such services are determined to be feasible. Such utility services shall include electric power and may include other energy-related services, including energy conservation and the use of renewable energy technologies.

(2) To promote the use of electric utility services where available in order to improve the health and welfare of the residents of the Reservation and to facilitate economic development.

(3) To acquire, construct, operate, maintain, promote and expand electric utility services on and contiguous to the Reservation.

(4) To provide a fair return to the Tribe on its investment consistent with the furnishing of utility services at reasonable cost to the residents of, businesses, and government entities on, and contiguous to, the Reservation.

(5) To do everything necessary, proper advisable, or convenient for the accomplishment of the mission set forth in this section, and to do all things incidental to or connected with such mission, which are not forbidden by law, this Ordinance, or the Constitution of the Hualapai Tribe ("Constitution").

Section 108. Definitions

Customer means any individual, business, or government entity which is provided, or which seeks to have provided, services of the utility.

Customer service means the assistance or service provided to customers, other than the actual delivery of electric power or energy, including but not limited to such items as: Line extension, system upgrade, meter testing, connections or disconnection, special meter-reading, or other assistance or service as provided in the operations manual.

Electric service means the delivery of electric energy or power by the Utility to the point of delivery pursuant to a service agreement or special contract. The requirements for such delivery are set forth in the operations manual.

Operations manual means the Utility's written compilation of its procedures and practices which govern service provided by the Utility.

Power rates means the charges established in a rate schedule(s) for electric service provided to a customer.

Service means electric service and customer service provided by the Utility.

Service agreement means the written form provided by the Utility which constitutes a binding agreement between the customer and the Utility for service except for service provided under a special contract.

Service fees means the charge for providing administrative or customer service to customers, prospective customers, and other entities having business relationships with the Utility.

Special contract means a written agreement between the Utility and a customer for special conditions of service. A special contract may include, but is not limited to, such items as: Street or area lights, traffic lights, telephone booths, irrigation pumping, unmetered services, system extensions and extended payment agreements.

Utility or HNEU means the Hualapai Nation Electric Utility established pursuant to this ordinance.

Utility office(s) means the current or future facility or facilities of the Utility which are used for conducting general business with customers.

Section 109. Reports to Tribal Council

The Board of Directors (Board) shall submit a report to the Tribal Council on an annual basis. The report shall include, but not be limited to, financial conditions, proposed budget for the upcoming fiscal year, rates for various classes of customers, progress on both parts of the HNEU's mission, and other pertinent utility matters. Any actions that the Board plans to take in the upcoming year that appear to require approval by the Tribal Council shall be highlighted in the annual report, including any request for the appropriation of tribal funds for the operation of the Utility. The Board may assign the General Manager the responsibility for preparing the report, although it shall be presented to, and must be approved by, the Board before being submitted to the Tribal Council. Failure to seek Council approval in an annual report will not necessarily preclude the Utility from taking a planned action, but, if Council approval is required, a supplemental report to Council will be required.

Section 110. Amendments

This Ordinance is subject to amendment by the Tribal Council. The Board shall maintain an up-dated version of this Ordinance for public inspection, which shall incorporate all enacted amendments, along such explanatory notes as the Board deems advisable.

PART 2. ADMINISTRATION

Section 201. Control of Operations

It is intended that control and operation of the Utility shall be patterned as closely as it is feasible on the lines of a chartered municipal electric utility of similar magnitude with a Board of Directors comparable to a Board of Directors of such a utility. The General Manager shall be responsible for the day-to-day operations of the HNEU, subject to oversight by the Board of Directors. The duties and powers of the Board of Directors are set out in section 203, and the duties and powers of the General Manager shall be determined pursuant to section 206.

Section 202. Board of Directors

(a) Composition of the Board.

(1) The Board shall consist of five members, all of whom shall be appointed in accordance with subsection (b) of this section, and subject to removal pursuant to subsection (c).

(2) Three members of the Board shall be members of the Community who have sufficient education, experience, and sound judgment to learn basic utility business practices and procedures.

(3) The remaining two members of the Board may be members or non-members of the Community and shall have not less than ten years experience in business management of substantial character and at least one of such members shall have had substantial experience in the management and operation of an electric utility.

(4) No employee of the Bureau of Indian Affairs, employee of the Utility or member of the Council shall be a member of the Board.

(b) Appointments and Terms of Office.

(1) All appointments shall be made by the Tribal Chairperson, subject to confirmation by the Tribal Council.

(2) For the initial Board, three members shall be appointed for a term of three years and two for a term of two years, or until their qualified successors have been appointed. Thereafter, all terms shall be for three years. Board members shall be eligible for reappointment.

(3) The Board shall inform the Council, in writing, at least 90 days, but not more than 120 days, of the expiration of a Board member's term and may make recommendations regarding reappointment or possible replacement candidates.

(c) Removal, Resignations, and Vacancies.

(1) Any member of the Board may be removed by the Tribal Council after a majority of the Board has recommended such removal in the Board's judgment as in the best interest of the Utility. The Council may, on its own initiative, ask the Board to make a recommendation to the Council regarding the possible removal of a Board member.

(2) Any member of the Board may resign at any time by giving written notice to the Chairperson of the Board and to the Tribal Council. Resignations shall become effective at the time specified in said notice and unless otherwise specified therein, the acceptance of such resignation shall not be necessary to make it effective.

(3) Any vacancy on the Board because of death, resignation, removal or any other cause may be filled for the unexpired portion of the term by the Tribal Chairperson, subject to confirmation by the Tribal Council.

Section 203. Board Powers and Duties

(a) In General. The direction of purpose and exercise of powers by the Board shall be subject to applicable Federal and Tribal laws and regulations. The Board shall direct the purposes and exercise the following powers and duties:

(1) The Board is delegated full authority and responsibility for the management and operation of the Utility.

(2) The Board is authorized to direct the operations to accomplish the mission set forth in section 107 of this Ordinance and to exercise the powers set forth in subsection (b) below without prior authorization or subsequent approval and all parties dealing with the Utility shall have the right to rely upon any action taken by the Board pursuant to such authorization.

(3) The Board shall exercise full power and shall be responsible for the custody and management, operation, inventory and maintenance of all utilities and facilities: and for the taking of any and all usual necessary and convenient actions incidental thereto including, should it be deemed advisable or desirable, the borrowing of funds, and the making of contracts or commitments necessary to the functioning of the Utility.

(4) The Board shall function in much the same capacity as an elected Board of Directors of a chartered municipal electric utility, and shall be responsible for making investment decisions, subject to the limitations contained herein or in any advance of funds; for the establishment and maintenance of effective operating policies; the selection of management personal; and for continuous supervision of performance.

(5) The Board shall exercise its authorized powers in the best interest of the Hualapai Nation within the limits of responsible business judgment and with the stipulation that it shall not incur contract obligations in excess of the ability of the Utility to make payments on due dates.

(6) Members of the Board shall be reimbursed for expenses incurred in attending its meetings, and the Board, in its discretion, may propose a fee to be paid to its members (subject to the approval of the Tribal Council) on a per-meeting or on an annual basis.

(7) As provided in section 109, the Board shall make a formal report to the Council annually. Quarterly reports will be provided to the Council for informational purposes.

(8) The Board shall establish policies and procedures, giving usual and essential latitude to the General Manager and his delegated employees, but establishing limitations on amounts which may be expended without specific approval of the Board.

(9) No contract or other transaction between the Utility and any one of the members of the Board, or between the Utility and any corporation, partnership, firm or other legal entity in which one or more of the members of the Board has an interest directly or indirectly shall be valid, for the purpose, unless the entire interest of the Board member or members of such corporation, firm or legal entity is fully disclosed to the Board and the proposed contract or transaction shall be approved, ratified or affirmed by the vote of at least a majority of the entire Board who are not so interested.

(b) Enumerated Powers. Subject to Tribal Council approval where required and applicable Tribal and Federal laws and regulations, and solely in furtherance of the mission set forth in Section 107 of this Ordinance, the Board shall have the following powers:

(1) Facilities. The Board shall exercise full authority and shall be responsible for the custody, management, maintenance and operation of all electric utility property and facilities owned and operated by the Tribe, including such expansions and enlargements thereof as shall be authorized for the

acquisition planning, construction, maintenance and operation of additional electric utility facilities including the negotiation and execution of engineering and construction contracts and for taking of any and all usual, necessary and convenient actions incident thereto.

(2) Capacity to Act. The Board shall have the authority to act, and to direct its Officers to act, in the same capacity as that of natural person, but to have authority to perform only such acts as necessary, convenient, or expedient to accomplish the mission set forth in section 107 of this Ordinance, and such as are not contrary to laws and regulations applicable to this Utility.

(3) To Appoint Officers and Agents. The Board shall have the authority to elect or appoint officers, agents, engineers, auditors, attorneys and such other professional consultants as in the opinion of the Board may be needed from time to time, and to define their duties and fix their compensation. The Board, at Utility expense, shall require the bonding of all officers, agents or employees responsible for the handling of safeguarding of funds, property or other assets of the Utility.

(4) To Act as Agency. The Board shall have the authority to act in any state, territory, district, or possession of the United States, or in any foreign country for and on behalf of the Utility.

(5) To Deal in Real Property. The Board shall have the authority to negotiate the acquisition of (by purchase, exchange, lease, hire or otherwise), real estate of every kind, character and description and any interest therein, necessary or incidental to the mission set forth in section 107 of this Ordinance except as prohibited by law or as limited by the Constitution of the Hualapai Indian Tribe. Title to all such real property shall be taken in the name of the Tribe and title to all trust or restricted real property shall be and remain in its trust or restricted status.

(6) To Deal in Personal Property. The Board shall have the authority to acquire (by purchase, exchange, lease, hire or otherwise), hold, own, manage, operate, mortgage, pledge, hypothecate, exchange, sell, deal in and dispose of, either alone or in conjunction with others, personal property and interest therein and commodities of every kind, character and description necessary or incidental to the mission set forth in section 107 of this Ordinance.

(7) To Deal in Inventions, Copyrights, and Trademarks. The Board shall have the authority to acquire by application, assignment, purchase, exchange, lease, hire or otherwise to hold, own, use license, lease, and sell, either alone or in conjunction with others, the absolute or any partial or qualified interest in and to inventions, improvements, letters patent and applications for patents, licenses, formulas, privileges, process, copyrights and applications for copyrights,

trademarks and applications for trademarks, and trade names, and that title of all such acquisitions shall be taken in the name of the Utility for the Tribe.

(8) To Execute Guaranties. The Board shall have the authority to make any guaranty respecting indebtedness, interest, contracts, or other obligations lawfully entered into by or on behalf of the Utility, to the extent that such guaranty is made in pursuance of the mission set forth in section 107 of this ordinance, provided, that no such guaranty in excess of Two Hundred Fifty Thousand and no/100 Dollars ($250,000.00) shall be made without the prior written approval of the Tribal Council, provided that any such guarantee must conform to any applicable requirements of the Constitution of the Hualapai Indian Tribe.

(9) Depositories. The Board shall have the authority to designate and approve all depositories used for the deposit of funds of the Utility.

(10) The Board shall have the authority to enter into, make, perform and carry out or cancel and rescind, contracts for any lawful purposes pertaining to its business necessary or incidental to the mission set forth in section 107 of this Ordinance, including the negotiation of contracts that are subject to 25 U.S.C. § 81 as may be amended, which shall, as therein provided, become effective only upon the approval of the Secretary of the Interior.

(11) To Approve Budgets. The Board shall have the authority to grant initial approval to annual Utility budgets, and to make final approval action with reference to the use of funds under the exclusive control of the Utility for operating and capital addition purpose. With respect to funds in the Utility's budget that are appropriated by the Tribal Council from Tribal funds for use by the Utility, or that are obtained under the authority of the Tribe through grant or contract, the expenditure of such funds by the Board must be in accordance with a budget that has been approved by the Tribal Council.

(12) To Issue Bonds. The Board is authorized to issue bonds to finance investments made by the Utility, provided that such bonds meet the requirements for bonds issued by tribal governments pursuant to the Indian Tribal Government Tax Status Act, 24 U.S.C. § 7871. Any such bond issue must have the prior approval of the Tribal Council and may be subject to a referendum pursuant to the Constitution of the Hualapai Tribe. Total long-term indebtedness pursuant to bonds issued by the Utility shall not exceed ______________.

(13) Hearings. The Board is authorized to hold public hearings to receive in put from members of the Tribe and the general public on any topic on which the Board determines that such input would be useful.

(c) Ancillary Powers. The Board shall have and exercise all powers necessary or convenient to implement and effect any or all of the purposes for which the Utility is organized.

(d) Powers Not To Be Construed as Purposes. The powers enumerated herein shall not be construed as purposes of the Utility, but the Utility shall have and exercise such powers solely in furtherance of, but not in addition to, the mission set forth in Section 107 of this Ordinance.

Section 204. Meetings of the Board

(a) Quarterly Meetings. The Board shall meet at least quarterly upon notice establishing the time and place.

(b) Annual Meeting. The annual meeting of the Board shall be held at 10:00 a.m., on the second Monday of January of each year at the principal place of business, or at such other place as the Board shall establish. If the annual meeting is held at the time, date, and place set forth in this subsection, then no notice shall be required for the annual meeting.

(c) Special Meetings. Special meetings of the Board may be held upon notice given by the Chairperson, or Secretary, or by any three members of the Board, at such place as the Board shall direct or as shall be established by the notice.

(d) Notice. Notice of meetings stating the time, date and location shall be given in writing properly addressed to each member according to the latest available Utility records, not less than five days immediately preceding the meeting, excluding the day of the meeting. If the notice is issued more than thirty days prior to the meeting date, a supplemental notice will be provided less than thirty days prior to the meeting date.

(e) Waiver of Notice. The notice may be waived in writing signed by the Board member or members entitled to such notice whether before or after the time stated therein and such waiver shall be deemed equivalent to the giving of such notice. Attendance of any member at such quarterly or special meeting shall constitute of waiver of notice.

(f) Quorum. Three members of the Board shall constitute a quorum for the transaction of any business. The act of the majority of the members present and voting at a meeting at which a quorum is present shall be the act of the Board.

Section 205. Officers of the Board

(a) The officers of the Board shall consist of a Chairperson, Vice Chairperson, Secretary, and Treasurer. At the discretion of the Board, there may be an Assistant

Secretary and Assistant Treasurer. The Assistant Secretary and Assistant Treasurer positions may be held by the same Board member.

(b) The officers of the Board shall have the following duties and such other duties as may be determined by resolution of the Board, not inconsistent with this Ordinance.

(1) The Chairperson shall, if present, preside at all meetings of the Board and shall perform all the duties incident to the office of the Chairperson of the board and such other duties as may be delegated to the Chairperson by the Board.

(2) The Vice Chairperson shall act in the capacity of the Chairperson in the absence of the latter, and shall discharge any other duties designated by the Chairperson.

(3) The Secretary shall perform all duties incident to the office of Secretary, and such other duties as may, from time to time, be assigned by the Board or the Chairperson.

(4) The Treasurer shall perform all duties incident to the office of the Treasurer and such other duties as may, from time to time, be assigned by the Board or the Chairperson. The Treasurer shall render, or cause to be rendered, to the Chairperson and the Board whenever required, an account of all transactions as Treasurer and the financial condition of the Utility. The Treasurer shall, at the expense of the Utility, give a bond for the faithful performance and discharge of duties as Treasurer in such an amount, or so conditioned, and with such surety of sureties as the Board may require.

(c) The officers of the Board shall be chosen annually by the Board at its annual meeting.

(d) Any officer or agent elected or appointed by the Board may be removed by the Board whenever, in its judgment, the best interest of the Utility will be served thereby.

(e) Any officer may resign as an officer at any time by giving written notice to the Board, or to the Chairperson, or Secretary, such resignation to take effect at the time specified therein, and, unless otherwise specified therein, the acceptance of such resignation shall not be necessary to make it effective. Any vacancy in any office because of death, resignation, removal, or any other cause may be filled for the unexpired part of the term at the next regular meeting of the Board. Resignation form the Board and appointments to fill vacancies on the Board are governed by section 202.

Section 206. General Manager

The General Manager shall be employed by the Board under a written employment contract and shall be responsible to the Board. The delegations to the General Manager and his/her duties and responsibilities shall be specified in the applicable Board policies.

Section 207. Indemnification of Board Members and Employees

The Utility shall indemnify any officer, employee or member of the Board or former officer, employee or member of the Board, or any person who may have served at its request as an officer, employee or member of the Board, against reasonable expenses actually and necessarily incurred in connection with the defense of any action, suit or proceeding in which s/he is made a party by reason of being, or having been such officer, employee or member of the Board except in relation to matters as to which s/he shall be adjudged in such action, suit or proceeding to be liable for negligence or misconduct in the performance of duty, or except in relations to matters in which employee was acting beyond the scope of his employment. The Utility shall also reimburse to any officer, employee or member of the Board reasonable cost of settlements of any such action, suit or proceeding if it shall be found by a majority of the Board other than Board members involved in the matter of controversy (whether or not a quorum exists) that it is in the best interest of the Utility and the Hualapai Nation that such a settlement be made and that such officer, employee, or member of the Board was not guilty of negligence or misconduct. Such rights of indemnification and reimbursement shall not be deemed exclusive of any other rights which such officer, employee or member of the Board may be entitled to receive.

Section 208. Bonds and Notes for Support of the Utility

(a) No Material Change during Terms of Notes and Bonds. The Hualapai Tribal Council does hereby pledge to contract and agree with any person, firm, or corporation, or any federal, tribal, or state agency subscribing to or acquiring notes or bonds of the Utility issued for purposes of the Utility, that it obligates itself not to limit or alter the rights or powers vested in the Utility in any material way until such notes or bonds, at any time issued, together with interest thereon, are fully met, paid, and discharged. The Hualapai Tribal Council does further pledge to contract and agree with any federal agency that, in the event any such agency shall loan or contribute any funds for construction, extension, improvement or enlargement of any facilities, the Hualapai Tribal Council will not alter or limit the rights or powers of the Utility in any manner that would be inconsistent with the continued operation and maintenance of such facilities or the extension, improvement, or enlargement thereof, or which would be inconsistent with the due performance of any agreements between the Utility and any such federal agency; and the Utility shall continue to have and may exercise all rights and powers under this ordinance, so long as the same shall be necessary or desirable for carrying out its purposes and those of any federal agency loaning or contributing funds for the construction, extension, improvement, or enlargement of any facilities.

(b) Agreements with Federal Agencies. Any agreement of the Utility with a federal agency regarding the construction, extension, improvement, enlargement, or protection of any facilities may be enforced against the Utility in the appropriate federal district court of appropriate jurisdiction, or in the courts of the Hualapai Tribe according to their respective terms, including any obligations of the Utility to pay compensatory damages in the event of failure to perform.

(c) **Remedies of Note or Bond Holders.** Subject to any contractual limitations binding upon the holders of any issue of notes or bonds, or trustees for such holders, including but not limited to the restriction of the exercise of any remedy to a specified proportion or percentage of such holders, any holder of any note or bond, or trustee for such holder, shall have the right and power, for the equal benefit and protection of all holders of notes or bonds similarly situated:

(1) By mandamus or other suit, action, or proceeding at law or in equity in the Courts of the Hualapai Tribe to compel the Utility and its board, officers, agents, or employees to perform and carry out their duties and obligations under the Utility's covenants and agreements with such holders;

(2) By action or suit in equity to require the Utility and its board to account as if they were the trustees of an express trust;

(3) By action, suit, or other proceeding at law or in equity to have a receiver appointed and/or to enforce any pledge, lien, or security agreement given in connection with the issuance of any note or bond, such enforcement right to include the power to possess, control, and sell the security in accordance with the applicable security agreement, lien, or pledge;

(4) By action or suit in equity against the Utility or its board to enjoin any acts or things which may be unlawful or in violation of the rights of the note or bond holders; and

(5) To bring suit against the Utility upon the notes or bonds, security instruments, or loan contracts.

No remedy conferred by this section upon any holder of the notes or bonds, or any trustee for such a holder, is intended to be exclusive of any other remedy, but each such remedy is cumulative and in addition to every other remedy, and may be exercised without exhausting and without regard to any other remedy conferred by this section or by any other law. No waiver of any default or breach of duty of contract, whether by any holder of the notes or bonds, or any trustee for such a holder, shall extend to or shall affect any subsequent default or breach of duty of contract or shall impair any rights or remedies thereon. No delay or omission of any note or bond holder, or any trustee for such a holder, to exercise any right or power accruing upon default shall impair any such right or power or shall be construed to be a waiver of any such default or acquiescence therein. Every substantive right and every remedy, conferred upon such holder may be enforced and exercised from time to time as often as may be deemed expedient. In case any suit, action, or proceeding to enforce any right or exercise any remedy shall be determined adversely to the holder of the note or the bond, or any trustee for such a holder, then in every such case the Utility and such holder, or such trustee, shall be restored to their former positions and rights and remedies as if no such suit, action, or proceeding had been brought or taken.

(d) Limited Waiver of Sovereign Immunity. Subsections (b) and (c) of this section shall be construed as an explicitly limited exception to the sovereign immunity of the Hualapai Tribe and shall not be construed to waive any immunity of the Hualapai Tribe, nor to extend any liability to any assets, revenues, or incomes of the Hualapai Tribe, other than those of the Utility. The waiver in subsection (c) is expressly limited to actions in the Courts of the Hualapai Tribe. A waiver of sovereign immunity pursuant to this section may require a referendum in accordance with Article VI of the Constitution of the Hualapai Indian Tribe.

Section 209. Enforceability of Contracts.

(a) Contracts in the Course of Utility Operations. The Utility is authorized to enter into contracts in the course of conducting its operations, and such contracts shall be enforceable in a proceeding at law or in equity in the Courts of the Hualapai Tribe in accordance with this section. The Board shall develop a standard clause to be included in such contracts, which shall be presented to the Tribal Council for approval. Once such a clause has been approved by the Council, no further action by the council is required for such a contract to be enforceable in the Courts of the Hualapai Tribe. Until such a standard clause has been approved, or in the event that a party to a contract with the Utility does not agree to be bound by the standard clause, a clause on enforceability for any such contract will require approval by the Tribal Council.

(b) Enforceability of Service Agreements and Special Contracts. The Board shall develop a standard clause to be included in its service agreements and special contracts with customers to ensure that such contracts can be enforced in the Courts of the Hualapai Tribe. The standard clause may limit the extent which the Utility will be liable for damages resulting from power outages or other failures to provide service. This standard clause shall be presented to the Tribal Council for approval. Once such a clause has been approved by the Council, no further action by the council is required for such a contract to be enforceable in the Courts of the Hualapai Tribe.

(c) Limited Waiver of Sovereign Immunity. Subsections (a) and (b) of this section shall be construed as a limited exception to the general sovereign immunity of the Hualapai Tribe and shall not be construed to waive any immunity of the Hualapai Tribe, nor to extend any liability to any assets, revenues, or incomes of the Hualapai Tribe, other than those of the Utility. A waiver of sovereign immunity pursuant to this section may require a referendum in accordance with Article VI of the Constitution of the Hualapai Indian Tribe.

Section 210. Accounting and Fiscal Year

A modern accounting system shall be established and installed in conformity with accounting principles generally accepted in the utility business. The accounting system shall insure the availability of information as may be necessary to comply with applicable Federal, State, and Tribal regulatory requirements. Use of automatic data processing is encouraged. The fiscal year of the Utility shall be from October 1 to September 30.

Section 211. Records, Inspections, and Audits

The books, records and property of the Utility shall be available for inspection at all reasonable times by authorized representatives of the Tribal Council. The accounts and records of the Utility shall be audited at the close of each fiscal year. Copies of such Audit Reports shall be furnished to the parties receiving copies of the financial and operating statements and to the Tribal Council.

Section 212. Insurance

Insurance, including liability, adequate and sufficient to protect the interests of the United States and the Tribe from loss by fire of other disaster shall be carried by the Utility.

PART 3. OPERATIONS

Section 301. Operations Manual

The General Manager shall prepare and present to the Board for its approval an Operations Manual for the Utility. The Operations Manual shall be a written compilation of its procedures and practices which govern service provided by the utility and shall include such information as the Board directs, or the General Manager determines should be included, to supplement the information set out in this Ordinance. The Operations Manual may be altered, amended or repealed by the Tribal Council at any regular or special meeting, provided notice of such meeting shall have contained a copy of the proposed alteration, amendment or repeal and shall be at least ten (10) days prior to the meeting.

Section 302. Annual Budget

The General Manager shall prepare and present to the Board for its approval an annual budget for the Utility. The timing of the preparation and Board approval of the annual budget shall be done in a way that is coordinated with the budget process used by the Tribal Council. To the extent that the Utility's annual budget includes planned expenditures of any tribal funds or federal funds subject to control of the Tribal Council, the Utility's budget must be approved by the Tribal Council.

Section 303. Five Year Plan

The Board is responsible for the preparation of a five-year plan for the development of the Utility, which shall include both plans for both the initial phase and the expansion phase as described in section 107 of this Ordinance. The five-year plan shall be updated on a biennial basis. The five-year plan shall be available for review by tribal members and the general public, and the Board shall accept written comments on the five-year plan on an on-going basis.

Section 304. Rates and Other Charges for Services

(a) Setting Rates. The Board shall propose all rates and charges for utility services, and when adopted by the Council shall become effective at such time as the Council shall determine. Upon a petition being filed by any fifty (50) users, the Utility shall, after giving such notice as the Board may determine to be adequate, hold a formal public hearing to review such rates and charges.

(b) Allowable Considerations. The Board is authorized to adopt rate designs that encourage energy efficiency and/or the distributed generation of electricity using renewable energy technologies.

(c) Classes of Service. The Board may establish different classes of service that are subject to different rates. The rationale for any such classes of service must be specifically explained to the Tribal Council when the rate design is presented for Council approval.

(d) Appeals. The Board shall establish procedures to provide for appeals of rate decisions to the Council.

Section 305. Energy Conservation Services

The Utility is authorized to develop programs and provide services to help households, businesses, and other energy users to adopt energy efficiency and conservation measures to reduce their demands for electric power.

Section 306. Solar and Renewable Energy Services

The Utility is authorized to develop programs and provide services to help households, businesses, and other energy users to make use of technologies that use solar energy and other renewable energy resources, including but not limited to technologies that produce electric power.

Section 307. Information and Educational Services

The Utility is authorized to develop programs and provide services to help households, businesses, and other energy users become more informed about the full range of issues relating to energy.

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June 30, 2007

MEMORANDUM

To: Hualapai Tribe Electric Utility Project Advisory Committee

From: Dean B. Suagee

Subject: Explanatory Notes and Commentary on the
Draft Ordinance to Establish a Hualapai Nation Electric Utility

INTRODUCTION

The Hualapai Tribe has received financial assistance from the U.S. Department of Energy (DOE) to establish a tribal electric utility to manage the electric power system at Grand Canyon West (GCW). The GCW facility, which is powered in part with solar electricity, is not connected to the electric power grid. The work plan for the DOE-funded project includes developing a plan for the possible acquisition and operation of the power grid serving Peach Springs and other areas within the Reservation, where service is currently provided by Mohave Electric Cooperative (MEC).

One of the written work products of the DOE-funded project is a draft ordinance for consideration by the Hualapai Tribal Council. Under Article XIV of the Hualapai Constitution, actions by the Tribal Council that are "of permanent interest shall be embodied in ordinances." The creation of a tribal electric utility is such an action, and so the enactment of an ordinance is the appropriate way for the Council to act. This memorandum provides explanatory notes and commentary on the draft Ordinance to Establish a Hualapai Nation Electric Utility, dated June 20, 2007. The draft ordinance would create a tribal electric utility, referred to in the draft as the Hualapai Nation Electric Utility (HNEU), which would have the authority to manage the GCW system. The HNEU would also have authority to proceed with planning for the acquisition and operation of the power gird within Peach Springs and the rest of the Reservation. The actual expansion of utility service by HNEU to Peach Springs would require action by the Tribal Council.

The electric utility industry is comprised of more than 3,000 utilities, with several different models of organization, including investor-owned utilities, municipal government utilities, rural electric cooperatives, federal power authorities, and a small number of tribal electric utilities. The industry has traditionally been regulated, for the most part, by state public utility commissions, with some aspects regulated by federal agencies. The industry has been going through some rather major changes over the last two decades or so, and there has not been a lot of attention paid to where tribal governments fit into this evolving industry. There are a number of the issues that are raised by the creation of a tribal electric utility. Those issues are discussed in some detail in a separate paper that is attached to this memorandum as Addendum A, a paper captioned “Restructuring, Unbundling, and Global Warming: Where Do Tribal Governments Fit in the Evolving Electric Power Industry.” At various points in this memorandum, references are made to points discussed in the Addendum, and that paper should be considered part of the deliberative process as the Council considers taking action to create a tribal electric utility.

The draft Ordinance would establish the HNEU as an institution of tribal government, with a General Manager and a Board of Directors. An institution of tribal government is not the only way that an electric utility could be established. The reasons for recommending the option are discussed in the Addendum, particularly in the sections on regulatory jurisdiction and tax implications (in section II.C. of the Addendum).

It should also be noted that an alternative strategy would be to work from within the structure of the existing utility serving the Reservation with the objective of, in effect, taking it over from within. While such an approach may be realistic for some tribes, this option is not considered practical for the Hualapai Nation.

OVERVIEW OF THE DRAFT ORDINANCE

The draft Ordinance is comprised of twenty-nine sections, grouped into three parts. Part 1 is captioned “General Provisions” and includes sections on the Purpose of the Ordinance, Findings by the Tribal Council, Definitions, and a Mission statement. Part 2 is captioned “Administration” and establishes the governance structure for the Utility, in which authority is vested in a Board of Directors that reports to the Tribal Council and a General Manager responsible for day-to-day operations. Part 3 is captioned “Operations” and sets out a framework for day-to-day operations. Part 3 also includes broad authorizations for the Utility to develop the capability to provide services to assist customers with energy efficiency services and with solar and renewable energy systems.

This draft ordinance was prepared drawing on Navajo Nation Code, Title 21, Chapter 1, which established the Navajo Tribal Utility Authority, and on the Plan of Operations for the tribal electric utilities of the Gila River Indian Community and the Ak-Chin Indian Community. Some of the comments in the Section-by Section Commentary that follows include references to those source documents.

SECTION-BY-SECTION SUMMARY WITH NOTES AND COMMENTARY

PART 1. GENERAL PROVISIONS

Section 101. Purpose. This section simply states that the purpose of the Ordinance is to authorize the establishment of a Hualapai Nation Electric Utility. The reference to "other Tribal lands under the jurisdiction of the Hualapai Tribe" is intended to cover parcels of Hualapai tribal trust land outside the boundary of the Reservation, most of which are to the south and west of the southwestern boundary. The ordinance would apply to all lands under the jurisdiction of the Tribe as stated in Article I of the Tribe's Constitution.

Section 102. Findings. This section contains legislative findings, which are sets out in seven paragraphs designated (a) through (g). Comments on two of the findings are offered here.

Paragraph (b) incorporates language from the second exception to the "general proposition" that the U.S. Supreme Court announced in *Montana v. United States* (1981), in which the Court said that the inherent sovereignty of tribal governments generally does not extend to nonmembers of the tribe. While that limitation on tribal sovereignty was applied in a case in which tribal sovereignty was only at issue with respect to lands within a reservation that were not held in federal Indian trust status, in the 2001 decision in *Nevada v. Hicks*, the Supreme Court applied the general proposition to tribal trust lands. In light of that case law, paragraph (b) states a finding that the *Montana* "general proposition" does not apply. These cases are discussed in the Addendum, under heading II.C.1, "Regulatory Jurisdiction." The body of court decisions finding implicit limitations on inherent tribal sovereignty cannot be ignored. As discussed in the Addendum, the risks associated with that body of court decisions can be reduced by creating the electric utility as an institution of tribal government, rather than as a corporate entity separate from the Tribe.

Paragraph (f) takes note of actions by governments at all levels to deal with the problem of global warming, which is caused, for the most part, by burning fossil fuels. The point of this finding is that the financial analysis of an investment in electric power will be affected by governmental policies beyond the control of the Hualapai Tribal Council, and we can expect the trend to be toward more incentives for renewable energy technologies and more disincentives for fossil fuels. Some of the issues relating to global warming are discussed in the Addendum.

Section 103. Establishment. This section states that the Tribal Council "hereby establishes" the HNEU.

Section 104. Name, Location, and Place of Business. This section states simply says that the name of the electric utility is the Hualapai Nation Electric Utility, which is referred to in the Ordinance as "HNEU" or the "Utility," and that its principal place of business will be in Peach Springs.

The name used in this draft is just a suggestion. Other ideas would be to use the words “Public Service Company” or “Energy Service Company” or to include the word “Authority.” (In my personal experience, some people attach negative connotations to the word “Authority” when used in the name of an institution of government.) We might want to choose a name that makes an acronym that is easy to pronounce and remember. For example, either “Reservation Energy Service Company” or “Renewable Energy Service Company” could be abbreviated as RESCO, and pronounced “Rez–co.”

Section 105. Seal. This section authorizes the Utility’s Board to adopt a seal.

Section 106. Duration. This section says that the duration of the Utility is perpetual.

Section 107. Mission. This section sets out the mission of the Utility. Paragraph (a) says that the Utility has a two-part mission: first, to establish and maintain electric power service for Grand Canyon West; and, second, to become the primary electric utility serving Peach Springs and other areas within the Tribe’s jurisdictional territory.

Paragraph (b) sets out a list of five kinds of authorized activities. With respect to paragraph (3), it should be noted that the sample organizational documents that I drew upon also authorize the tribal utility to branch out (or investigate branching out) into other kinds of utility services, e.g., gas, water, sewer. This draft does not include such language, as it is my understanding that the new tribal utility will be limited to energy services. Such an expansive mission could be added at a later date by amending the ordinance. With respect to paragraph (4), the Navajo Nation code says that utility service is to be provided at “low cost”; this draft says at “reasonable cost.”

In addition, the Navajo Nation Code includes language saying that the utility shall give preference in employment to Tribal members. This draft does not include such language, but the issue should be considered by the Tribal Council, that is, whether the Utility should be explicitly subject to tribal employment preference.

Section 108. Definitions. The definitions in this section could be considered a starting point. The definitions that are included here, except for the definition of “Utility or HNEU,” have been taken from definitions in the Bureau of Indian Affairs (BIA) regulations for the electric utilities that the BIA operates, definitions that are codified at 25 C.F.R. § 175.1. Some of these definitions may need to be revised. We also need to make a list of other terms that need definitions.

Section 109. Reports to Tribal Council. This section requires an annual report to the Tribal Council. Section 203(a) is another section that calls for an annual report to Council. That section includes filing a report with the Council among the duties of the Board. This section specifies what the report is supposed to include. While these sections could be combined, I chose not to because setting out the required content of the report to Council in a section with that caption draws attention to the ultimate authority of the Council over the Board.

Section 110. Amendments. This section says that Ordinance is subject to amendment by the Tribal Council and directs the Board to maintain an up-dated version of the Ordinance for public inspection.

PART 2. ADMINISTRATION

Section 201. Control of Operations. This section says that the management of the Utility is under the control of a General Manager, with oversight performed by a Board of Directors. The control and operation of the utility are to be "patterned as closely as it is feasible along the lines of a chartered municipal electric utility of similar magnitude." It should be noted that the Navajo Nation code and other samples say the pattern is to be a "public service corporation." In my view, that is not the appropriate pattern because a public service corporation is a private for-profit corporation with a duty to provide a return on investment to its shareholders. I think that a municipal electric utility is a more appropriate model, since a municipal utility's mission is to provide a public service. The term "public service company" as applied to an investor-owned utility is somewhat misleading – such a utility does provide a public service, but, as reflected in the form of its corporate existence, its main purpose is to make money for its shareholders. This issue is discussed in some detail in the Addendum, section II.B. The topic of governance of a tribal utility is discussed in section II.C.3 of the Addendum.

Section 202. Board of Directors. This section sets out the composition of the Board, how appointments are made, terms of office, removal, resignations, and how vacancies are filled. In paragraph (b)(2), there is language regarding the appointment of the initial Board which is intended to avoid complete turnover of the Board. None of the initial appointments would be for one year since that is probably not long enough to really learn the role of Board member.

During the initial phase of the HNEU, that is, the GCW non-interconnected utility phase, an alternative to establishing a new Board would be to authorize an existing tribal government institution, such as the Tribal Environmental Review Commission (TERC) Board, to perform the powers and duties of the Board of Directors. Since the TERC Board is the advisory committee for the project, that might be an efficient way to carry out the start-up phase. That option could be written into the Tribal Council resolution enacting the ordinance, and it could expressly limit the period for which the TERC Board would serve in that capacity, perhaps for twelve months. This draft calls for a Board comprised of five members, in response to comments from the Project Team in reviewing an earlier draft. The TERC Board consists of seven members, so if the Council were to decide to use the TERC Board during the start-up phase, the Tribal Council resolution should say that the provisions in this section regarding composition of the Board, quorum and such will not apply during the start-up phase.

Section 203. Board Powers and Duties. This section sets out the powers and duties of the Board, under two headings: (a) general, and (b) enumerated powers.

With respect to paragraph (a)(3), it should be noted that contracts will not be enforceable without a limited waiver of tribal sovereign immunity. This issue is addressed in sections 208 and 209. The subject of sovereign immunity is discussed in section II.C.4 of the Addendum.

With respect to paragraph (a)(4), it should be noted that the Navajo Nation code makes the appointment of the General Manager subject to Council approval. This draft does not include such a provision.

With respect to paragraph (a)(7), which includes a cross-reference to section 109, that section summarizes the contents of an annual report to Council; this section specifies that making such a report is the responsibility of the Board.

With respect to paragraph (a)(8), regarding the establishment of policies and procedures, the Navajo Nation Code says “purchasing” policies and procedures. In this draft, the Board’s power is implicitly somewhat broader. Should there be any explicit limits on the kinds of policies and procedures the Board can establish?

With respect to paragraph (a)(9), the Navajo Nation Code has two additional paragraphs at this point: subsection 7.A.12 gives the board discretion to ask the Economic Development Committee of the Navajo Nation Council to review and approve any contract; subsection 7.A.13 requires the board to seek such approval if an officer or employee of the Navajo Nation “may have an interest directly or indirectly in the matter or transaction.”

With respect to paragraph (b)(3), the Navajo Nation Code requires the Board to use the same accounting firm that the Navajo Nation uses.

With respect to paragraph (b)(5) authorizes the Board to negotiate the acquisition of real property. This language is modeled on the Navajo Nation Code, with additional language referring to the Constitution of the Hualapai Indian Tribe.

With respect to paragraph (b)(6), this draft uses the word “hypothecate,” which means: “To pledge (property) as security to a creditor without transfer of title or possession; to mortgage.” American Heritage Dictionary of the English Language.

With respect to paragraph (b)(7), the Navajo Nation Code just says in the name of the Navajo Nation. This draft says in the name of the Utility for the Tribe, but perhaps it should likewise just say in the name of the Tribe.

With respect to paragraph (b)(8), the corresponding subsection of the Navajo Nation Code, which is the original source of this language, set the limit on guarantees without Tribal Council approval at $200,000. That statutory language appears to have been most recently amended in 1985, and the rationale behind the $200,000 limitation is not explained. In this draft, the limit for guarantees is set at $250,000 with a reference to Article VI, section 2 of the Tribe’s Constitution, which limits waivers of sovereign immunity to $250,000 except by referendum.

With respect to paragraph (b)(10), the reference to 25 U.S.C. § 81 appears in the corresponding section of the Navajo Nation Code. That federal statute – 25 U.S.C. § 81 – was amended in 2000. As amended, contracts and agreements that encumber tribal trust land only require approval of the Secretary of Interior if the period of encumbrance is seven years or longer. It should be noted that, as amended, this federal statute opens up new possibilities for structuring transactions – if an agreement is written such that investors get their returns in less than seven years, a tribe can pledge an interest in trust land as security, and no BIA approval is required. This section, as drafted, authorizes the Utility's Board to enter into such agreements.

With respect to paragraph (b)(11), this section draws a distinction between funds that are under the exclusive control of the Board (e.g., revenue from operations) and funds that are appropriated for the Utility's use by the Tribal Council.

With respect to paragraph (b)(12), this paragraph is intended to provide for the possibility of using bonds to finance investments made by the Utility. The Indian Tribal Government Tax Status Act authorizes tribal governments to issue bonds in much the same way that state and local governments issue bonds to finance investments in construction of the infrastructure to deliver governmental services, such as schools, roads, and government buildings. The statutory language authorizing this is codified at 24 U.S.C. § 7871. Bonds issued by tribal governments must be for "essential governmental functions" in order for the interest paid on the bonds to be tax exempt. Commercial or industrial activity does not qualify for bond financing. The Internal Revenue Service recently published an advance notice of proposed rulemaking on this issue, 71 Fed. Reg. 45474 (Aug. 9, 2006), in which IRS announced its intent to develop rules to clarify the term "essential governmental functions." Investments in a power grid and generating facilities owned by a tribal electric utility might meet the essential governmental function test, but there will be uncertainty until IRS makes a ruling, and there could be some distinctions drawn for generating equipment in which private investors have equity interests. This issue involves some uncharted territory. Aside from questions regarding generating facilities, the IRS advance notice of proposed rulemaking indicates that facilities such as governmental office buildings and school buildings would qualify for bond financing, and so, presumably, energy efficiency measures and renewable energy features incorporated into such buildings should qualify. This issue is discussed in section II.C.5 of the Addendum. It should also be noted that for many years NCAI has advocated amending the law so that tribes are treated more like the way in which states are treated. None of the sample documents that I had available expressly mention bond financing, so I drafted a new subsection, which includes a requirement that any such bond issue "must have the prior approval of the Tribal Council and may be subject to a referendum pursuant to the Constitution of the Hualapai Tribe." This section also includes a blank in the sentence saying that the total indebtedness of the Utility pursuant to bonds shall not exceed a certain amount.

It should also be noted that the Navajo Nation Code includes two additional subsections on borrowing money and accepting grants and loans, which seemed superfluous and have not be incorporated into this draft.

Section 204. Meetings of the Board. This section sets out requirements for meetings of the Board, which shall be at least quarterly, with an annual meeting on the same day and month each year. Paragraph (d) requires notice to Board members not less than five days prior to each meeting. This may be a sufficient amount of notice, or perhaps the a longer notice period should be required.

With respect to paragraph (f), the language in this section is adapted from the Gila River tribal utility Plan of Operations. The draft language does not say whether the meetings are open to the public. None of the sample documents I had available provide for meetings of the Board to be open to the public. This issue should be considered. Perhaps at least the annual meeting should be open to the public.

Section 205. Officers of the Board. This section sets out the duties of the Officers of the Board, and provides that the Board shall choose its own Officers on an annual basis.

Section 206. General Manager. This section says that the General Manager will be chosen by the Board, with responsibilities set out in a written contract and in policies adopted by the Board. It should be noted that the Navajo Nation code makes this appointment subject to approval by the Navajo Nation Council. Such a provision is not incorporated into this draft.

Section 207. Indemnification of Board Members and Employees. This section directs the Utility to indemnify any officer, employee or member of the Board for costs associated with litigation arising out of performing official duties, but not for activity beyond the scope of official duties.

Section 208. Bonds and Notes for Support of the Utility. This section is adapted from sections 25 and 26 of the Navajo Nation Code. This and the next section each include a limited waiver of tribal sovereign immunity. This section deals with bonds and promissory notes – basically, debt financing for facilities. A waiver of sovereign immunity is necessary if informed parties are going to enter into agreements with the Utility for debt financing. Section 209 addresses contractual obligations that do not involve bonds or notes.

Paragraph (b) allows suits in federal or tribal court for agreements with federal agencies. Paragraph (c) allows suits in tribal court for holders of bonds and notes.

Paragraph (d) is a limited waiver of sovereign immunity. This section includes a reference to Article VI of the Constitution of the Hualapai Indian Tribe, noting that a waiver of sovereign immunity pursuant to this section may require a referendum. Sovereign immunity is discussed in the Addendum at section II.C.4.

Section 209. Enforceability of Contracts. This section also includes a limited waiver of tribal sovereign immunity, something that is necessary if parties who understand tribal sovereign immunity are going to enter into contracts with the Utility. (25 U.S.C. § 81 requires a disclosure or waiver of sovereign immunity for any agreement that is subject to Secretarial approval.) An alternative would be to bring each such contract to the Tribal Council for a limited waiver of sovereign immunity specific to that contract, but, in my view, that option would be cumbersome for the operations of the Utility. In drafting this section, I had second thoughts about trying to deal with all the implications of this issue in the ordinance, and it occurred to me that the issues could be addressed separately from the enactment of the ordinance. So, this draft authorizes the Board to develop standard clauses for its contracts and take the standard clauses to the Council for approval. Subsection (a) authorizes a standard clause for business contracts (that is, contracts with vendors, consultants, other utilities and such); subsection (b) authorizes a standard contract clause for customer contracts. Enforceability of contracts with customers would be particularly important for interconnection agreements with small power producers.

As in section 208, this section includes a reference to Article VI of the Constitution of the Hualapai Indian Tribe, noting that a waiver of sovereign immunity pursuant to this section may require a referendum.

Section 210. Accounting and Fiscal Year. This section calls for the use of generally accepted accounting principles and says that the fiscal year shall be October 1 through September 30. The fiscal year of the Utility should be the same as that of the Tribe.

Section 211. Records, Inspections, and Audits. This section requires that the books, records and property of the Utility shall be available for inspection by authorized representatives of the Tribal Council.

Section 212. Insurance. This section requires the Utility to carry insurance, including liability, adequate and sufficient to protect the interests of the United States and the Tribe from loss by fire or other disaster.

An issue regarding tort liability should be considered, and is not expressly addressed in this draft. In light of the Tribe’s sovereign immunity, it would appear that we do not have to require insurance to cover tort liability unless we include a limited waiver of sovereign immunity for tort claims, and then limit the amount of possible recovery to the insurance coverage. The basic question is: does the Tribal Council want to make some provisions to provide some compensation to people who may suffer harm as a result of the Utility’s operations?

PART 3. OPERATIONS

Section 301. Operations Manual. The requirement for an Operations Manual is adapted from BIA regulations for the electric utilities operated by BIA, 25 C.F.R. part 175.

Section 302. Annual Budget. This section requires the General Manager to prepare an annual budget for the Utility and present it to the Board for its approval. To the extent that the Utility’s annual budget includes planned expenditures of any tribal funds or federal funds subject to control of the Tribal Council, the Utility’s budget must be approved by the Tribal Council.

This section could also include language saying that, to the extent the Utility’s budget includes planned expenditure of funds derived from receipt of payments for services in accordance with rates that have been approved by the Tribal Council, Council approval of that part of the budget is not required.

Section 303. Five Year Plan. This section requires the Board to prepare a five-year plan for the development of the Utility, which is to include both plans for the initial phase and the expansion phase as described in section 107 of the Ordinance. The five-year plan is to be updated on a biennial basis.

Section 304. Rates and Other Charges for Services. This section makes the Board responsible for setting rates charged for electric power services, subject to the approval of the Tribal Council. The Board is authorized to design rates to encourage energy efficiency and the interconnection of distributed generation facilities that use renewable resources. The topic of rate design is discussed in the Addendum at section I.C. See also note 41 in section II.A (discussing rate designs for mini-grids, drawing on experiences in less developed countries).

Section 305. Energy Conservation Services. This section authorizes the Utility to develop programs and provide services to help households, businesses, and other energy users to adopt energy efficiency and conservation measures.

Section 306. Solar and Renewable Energy Services. This section authorizes the Utility to develop programs and provide services to help households, businesses, and other energy users make use of solar energy and other renewable energy resources.

Section 307. Information and Educational Services. This section authorizes the Utility to develop programs and provide services to help energy users become more informed about the full range of issues relating to energy.

RESTRUCTURING, UNBUNDLING, AND GLOBAL WARMING:
HOW DO TRIBES FIT IN THE EVOLVING ELECTRIC POWER INDUSTRY?

Dean B. Suagee[*]

Outline

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[*] Of Counsel, Hobbs, Straus, Dean & Walker, LLP. This paper grew out of a draft legal options paper that was prepared as part of the Hualapai Tribe's electric utility project, a project that has been funded through an award of financial assistance to the Tribe from the U.S. Department of Energy. In reviewing the draft legal options paper, other members of the project team suggested that some of the details should be separated out and discussed in a background paper. The idea for a background paper evolved into this document, which is an addendum to the memorandum providing explanatory comments on the draft Ordinance. This topic raises a number of issues which have not to date been addressed in the scholarly literature of federal Indian law or in the literature on the electric utility industry. Accordingly, this paper has been prepared with the intent of sharing it with others in order to contribute to the discussion of the issues among Indian law scholars and practitioners. This paper does not include material that is specific to the Hualapai Tribe. Opinions expressed are those of the author.

The climate crisis driven by global warming presents a combination of danger and opportunity, as Al Gore has said in his movie and book AN INCONVENIENT TRUTH.[1] Tribal communities face many kinds of dangers of the climate crisis, such as losses in culturally important species of wildlife and plants resulting from changes in local ecosystems. Tribal communities ought to also share in the opportunities that can be realized by dealing with the sources of the problem. For the most part, the sources of the problem are the many ways in which we use fossil fuels. Dealing with these sources means becoming more energy efficient and moving toward the widespread use of solar and other renewable energy resources. Dealing with the sources in this way will offer opportunities to realize a range of benefits including jobs and business opportunities, national energy independence, regional and local self-reliance, relief from inflation in energy prices, enhanced environmental quality, and stabilization of the global climate.

In the United States, and throughout most of the world, electric power generating plants are the sources of a very large share of all the greenhouse gases emitted into the atmosphere. These power plants generally are owned by (or sell their output to) entities that are generically called "electric utilities" which sell the electricity to their customers. The electric utility industry has been going through some major changes in recent decades, and more changes can be expected as we come to grips with global warming.

In the United States, the electric utility industry has historically been regulated, for the most part, by the states. A handful of tribal governments have created their own electric utilities, and other tribes have shown some interest in doing so. This paper discusses some of the issues involved in developing a tribal electric utility, against the background of a changing industry and with some attention to how tribal governments can help tribal communities share in the opportunities presented by helping to solve the climate crisis.

I. OVERVIEW OF THE ELECTRIC UTILITY INDUSTRY

The electric utility industry as it currently exists is a big part of the problem of global warming. Generating electricity accounts for 42% of the U.S. share of CO_2 emissions, and the U.S., with 5% of the world's population, is responsible for 23% of the world's CO_2 emissions.[2] This means that 10% of all the CO_2 emissions worldwide come from electric power plants in the United States. This could change. The electric power industry could evolve into a big part of the solution to global warming. In broad terms, what needs to happen is fairly obvious: we need to become much more efficient in how

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[1] Al Gore, An Inconvenient Truth: The Planetary Emergency of Global Warming and What We Can Do About It (2006) (third page of the introduction, explaining the Chinese character for "crisis").

[2] AMERICAN SOLAR ENERGY SOCIETY, TACKLING CLIMATE CHANGE IN THE U.S. 168-69 (Charles F. Kutscher, ed., 2007), available at www.ases.org; *see also* Chuck Kutscher, *Confronting the Climate Change Crisis: What is the Evidence, and What Can We Do About It?, in* SOLAR TODAY, vol. 20, No. 4, p. 28, 31 (July/August 2006), with attribution to the U.S. Energy Information Administration.

we use electricity; we need to rapidly increasing the use of wind, solar, biomass, and other kinds of renewable energy resources for generating electricity; and we need to expand the use of non-electric solar technologies for energy services such as heating, lighting, and ventilation. Electric utilities could become leaders in making the renewable energy future a reality, and some utilities already are leading the way.[3] The extent to which others join in this movement will depend, in large part, on laws that are enacted at the federal and state level to provide mandates and incentives. As background for considering how tribal governments might fit into this picture, it should be helpful to provide a little detail on this industry as it presently exists, how it is regulated, a little background on its history, and a few observations on some of the current trends in its evolution.

A. Composition of the Utility Industry

The electric power industry has existed for more than a century, and a number different models have evolved for how electric utilities can be created, operated and regulated. The range of models includes: investor-owned utilities (IOUs); publicly owned utilities (municipal power companies, public power districts, state power authorities); rural electric cooperatives; and federal power authorities.[4] According to the Energy Information Administration (EIA), an agency within the U.S. Department of Energy (DOE), there are more than 3,170 electric utilities in the United States, including 239 IOUs, 2,009 publicly-owned utilities, 912 rural coops, and 10 federal utilities.[5] The IOUs collectively own about 75% of the generating and transmission capacity and serve about 75% of customers.[6] Rural electric cooperatives own about half of the nation's distribution lines.[7] There are also a small number of electric utilities that have been

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[3] *E.g.*, Sacramento Municipal Utility district (SMUD) is one leading example, *see* www.smud.org.

[4] *See generally* STEVEN FERREY, LAW OF INDEPENDENT POWER §§ 5:1 to 5:3. It should be noted that the terms used in this paper to describe these categories of utilities, while widely used, are not universal. Investor owned utilities, for example, are sometimes referred to as "public" utilities, in part because their stock is publicly traded, and many IOUs have the words "public service company" in their company name. This usage of the word "public," however, should be distinguished from utilities created and operated by cities and other units of local government, which are owned not by shareholders but rather by the citizens living and voting within the jurisdiction of a local government. The term "publicly-owned" is sometimes used to describe both municipals and state power authorities. Sometimes the rural coops are also included in this term, although that is not really accurate since they are private, non-profit membership organizations.

[5] U.S. Energy Information Administration, Electric Power Industry Overview (herein "EIA Overview"), available at: www.eia.doe.gov/cneaf/electricity/page/prim2/toc2.html. *See also* the websites of the American Public Power Association (APPA), www.appanet.org; the National Rural Electric Cooperative Association (NRECA), www.nreca.org; and the Edison Electric Institute (the association of IOUs), www.eei.org.

[6] EIA Overview, *supra* note 5.

[7] Ferry, *supra* note 4, at § 5:2.

created by tribal governments, although these tend to be ignored in federal and industry statistics.[8]

U.S. Electric Utility Industry Statistics, 2004

Type of Utility	Number	% of Total	Full-service customers	Delivery-only customers	Total customers	% of total
Publicly Owned utilities	2,011	61.4	19,628,710	6,125	19,634,835	14.4%
Investor-owned utilities	220	6.7%	90,970,557	2,879,114	93,849,671	68.9%
Cooperatives	884	27.0%	16,564,780	12,170	16,576,950	12.2%
Federal Power Agencies	9	0.3%	39,834	2	39,845	0.0%
Power Marketers	152	4.6%	6,017,611	0	6,017,611	4.4%
Total	3,276	100%	133,221,501	2,897,411	136,118,912	100%

Source: American Public Power Association, 2006-07 Annual Directory & Statistical Report compiled from Energy Information Administration form EIA-861, 2004 data.[9]

B. A Little Historical Background

Over the past two decades or so, there have been some dramatic changes in the electric power industry, but in some ways the industry still reflects some of the basic public policy decisions that were made nearly a century ago. Some of those historic policy decisions involve the issue of whether electric power is seen as a commodity to be sold as a source of revenue or as a public service to promote community development. As the industry has evolved in the United States, the resolution of this basic policy issue is that electricity is seen as both a commodity and a public service, with some models for operating in this industry emphasizing one view over the other.

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[8] E.g., the EIA Overview, supra note 5, does not mention tribal electric utilities, and it is not clear whether EIA simply overlooks the existence of tribal utilities or whether they might be included in one or another of the statistical categories. Ferrey, *supra* note 4, includes some discussion of tribal electric utilities, at § 5:4, and cites U.S. Department of Energy testimony before the Senate Committee on Indian Affairs on February 25, 2004, that there were, as of that date, four full service tribal utilities. *Id*. There are also a few Indian reservations where the U.S. Bureau of Indian Affairs operates an electric utility. *See* 25 C.F.R. part 175. The EIA Overview includes the BIA as one of ten federal electric utilities.

[9] The web address of the Energy Information Administration is www.eia.doe.gov. The information in the table is taken from the website of the American Public Power Association (APPA), the trade organization of municipal utilities: www.appanet.org. The information on the APPA site gives attribution to the EIA as the source of the information. The table does not include information on tribal electric utilities. A search of the EIA web site for "tribal utility" results in 16 entries, but only three tribal electric utilities. The Department of Energy testimony before the Senate Committee on Indian Affairs in 2004 that there are four full-service tribal electric utilities.

Other websites that are good sources of information on the electric utility industry include: the website of the National Rural Cooperative Association (NRECA): www.nreca.org; and the Edison Electric Institute (EEI), the association of investor-owned utilities: www.eei.org.

Historically, the electric utility industry has been seen as performing three basic functions: generation of electric power; transmission of power over high-voltage lines, and distribution of power to consumers. Throughout most of the 20th century, many electric utilities were vertically integrated, in that they performed all three of these functions. In the early decades of the 20th century, federal and state laws were enacted that treated the retail distribution of electricity as a "natural monopoly." In our capitalist economic system in which the prices of goods and services are supposed to be set in the free marketplace, the lack of competition is a problem. In the absence of a competitive marketplace, two basic policy questions were: (1) how would the utilities be owned? and (2) how would prices be determined? The first question – who would own the power companies – turns in part on whether electricity is seen as a public service or as a commodity to sell for a profit. If electricity is seen as a public service, then utilities ought to be owned by governmental entities and operated for the public good. If electricity is seen as a commodity to be sold for a profit, then power companies ought to be owned by investors (shareholders), and the profits ought to be paid out to those investors as dividends, or re-invested to yield greater profits.

In the early 20th century, many municipal governments created utilities, and many investor-owned utilities (IOUs) entered the industry, mostly in the larger cities where there was more money to be made. By the 1930s, the industry had evolved into a mix of publicly-owned and investor-owner power companies. IOUs were granted exclusive franchises within geographic service areas, in which they were obligated to provide service to all customers, and were made subject to regulation by state regulatory agencies commonly known as "public utility commissions" (PUCs) or "public service commissions" (PSCs).[10] The rates that IOUs charge their retail customers are generally set by PUCs, and, in most states PUCs also have authority over selecting the sites for new power plants and transmission lines. Publicly-owned utilities and cooperatives are generally not subject to regulation by state PUCs,[11] mainly because they are seen as being subject to control by the public through their institutions of local government, or their non-profit governance strucutres.

In the 1930s, the federal government began to become involved in the electric utility industry, as a regulator of the transmission of power in interstate commerce (through the Federal Power Commission, now known as the Federal Energy Regulatory Commission),[12] as a producer of power (through the Tennessee Valley Authority and Bonneville Power Authority), and as a source of financial assistance to bring electric

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[10] *See* Ferrey, *supra* note 4, at § 5:2.

[11] Twenty states regulate cooperatives, and seven regulate municipal electric utilities. EIA Overview, *supra* note 5.

[12] Congress gave the FPC this authority in response to a U.S. Supreme Court ruling that it was contrary to the Commerce Clause of the Constitution for a state PUC to regulate of the sale of power from a utility in one state to a utility in another state. Public Utilities Commission of Rhode Island v. Attleboro Steam & Electric Co., 273 U.S. 83 (1927).

power service to areas that were not being served by the IOUs (through the Rural Electrification Administration). Several decades later, Congress created other regional federal power transmission marketing agencies, including the Western Area Power Administration (WAPA), which was created in 1977 and serves a 15-state region with a large number of Indian reservations. The involvement of the federal government in the electric power industry has continued to grow, but a thorough discussion of the many of ways the federal government has been involved are simply beyond the scope of this article.

C. Setting the Price of Electricity

In the last decade or so there has been a trend to promote competitive markets in the electric utility industry, but the legacy of traditional regulatory rate-setting has not disappeared. Over most of the twentieth century, in light of the state-authorized status of the IOUs as monopolies, one of the main functions of state public utility commissions has been to be a substitute for the marketplace – determining what the IOUs can charge their customers for electric power. During the middle part of the twentieth century, the demand for electric power grew at a robust rate, doubling every decade from 1920 to 1970.[13] This translates to an average growth rate of about seven percent per year. While growth in demand tapered off after 1970, demand doubled again between 1970 and 1990. During that extended period of rapid growth, the main concern of the PUCs in approving rates for the IOUs was to do so in a way that let the IOUs keep up with the growing demand for electric power. In the basic approach to setting rates that emerged, called by terms such as "cost-of-service," "rate of return," or "rate base" regulation, rates were designed to ensure that the IOUs received enough revenue from their customers to be able to pay off their investments and make some profit on top of that. The depreciated value of the IOU's capital investments in power plants and transmission lines was its "rate base." Rates charged to customers were designed to yield revenue to the IOU without much regard for the signals that prices conveyed to customers. It was somewhat cheaper for IOUs to deliver power to customers that consumed large amounts, so large customers got cheaper rates, and those cheaper rates encouraged more consumption (a rate design called "declining block" – the bigger the block of power a customer bought, the more its rate went down).

This approach to setting rates provided an incentive to IOUs to build bigger and bigger plants, which from the 1960s into the 1980s, generally meant coal-fired and nuclear[14] power plants. Bigger power plants took longer to build, which meant that investment capital was tied up for longer periods of time before projects could be brought on line and sell power to customers. Because the IOUs were virtually guaranteed to

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[13] JAMES H. MCGREW, FERC: FEDERAL ENERGY REGULATORY COMMISSION 128 (American Bar Association Basic Practice Series, 2003).

[14] Orders for new nuclear plants stopped after the partial meltdown at Three Mile Island in 1979. Between 1972 and 1984, utilities spent more than $20 billion in planning and construction of some 115 nuclear power plants that were eventually abandoned by their sponsors. Ferrey, *supra* note 4, at § 3:21.

make money on their investments, investors continued to buy into them for their big, long term projects.

Setting rates so that utilities are assured a return on their capital investments is counter-productive for encouraging efficiency, both at the consumer level and the production level – if utilities were to help their customers use less power their revenues would decrease, which would not please their shareholders. In the 1970s and 1980s some state PUCs began to explore alternatives to traditional rate-base regulation, including peak-load pricing (e.g., "time-of-day" rates), a rate design strategy intended to shift demands for power away from peak load periods. The basic rationale for peak-load pricing is that largest component of the cost of delivering power was (and for the most part still is) the cost of building power plants to have the generating capacity available to meet demand. (Even for fossil-fuel fired power plants, the costs of fuel comprise a relatively small portion of the total cost, which is dwarfed by the cost of servicing the debt associated with building the power plants.) A federally-funded study released in 2006, the NATIONAL ACTION PLAN FOR ENERGY EFFICIENCY,[15] provides evidence that the regulatory regimes in which the rates for electric are set continue to provide disincentives for utilities to promote energy efficiency.

D. Non-Utility Generation

Some of the most dramatic changes in the electric power industry over the last three decades or so have to do with the development of generating facilities that are not owned by electric utilities. Such non-utility generators are typically smaller than utility-owned "central" power plants and, as they are interconnected with the grid at nodes that are "distributed" across the grid, this approach to adding generating capacity is sometimes called "distributed generation." The rise of non-utility generation has resulted from a number of factors, including federal support for technological development using renewable resources. Such federal support increased dramatically in the years after the 1973-74 embargo imposed by the Organization of Petroleum Exporting Countries (OPEC). In addition to direct federal funding, a range of federal and state tax credits were enacted to encourage investments in renewable energy technologies, and some such tax incentives are currently in effect. Federal support for renewables dropped off precipitously during the Reagan administration.[16] Conventional energy sources (fossil fuels and nuclear) have continued to receive the lion's share of federal research and

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[15] DEPARTMENT OF ENERGY & ENVIRONMENTAL PROTECTION AGENCY, NATIONAL ACTION PLAN FOR ENERGY EFFICIENCY (July 2006 at 2-2 – 2-11 (July 2006), available at: www.epa.gov/cleanenergy.

[16] According to the American Council on Renewable Energy (ACORE), federal funding for research and development in energy (renewable and non-renewable) peaked at about $8 billion in 1980, dropped to less than $4 billion by 1985, and has remained around $4 billion a year since then (converted to 2002 dollars). AMERICAN COUNCIL ON RENEWABLE ENERGY (ACORE), THE OUTLOOK ON RENEWABLE ENERGY IN AMERICA 22 (2007). A study published in 1985 reported that the total amount of federal subsidies for renewable energy, not counting large scale hydropower, was $1.7 billion in fiscal year 1984. H. RICHARD HEEDE, ET AL., THE HIDDEN COSTS OF ENERGY: HOW TAXPAYERS SUBSIDIZE ENERGY DEVELOPMENT 15 (Center for Renewable Resources, October 1985).

development funding, as well as various kinds of federal subsidies such as federal program expenditures, tax incentives, and loan guarantees.[17]

One of the key regulatory developments that contributed to the rise of non-utility power was the enactment in 1978 of the Public Utilities Regulatory Policies Act (PURPA),[18] which included provisions relating to the interconnection of IOUs and "qualifying facilities" (QFs),[19] a term that includes small power producers using renewable resources (solar, wind, biomass and geothermal) and co-generation facilities (which produce both electricity and heat that is put to use rather than wasted). Not all non-utility producers are "qualifying facilities," in some cases because they are larger than the size limits specified in PURPA, because they do not use renewable resources, or because they are not co-generators in that they not make use of their waste heat. The term "independent power producers" (IPPs) is used to describe non-utility projects that use renewable energy but which are not QFs; IPPs do not own transmission facilities and do not sell power at retail. The EIA uses the term "nonutility power producers" as a term that includes QFs, Cogenerators (whether or not they are QFs), IPPs, and Exempt Wholesale Generators (EWGs), a category authorized in 1992, which is described below.

PURPA's three main provisions on interconnection of IOUs and QFs were: (1) IOUs were required to buy power from QFs; (2) IOUs were required to provide back-up power to QFs; and (3) QFs were not to be treated as electric utilities (i.e., they were to be exempt from state regulation as utilities). These interconnection provisions of PURPA were implemented by state PUCs in accordance with regulations issued by the Federal Energy Regulatory Commission (FERC).[20] The basic concept in the first version of FERC's regulations on interconnection of QFs (based on the 1978 statutory language) is that IOUs should pay QFs for the electricity they buy based on what it would otherwise cost the IOU to generate the power, a concept known as "avoided cost."[21] This meant that if an IOU was planning to build an expensive new coal or nuclear plant, its avoided cost was to be based on that planned investment.

Avoided cost can be seen as a kind of wholesale price. While rates based on avoided cost were generally higher than many utilities wanted to pay out to small power producers (in part because they just did not want to have to bother with small power producers), such rates were still generally less than the rates charged to retail customers. Interconnection in which different rates are charged for power bought from and power sold to a QF requires rather sophisticated metering equipment. In some states, an alternative approach has emerged, called "net metering," in which power from the QF is

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[17] *See generally* Heede, *supra* note 16.

[18] Pub. L. No. 95-617, title II.

[19] Pub. L. No. 95-617, § 210 (codified as amended at 16 U.S.C. § 824a-3).

[20] 18 C.F.R. part 292.

[21] For an extensive discussion of avoided cost, *see* Ferrey, *supra* note 4, at Chapter 7.

valued at the same price as power sold to the QF. In net metering, the meter simply runs backward when the QF is feeding power into the grid. Municipal utilities and rural coops were not subject to the interconnection requirements of PURPA, and some of them strongly resisted interconnection with small power producers. Now some municipal utilities and rural coops have policies to encourage interconnection with small power producers, but those that do have generally adopted such policies on their own without having been required to by law.

The statutory mandate for interconnection of QFs was modified in the Energy Policy Act of 2005.[22] Briefly, FERC is directed to determine whether the marketplace is sufficiently competitive such that the QF is able to sell its power; if so, then utilities are relieved of the obligation to buy it. FERC recently issued a final rule to implement this amendment to PURPA.[23] Pursuant to this final rule, there is a rebuttable presumption in some regions that QFs do have nondiscriminatory access to markets, except that, for QFs of 20 MW or less, there is a rebuttable presumption that they do not. FERC has also published a final rule implementing related amendments to PURPA, including a change in the criteria for cogeneration facilities to be treated as QFs by requiring that the energy output be used in a beneficial and productive manner.[24] Along with many other provisions of the 2005 Energy Policy Act, the new rules in small power producers have implications for the ongoing evolution of the electric utility industry.

E. Competition and "Unbundling" Electric Utilities

In the Energy Policy Act of 1992, Congress authorized a new kind of entity to enter into the marketplace, a class known as "exempt wholesale generators" (EWGs).[25] Unlike QFs, these EWGs are not required to use renewable fuels, and IOUs are not required to buy power from them. The main legal benefit given to them is that they are not regulated as electric utilities. This change in the law was a key factor in the growth of natural gas generating plants not owned by utilities. Since the mid-1990s, this kind of natural gas plant has accounted for most of the expansion in electric generating capacity in the U.S.

FERC issued a number of orders in the 1990s intended to promote competition in interstate wholesale markets for electricity by promoting "open access" to transmission

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[22] Pub. L. No. 109-58, § 1253, 119 Stat. 594 (2005).

[23] Federal Energy Regulatory Commission, New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities, Final Rule, Order on Rehearing, Docket No. RM06-10-001, Order No. 688-A (June 22, 2007), revising Order No. 688, 71 Fed. Reg. 64342 (Nov. 1, 2006), FERC Stats. & Regs. ¶ 31,233 (2006) (Final Rule) (to be codified at 18 C.F.R. part 292).

[24] Federal Energy Regulatory Commission, Revised Regulations Governing Small Power Production and Cogeneration Facilities, final rule, 71 Fed. Reg. 7852 (Feb. 15, 2006); same, final order on rehearing, 71 Fed. Reg. 30585 (May 30, 2006).

[25] Pub. L. No. 102-486, 106 Stat. 2776 (1993).

lines. Two of the key ones were Order No. 888,[26] which sought to "unbundle" the sale of electricity at wholesale from the transmission of electricity, and Order No. 889,[27] which sought to ensure open access to transmission facilities. The unbundling of generation from transmission has led to the creation of independent system operators (ISOs), entities that manage transmission systems but have no financial stake in generating facilities.[28] In 1999, FERC issued Order No. 2000 on Regional Transmission Organizations (RTOs),[29] a term that includes both non-profit ISOs and for profit entities.[30] There are gray areas and unresolved issues regarding the operation and control of ISOs and RTOs.[31] FERC has issued several other decisions and rules relevant to the restructuring of the electric utility industry, but those rulings are not discussed in this article. FERC recently issued a Final Rule codifying and, in certain respects, revising its standards for "market-based rates" for wholesale sales of electric energy by public utilities.[32]

During the 1990s, many state legislatures and PUCs adopted policies to promote competition in retail markets for electricity, generally based on the rationale that such competition would help to hold down the prices charged to consumers. Such policies can be seen as an endorsement of the view that electricity is a commodity rather than an essential public service. The shift toward promoting competition was accompanied by relaxing or eliminating mandates that had been imposed on IOUs to establish programs to help consumers adopt energy conservation measures.[33]

The growth in natural gas plants operated by EWGs led to a regulatory decision by FERC to change the rules on determining avoided cost for buying power from QFs. For many utilities, natural gas power from an EWG had become the practical standard of comparison rather than building a new coal or nuclear plant. In the mid-1990s, the California PUC had developed an aggressive plan to expand the use of renewable energy QFs in the state, but FERC issued a ruling that the PUC had gone too far. FERC ruled that in setting the rates paid by IOUs to buy power from QFs, the PUC had to take into

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[26] FERC, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities; Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996).

[27] Open Access Same-Time Information System and Standards of Conduct, Order No. 889, FERC Stats. & Regs. ¶ 31,035 (1996).

[28] *See generally* Ferrey, *supra* note 4, at § 10:87.

[29] Regional Transmission Organizations, Docket No. RM99-2-000, 89 FERC ¶ 61,285 (12-20-99).

[30] *See generally* Ferrey, *supra* note 4, at § 10:91.

[31] *See generally* Ferrey, *supra* note 4, at § 10:92.

[32] Market-Based Rates For Wholesale Sales of Electric Energy, Capacity and Ancillary Services, Docket No. RM 04-7-000, Order No. 697 (June 21, 2007) (to be codified at 18 C.F.R. part 35).

[33] *See* National Action Plan for Energy Efficiency, *supra* note 16, at Ch. 2; *see also* Ferrey, *supra* note 4.

account the relatively cheap power from EWG natural gas plants.[34] As a result, projected investments in renewable energy in California dropped off considerably. California experienced a crisis in 2000, when consumers faced catastrophic increases in the prices charged for electricity, and some observers have concluded that among the factors contributing to the crisis were the regulatory preference for natural gas and de-regulation of the electricity market. In the wake of that crisis, "California has backed away from its retail competition program and several other states have delayed or repealed the planned implementation of their retail choice programs."[35]

F. Where Do Tribal Governments Fit?

In a subject matter that has largely been regulated by states and in which possible roles for tribal governments have been largely overlooked, how should tribes fit into this picture? Given that the electric utility industry is responsible for such a large share of U.S. CO_2 emissions, and given that reducing these emissions will require substantial expansion of distributed generation as well as major efforts to reduce demand for power through energy efficiency and demand side management, the electric utility industry will be going through some major changes in the next decade or so. What roles should tribal governments be playing in helping to shape the evolution of the industry?

II. SOME OBSERVATIONS ON TRIBES AND THE UTILITY INDUSTRY

Traditional principles of federal Indian law, including the doctrine of inherent tribal sovereignty,[36] suggest that tribal governments ought to be able to become engaged in the electric utility industry within their reservations in much the same range of ways that states and local governments do elsewhere in the United States. Tribes should be able to examine the basic policy issues and make their own decisions, even if their decisions are different from decisions made by the states. A tribe should be able to create governmental institutions to engage directly in whatever aspects of the industry that tribal officials believe will serve the interests of reservation communities, e.g., generation, transmission, distribution, energy efficiency, or other kinds of energy-related services. Alternatively, or in combination, a tribe should be able to create regulatory institutions and promote a free enterprise approach to energy services.

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[34] Southern California Edison Company and San Diego Gas & Electric Company, 70 FERC ¶ 61,215 at 61,677-78, reconsideration denied, 71 FERC ¶ 61,269 at 62,078 (1995) (finding that the determination of avoided cost must take into account "all sources").

[35] Earle H. O'Donnell and Jane E. Berger, *Keeping the Faith: Default Service and Competitive Retail Electric Markets*, 19 NAT. RESOURCES & ENVT. 25 (2005).

[36] *See generally* COHEN'S HANDBOOK OF FEDERAL INDIAN LAW § 4.01 (2005 ed.).

But, of course, tribes must contend with a body of court decisions over the last three decades that have found implicit limits on tribal sovereign powers[37] and which have upheld state governmental authority within reservations, particularly with respect to nonmembers of the local tribe and with respect to land that is no longer in trust status (or which may be treated as the functional equivalent of non-trust land).[38] In a subject matter that has traditionally been regulated at the retail level by state governments, and in which there is a lot of money involved, there are some litigation risks for tribes that venture into this subject matter.[39] Such risks should be taken into account by tribal officials in making decisions on how to become engaged in this industry.[40] Federal laws and policies to deal with global warming could include measures to reduce or eliminate such risks for tribes that want to be part of the solution.

A. Functions for a Tribal Electric Utility or Similar Entity

A tribal government could create an electric utility to perform one or more of the functions performed by traditional electric utilities: generation, transmission and distribution. In addition to the three basic functions, many electric utilities have taken on some additional functions, including: programs to promote energy conservation and efficiency and other kinds of "demand side management"; interconnection of small power producers; and investments in independent power systems (generally in the service areas of other utilities). For most electric utilities, these additional functions are extraneous to their core missions, and some functions were taken on only because required by federal or state law. For example, utility conservation programs were typically carried out in response to mandates under state laws, and in some cases out of enlightened self-interest. Since the mid-1990s, utility spending for conservation programs has generally declined (generally in conjunction with unbundling of utility services), and some states have responded by adding fees to electric bills to direct some money into "public benefit funds."

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[37] *See generally* COHEN'S HANDBOOK, *supra* note 36, at § 4.2; ; *see also* John P. LaVelle, *Implicit Divestiture Reconsidered: Outtakes from the* COHEN'S HANDBOOK *Cutting-Room Floor*, 38 CONN. L. REV. 731 (2006); Dean B. Suagee, *The Supreme's "Whack-a-Mole" Game Theory in Federal Indian Law, a Theory that Has No Place in the Realm of Environmental Law*, 9 GREAT PLAINS NAT. RES. J. 90 (2002).

[38] *See generally* COHEN'S HANDBOOK, *supra* note 36, at §§ 6.1, 6.3.

[39] In one case, in which a tribe sought to buy power from an electric utility other than the utility in whose service area its reservation was located, a service area authorized by the state public utilities commission, the federal courts ruled that a tribe did have the power to choose a provider of electricity service to tribally owned businesses on trust land, but that the tribe did not have the authority to regulate electric utility service within its reservation. Baker Electric Cooperative, Inc. v. Chaske, 28 F.3d. 1466 (8th Cir. 1994), *on remand*, Devils Lake Sioux Tribe v. North Dakota Public Service Commission, 896 F.Supp. 955 (D.N.D. 1995). These cases are discussed in Ferrey, *supra* note 4, at § 5:7.

[40] Some observations on this issue are offered in section II.C.1. of this article.

The mission of a tribal utility might be conceived more broadly, such as to make energy-related services and benefits available to reservation residents, with an emphasis on promoting energy efficiency and locally available renewable resources. With such a broad mission, the distribution of electric power might just be a part of the overall package of services. The utility might put an emphasis on programs to help customers install distributed generation facilities, such as roof-top photovoltaic arrays, which could be owned by either the utility or the customers. Or they might be owned by third-party investors who would take advantage of the tax credits. Ownership might be transferred from the utility to the customer over time though a lease-purchase agreement.

The utility might put an emphasis on providing service to areas that do not presently have access to the power grid, building and operating mini-grids for such areas, which could be stand-alone systems or could be interconnected with the grid. If the tribal utility were to promote the development of such mini-grids, it might want to look at experience in less-developed countries for ideas about how to set prices for power from the mini-grid and policies on interconnection of distributed generation facilities to the mini-grid.[41]

The utility might include a building design assistance program to help customers incorporate energy efficiency and solar design techniques into new construction. New buildings could be not just "zero-net energy" but, rather, net energy producers, pumping more power into the grid than they consume. The utility might recruit joint venture partners from private industry to help provide assistance and to help make investment capital available. The utility could put an emphasis on schools and other educational institutions, and help to design and carry out energy education programs with hands-on aspects. For example, a school could integrate solar energy projects with the approach of the "edible schoolyard"[42] in which school children help grow some of the food that they eat in their school lunches. Schools in tribal communities could incorporate solar greenhouses attached to school buildings as parts of their edible schoolyards.

In deciding among the various functions that a tribe might want to take on, there are many factors to consider, such as the adequacy of the existing utility service, relationship with the current service provider, costs associated with taking over the system, the locally available resource base, and the broader political framework. The broader context includes federal and state legislation, such as: existing state laws that

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[41] *See* Xiaodong Wang, *Legal and Policy Frameworks for Renewable Energy to Mitigate Climate Change*, 7 (Issue No. 2) SUSTAINABLE DEVELOPMENT LAW & POLICY 17 (2007). Dr. Wang suggests that rate structures for mini-grids should: (1) "Recover at least O&M&M [operation, maintenance and management] costs"; (2) "Reflect cost structure – a high fixed charge (higher than typical tariff structures applied in large grid systems) to reflect O&M&M costs, a variable charge to reflect fuel costs, and a levelized capital charge [to] partially reflect capital investment costs"; (3) Remain below consumers' ability to pay." *Id*. at 19.

[42] *See* www.edibleschoolyard.org.

establish renewable portfolio standards for regulated utilities;[43] the federal incentive in section 203 of the 2005 Energy Policy Act[44] for federal agencies to purchase power from tribal renewable energy projects; possible future legislation to create a "cap and trade" program to reduce CO_2 emissions, and various other kinds of incentives for renewables (including tax incentives unavailable to tribes but potentially useful for business partners of tribal utilities).

A tribe might want to do some parts sooner and other parts later. For example, a tribe with a substantial wind power resource might be able to bring that resource into operation and use the revenue stream to subsidize energy efficiency services or the purchase of the existing power grid within the reservation. A tribe might create a utility with a broad mandate but with the expectation that it will start small and expand its range of activities over time. In such phased development, there could be decision points at which tribal council approval is necessary. Another approach would be to create more than one entity, perhaps one with a conservative mission of providing reliable retail electric power service at reasonable rates and another with a more entrepreneurial mission of bringing renewable energy projects into operation using investment strategies that entail more risk than is consistent with the conservative mission of a distribution utility. In that scenario, the mission of the entrepreneurial entity might be described as including the marketing of risk to investors willing to accept it. In light of the range of benefits that could be realized in tribal communities through renewable energy development and the associated offsets for CO_2 emissions, renewable energy in Indian country should be able to make the grade among investments that are screened for social and environmental responsibility.

B. Form of Organization

There are several ways in which a tribal electric utility can be brought into existence as a legal entity. As discussed in part I of this paper, there are several models for the legal existence of an electric utility in the United States, and some of these models could be adapted for use by a tribal electric utility. There are only a few existing tribal electric utilities. Analysis of the organizational documents of some of the existing tribal electric utilities supports an observation that the options for the form of legal existence do not appear to have been thoroughly explored.[45] In any event, given the sweeping changes

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[43] *See generally* Wang, *supra* note 41; *see generally* GLOBAL CLIMATE CHANGE AND U.S. LAW (Michael B. Gerrard, ed, 2007).

[44] Pub. L. No. 109-58, § 203 (to be codified at 42 U.S.C. § 15852). In addition, the long section 503 in the "Indian Energy" title of the 2005 Act includes a provision (to be codified at 25 U.S.C. § 3505) that authorizes the Western Area Power Administration (WAPA) to purchase power from tribes to meet firming and reserve requirements and allows WAPA power allocations to tribes to be used to meet firming and reserve requirements for Indian-owned projects on Indian lands.

[45] E.g., the tribal statute creating the Navajo Tribal Utility Authority and the Tohono O'odham Utility Authority both say that the utility authority is supposed to act like a public service company, and organizational documents for two other tribal utilities in Arizona also use such language. A public service

that are taking place within the electric utility industry, the option of simply copying the form of existence from one of the existing tribal electric utilities might result in limiting the ability of a new tribal utility to adapt to changes in the industry (and to help shape changes in the industry).

To recap the varieties of electric utilities in the industry as it currently exists (not counting the handful of tribal utilities), there are: investor owned utilities (IOUs); publicly owned utilities (mostly municipal utilities); rural electric cooperatives; federal power agencies and power marketers. One of the key distinctions is whether a utility is an institution of government or a private corporation. Another key distinction that applies to the non-governmental utilities is whether they are organized as for-profit corporations (the IOUs and the power marketers) or as non-profits (the rural cooperatives). A tribal government could create a utility using any of these three basic distinctions: governmental institution, for-profit corporation, or non-profit corporation. These options are discussed in this section; some of the factors that should be considered in making a choice are discussed under heading C.

It should also be noted that an alternative strategy would be to work from within the structure of the existing utility serving a tribe’s reservation with the objective of, in effect, taking it over from within. Such an approach may be realistic for some tribes, especially where the service provider is a rural electric cooperative and where the service area of the cooperative is such that many or most of the customers are tribal members. If a reservation is served by an IOU, another theoretical possibility would be to acquire enough stock to have meaningful input into the policies of the IOU. Advocacy in corporate governance does not necessarily require a large amount of stock.

For some purposes, the form of legal existence may not matter very much: for most practical purposes a utility set up as a governmental entity might carry on its business much like one set up as a corporation chartered by the Tribal Council, whether for-profit or non-profit. A tribal electric utility might be seen as a tribal “enterprise,” a term with several meanings, one of which is “a company organized for commercial purposes; a business firm.”[46] In common usage the term “enterprise” carries implications of being organized for profit, which is not necessarily the case for an electric utility. The term “enterprise” might also be understood in a more general sense as a quasi-independent entity created by the Tribal Council with the intent that it will generate enough revenue from its operations that it will be self-supporting and will not need recurrent subsidies from the Tribal Council.

With respect to some factors, however, the form of legal existence does make a difference. In particular, in my view, the regulatory context and tax implications

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company, however, is an investor owned utility (IOU), which is a for-profit corporation and, as such, has duties to its shareholders and a governance structure framed by a body of state and federal law. In my view, the IOU model is not the most appropriate model for a tribal electric utility.

[46] Webster’s Encyclopedic Unabridged Dictionary of the English Language 476 (1994).

discussed under heading C, “Some Factors To Consider,” suggest that the governmental institution option will generally be favorable for a general purpose utility.

In light of the changes occurring within the electric utility industry, a tribal government might not want to limit itself to adapting one of the existing models. The existing models are changing as the traditional functions become “unbundled.” In becoming engaged in the electric utility industry, tribal officials might want to consider creating more than one entity, in effect unbundling certain functions from the outset. For example, a tribe might want to establish a conventional distribution utility, and it might want to limit its power production to renewable energy projects that sell power to off-reservation utilities. While a single entity could do this, it might work better to create two or more distinct entities, each of which would focus on different functions. Alternatively, the tribal government could create a single entity but do so in a way that encourages other entities to become engaged in various aspects of implementing a renewable energy and energy efficiency program.

1. Institution of Tribal Government

The creation of a tribal electric utility as an institution of tribal government is a relatively simple option, which can be brought about by the enactment of tribal legislation. This form of organization presents a range of political and governance issues, which are discussed below in section C.3. The municipal utility model that is widespread in non-Indian America appears to be a model from which such a tribal utility could be adapted. It should be noted, however, that municipal utilities operate within a framework of state legislation, a framework that varies from state to state. Such state laws do not apply to tribal institutions, but a tribe creating a utility might want to examine such laws to see if there are concepts that would be appropriate to enact as tribal law. This is a subject matter in which some attention from Indian law scholars would be beneficial.

2. A For-Profit Corporation

A for-profit corporation is the basic form of organization for an investor-owned utility (IOU). While an IOU provides a public service, such a corporation is owned by its shareholders, and the primary mission of any IOU is to provide a return on the investments made by its shareholders.

A tribal electric utility could be created using this model. A corporation has its own distinct legal existence, though a corporation that is wholly owned by a tribe or chartered under the Indian Reorganization Act shares the legal identity of the tribe for some purposes. The range of options from which a tribe could choose include creating a corporation under federal, state, or tribal law. The federal law option means obtaining a federal charter pursuant to section 17 of the Indian Reorganization Act.[47] Incorporation under state law means accepting an existing body of state law, including a code that establishes the basic law for incorporating within a state. If a tribe has adopted a code

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[47] Codified at 25 U.S.C. § 477.

governing the establishment of corporations, a tribal utility could be established under such a tribal code. In the absence of such a tribal code, incorporating under tribal law would require the Tribal Council to approve a charter for the corporation. The tax implications for corporate options are discussed under heading C.

3. A Non-Profit Corporation

The other generic category of corporate existence is non-profit status. The rural electric cooperatives use this form. As with the for-profit option, such a corporation can be created under tribal law or state law. The tribal law option is easier if a tribe has enacted a code governing non-profit corporations. Even if a tribe chooses the governmental entity or for-profit form to create a utility, the non-profit form may be a useful for some of the functions that a tribal utility might serve. A non-profit could carry out educational programs to complement a utility's operations. A non-profit that has tax-exempt status could seek funding from foundations and other sources to provide assistance to low-in come families in tribal communities, including assistance with energy efficiency measures and installation of renewable energy systems such as roof-top photovoltaic arrays.

C. Some Factors To Consider

If we think of a new utility as an enterprise in the general sense of an entity that is expected to generate enough revenue to cover its costs, then the literature on tribal enterprises can serve to help identify the factors that should be considered and to add some detail to the range of options that are available for the legal form of a tribal enterprise.[48] In choosing among the options for a form of organization, some of the factors that need to be considered include: tax implications; governance issues; political issues; and issues relating to the expectations of commercial partners and lenders, including the ability to have agreements enforced which implicates tribal sovereign immunity. In my view, issues relating to regulatory jurisdiction generally counsel in favor of choosing to use a governmental entity form, and so this section of the paper leads off with a discussion of that set of issues.

1. Regulatory Jurisdiction

In creating a tribal utility, a tribal legislature would presumably want the utility to be subject to tribal regulatory jurisdiction and not subject to state jurisdiction. Electric utilities have historically been regulated mainly by the states. There are Supreme Court decisions finding that states can exercise regulatory and taxing jurisdiction within Indian country without express congressional authorization, particularly with respect to the conduct of non-Indians.[49] In the absence of federal legislation affirming that electric

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[48] The discussion in this draws upon COHEN'S HANDBOOK, *supra* note 36, particularly chapter 21. Numerous other sources are cited therein.

[49] *See generally* COHEN'S HANDBOOK, *supra* note 36, at §§ 6.1, 6.3.

utility regulation is a subject within the inherent sovereignty of tribal governments,[50] or delegating federal power, a tribal assertion of regulatory jurisdiction could face litigation risks. Tribes should anticipate having to show that that such an assertion of regulatory authority is within the realm of inherent sovereignty. If the state asserts regulatory authority, the tribe might have to argue that, even if the state has the sovereign power to regulate within the reservation, to allow it to do so would infringe on the tribe's right of self-government.[51]

Risks of this kind of litigation can be reduced by choosing the option of setting up the utility as an institution of tribal government. Advantages of this option include: (1) it allows the argument in support of inherent tribal sovereignty to be framed in terms of the tribe managing tribal resources and governmental subdivisions, rather than regulating nonmember third persons; (2) to the extent that a tribal entity provides energy services to nonmembers though contractual relationships, such contracts can be drafted to preserve inherent tribal sovereignty pursuant to the "consensual relations" exception to the "general proposition" of *Montana v. United States*,[52] and (3) the tribe's sovereign immunity operates to block a direct assertion of concurrent state regulatory jurisdiction. These advantages would seem to hold if the tribal utility is the only retail provider of electricity. Of course, the tribal utility would likely have contractual relations with other utility industry entities that are subject to state regulation, which suggests possibilities for a kind of collateral assertion of state jurisdiction. In addition, private parties within the reservation may seek to buy power from utilities other than the tribal utility, particularly in states that encourage retail competition.

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[50] Pub. L. No. 102-486, title XXVI, § 2605 (formerly codified at 25 U.S.C. § 3505) Included statutory language supportive of tribes pursuing "vertical integration" in the development of their energy resources. Such language might have been argued to be evidence of congressional affirmation that regulating energy resources, including electricity, is within the scope of inherent tribal sovereignty. That statutory language in the 1992 Act was repealed with the enactment of the Energy Policy Act of 2005. Section 503 of the 2005 Act amends Title XXVI of the 1992 Energy Policy by replacing statutory language previously codified at 25 U.S.C. §§ 3501 – 3506 with new statutory text. *See* Dean B. Suagee, *The "Indian Energy" Title of the 2005 Energy Policy Act – An Overview*, American Bar Association, Native American Resources Newsletter, Vol. 4, No. 1, at 5 (May 2007), available at www.abanet.org/environ/committees/nativeamerican/newsletter/.

[51] The infringement test, which the Supreme Court first applied in Williams v. Lee, 358 U.S. 217 (1959) (holding tribal court had exclusive jurisdiction over a matter involving a non-Indian), was given rather perfunctory treatment by the Court in Nevada v. Hicks, 533 U.S. 353, 362-63 (2001) (holding tribal court implicitly divested of jurisdiction over tort matter involving state law enforcement officers, and finding that state's on-reservation criminal investigation did not infringe on tribal self-government). *See* LaVelle, supra note 37, at 766.

[52] 450 U.S. 544, 564-66 (1981). The "general proposition" of *Montana* is that "the inherent sovereign powers of an Indian tribe do not extend to nonmembers of the tribe." *Id*. at 565. The Supreme Court applied the "consensual relations" narrowly in *Atkinson v. Shirley*. 532 U.S. 645, 655-57 (2001). See LaVelle, *supra* note 37, at 750.

2. Tax Implications

In choosing a form of existence, tax implications must be considered. The Tribe itself is a non-taxable entity,[53] and a utility established as an institution of tribal government would share in the non-taxable status of the Tribe. A tribe's tax exemption applies regardless of where the activities generating income take place.[54] In other words, it does not matter whether the activities are located on trust land or within reservation boundaries. A tribal corporation chartered under section 17 of the Indian Reorganization Act[55] is covered by the tribe's tax exemption.[56] The creation of a section 17 corporation involves a rather complex process including BIA approval, operation is somewhat cumbersome, and dissolution requires an act of Congress.[57]

Tribal corporations organized under state law are taxable.[58] A tribal corporation organized under state law as a non-profit corporation could qualify for tax exempt status, although it would have to apply to the Internal Revenue Service (IRS) and show that it meets the criteria. The tax status of a corporation chartered under tribal law is subject to some uncertainty. There is no generally applicable ruling by the IRS, although there have been case-by-case determinations that a corporate entity wholly owned by a tribe that is an integral part of the tribe is covered by the tribe's tax exempt status.[59]

These tax implications suggest that, for tax purposes, it would be preferable to create the tribal electric utility as an institution of tribal government. The option of creating it as a corporation chartered under tribal law might also achieve the objective of tax exempt status, but this option would require more work to bring the entity into existence and might also require seeking a private letter ruling from the IRS. The option of chartering a corporation under IRA section 17 would ensure tax exempt status, but the effort involved in creating such a corporation may not be worth the effort. If a tribe already has such a corporation, it might make sense to make electric utility services part of its mission; such a decision would have to consider such a tribe's particular issues.

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[53] Rev. Rul. 67-284, 1967-2 C.B. 55 (Indian tribes are not taxable entities). *See generally*, Cohen's Handbook § 8.02.

[54] Rev. Rul. 94-16, 1994-1 C.B. 19.

[55] Codified at 25 U.S.C. § 477.

[56] Rev. Rul. 94-16, 1994-1 C.B. 19. Tribal corporations organized under section 3 of the Oklahoma Indiana Welfare Act, 25 U.S.C. § 503, are also covered by the tribe's tax exempt status. Rev. Rul. 94-65, 1994-2 C.B. 14.

[57] *See* COHEN'S HANDBOOK, *supra* note 36, at § 21.02[1][b].

[58] Rev. Rul. 94-16, 1994-1 C.B. 19.

[59] *See* COHEN'S HANDBOOK, *supra* note 36, at § 8.02[2][a], citing IRS PLR 200409033 (tribally chartered corporation); IRS PLR 200148020 (tribal college chartered under tribal law).

There are other tax implications that should also be considered. Most of a tribal utility's business partners and customers will not be tax exempt. To the extent that federal and state policies supporting investments in renewable energy and energy efficiency are carried out through tax incentives, such incentives will be of no direct benefit to the tribal utility. Such incentives, however, could be of direct benefit to the tribal utility's business partners and customers, and, as such, could be key mechanisms in increasing the use of renewable energy within the Reservation. The importance of this point is that the tribal utility could be created with a mandate to help its business partners and customers make use of federal and state tax incentives.

3. Governance and Political Issues

Creation of a tribal electric utility presents a range of political and governance issues, including the basic issue of how much control the tribal governing body should have over the utility, or, seen from the perspective of the utility, how much independence the utility should have from the tribal council. As a practical matter, there is a need for management with clear authority regarding day-to-day operations, with some degree of insulation from political interference. There is also a need for oversight of day-to-day management, and there is a need for oversight regarding policy issues, such as priorities among various missions and the policies embedded in rate designs. The oversight of day-to-day management can be provided by a body such as a board of directors, and the oversight regarding policy issues can be provided by the tribal governing body. It is probably not a good idea for the tribal governing body to set itself up to provide oversight of day-to-day operations.

This set of issues arises regardless of the form of organization that is chosen, although the resolution of these issues does turn, in part, on the form of organization. If the governmental entity form is chosen, then at one end of the spectrum, a tribal governing body could choose to operate an electric utility directly, without establishing any kind of separate organization structure.[60] At the other end of the spectrum, a tribal governing body could create a governmental institution that is an independent agency, with its own governing body, subject to tribal law but not subject to tribal council oversight of its day-to-day operations; rather, tribal regulatory oversight could be conducted by a tribal utilities commission comparable to those of the states. (Some tribes have utilities commissions that regulate water and sewer service, and in such cases expanding the mandate of such a commission is an option.) There are gradations in between the ends of the spectrum, variations on the extent to which the tribal council exercises control over the utility's governing body.

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[60] There is one example of this, Metlakatla Power and Light, which has as its form of legal existence the Tribal Council of the Metlakatla Indian Community doing business as Metlakatla Power and Light. The reservation of the Metlakatla Indian Community consists of two islands and surrounding waters off the coast of southeastern Alaska, and the tribal electric utility is not interconnected to the power grid on the mainland.

There are also issues relating to the expectations of commercial partners and lenders, including the ability to have agreements enforced. If a tribe operates a utility as a governmental institution, then the expectations of partners and lenders have implications for tribal sovereign immunity.

4. Sovereign Immunity and Waivers

A tribal utility that is a governmental entity or a tribal enterprise will be covered by the tribe's sovereign immunity from suit in federal or state court.[61] The Supreme Court has "held that sovereign immunity extends to the tribe's commercial as well as governmental activities, and [has] reaffirmed that immunity extends to activities occurring outside of Indian country."[62] Tribal sovereign immunity "does not extend to tribally chartered corporations that are completely independent of the tribe."[63] The charters for tribal corporations created under section 17 of the Indian Reorganization Act typically include a "sue or be sued" clause, but "[m]ost courts have reasoned that tribal adoption of a charter with such a clause simply creates the power in the corporation to waive immunity, and that adoption of the charter alone does not independently waive tribal immunity."[64]

If a tribal utility is covered by sovereign immunity, limited waivers of immunity will generally be necessary in order to conduct business in the electric utility industry. Other utilities and private companies doing business with the tribal utility will have reasonable expectations that their contracts are enforceable, which will generally require waivers of immunity. In drafting waivers, tribal attorneys should be sure to review relevant tribal law as well as relevant federal and state court decisions; some tribal constitutions include provisions on sovereign immunity, such as procedural requirements for waivers.

In the context of the evolving electric power industry, unusual questions may arise. For example, an investor in a renewable energy project located on tribal land might want a security interest backed by an enforceable right to take possession of the project to ensure its proper operation. Renewable energy development in Indian country would appear to be suitable for attracting socially responsible investment, but investors will need to know that their agreements are enforceable.

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[61] *See generally* COHEN'S HANDBOOK, *supra* note 36, at § 7.05.

[62] *Id*. at § 7.05[1][a], *citing* Kiowa Tribe v. Manufacturing Technologies, Inc., 523 U.S. 751, 760 (1998).

[63] COHEN'S HANDBOOK, *supra* note 36, at § 7.05[1][a], *citing* Dixon v. Picopa Constr. Co. 772 P.2d 1104, 1109 (Ariz. 1989). *See also* Allen v. Gold Country Casino, 464 F.3d 1044, 1046 (9th Cir. 2006), *cert. denied* (holding tribal sovereign immunity applies to tribal casino, in that the "question is not whether the activity may be characterized as a business, which is irrelevant under *Kiowa*, but whether the entity acts as an arm of the tribe so that its activities are properly deemed those of the tribe."

[64] COHEN'S HANDBOOK, *supra* note 36, at § 7.05[1][c] (collecting cases at n. 376).

5. Tax Exempt Bond Financing

Tribal governments may want to consider the possibility of using bonds to finance investments made by the Utility. The Indian Tribal Government Tax Status Act[65] authorizes tribal governments to issue bonds in much the same way that state and local governments issue bonds to finance investments in construction of the infrastructure to deliver governmental services, such schools, roads, and government buildings. Bonds issued by tribal governments must be for "essential governmental functions" in order for the interest paid on the bonds to be tax exempt. Commercial or industrial activity does not qualify for bond financing. The Internal Revenue Service recently published an advance notice of proposed rulemaking on this issue,[66] in which IRS announced its intent to develop rules to clarify the term "essential governmental functions."

Investments in a power grid and generating facilities owned by a tribal electric utility might meet the essential governmental function test, but there will be uncertainty until IRS makes a ruling, and there could be some distinctions drawn for generating equipment in which private investors have equity interests. This issue involves some uncharted territory. The IRS advance notice of proposed rulemaking indicates that facilities such as governmental office buildings and school buildings would qualify for bond financing, and so, presumably, energy efficiency measures and renewable energy features incorporated into such buildings should qualify.

The Energy Policy Act of 2005 created a variation on bond financing, a new mechanism known as "clean renewable energy bonds" (CREBs).[67] An investor who buys such a bond receives a tax credit. The issuer of such bonds uses the proceeds of the sale to finance investments in renewable energy projects, which ultimately generate enough revenue to pay off the bonds. The basic policy behind this kind of bond is to enable non-taxable entities – such as power companies owned by municipal governments – to attract private investment capital for renewable energy projects.

Indian tribes are included in the statutory definition of the term "governmental body," which is defined as "any State, territory, possession of the Untied States, the District of Columbia, Indian tribal government, and any political subdivision thereof."[68] The term "governmental body" is included in the statutory definition of two other key terms: "qualified issuer" and "qualified borrower." Accordingly, a tribe could be the issuer of clean renewable energy bonds, and a political subdivision of the tribe, such as a tribal electric utility, could be the borrower. The tribal utility would pay off the loan with revenue generated from its renewable energy projects, and the tribe would use that

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[65] Codified at 24 U.S.C. § 7871.

[66] 71 Fed. Reg. 45474 (Aug. 9, 2006).

[67] Pub. L. No. 109-58, § 1303 of the Act (adding a new section 54 to the Internal Revenue Code, 26 U.S.C. §54).

[68] *Id*.

revenue to pay off the investors who buy the bonds. A "qualified project" that may be financed through the issuance of such bonds is defined by reference to the section of the Internal Revenue Code that authorizes the investment tax credit for renewable energy facilities.[69] The kinds of projects that qualify include those that use wind energy, solar energy, biomass, landfill gas, and trash. In addition, certain kinds of "refined coal" facilities, hydropower projects, and small irrigation facilities qualify.

The 2005 Act authorized a total of $800,000,000 of tax credit bonds, provided that within this ceiling no more than $500 million could be allocated to governmental bodies. Under the Act this was a one time opportunity which has passed,[70] although it is possible that this mechanism could be revived in future legislation.

CONCLUSION

Over the next decade or so, the electric utility industry will continue to evolve, and some of the changes are likely to be rather sweeping. The changes will be away from fossil fuels and toward greater integration of distributed generation using renewable resources. These changes will be driven by a wide range of governmental policy tools as well as by technological developments. Given the federalist approach to utility regulation, some states and some regions are likely to see more sweeping changes sooner than others. One dramatic governmental policy tool that is hovering over this evolution is the possible enactment of national legislation to impose limits on carbon emissions, which would probably be accompanied by a system of trading credits for carbon offsets.

Although it has only been two years since the enactment of the Energy Policy Act of 2005,[71] a massive and somewhat disjointed act of Congress that was more than four years in the making, the current Congress is again considering energy legislation, driven largely by increased awareness of the need to deal with global warming. Perhaps legislation will be enacted before long that will begin to move us toward a post-fossil fuels economy. Whatever the mix of policy tools that eventually emerges, the grid is going to develop into a system with many different shapes and sizes of renewable energy systems and energy storage devices connected to it: wind turbines, photovoltaics, concentrating solar power, biomass cogeneration, fuel cells, and plug-in hybrid motor vehicles.

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[69] 26 U.S.C. §45.

[70] The Internal Revenue Service (IRS) issued Notice 2005-98 (December 12, 2005), setting out the requirements for applications for allocations of the $800 million ceiling. That notice is available on the IRS website at: www.irs,gov/pub/irs-drop/n-05-98.pdf. The deadline for applications for an allocation of the ceiling amount was April 26, 2006. The deadline for issuing the bonds is December 31, 2007. Money raised through bond sales must be spent for qualified projects within five years after the bonds are issued.

[71] Pub. L. No. 109-58.

Title V of the 2005 Act,[72] captioned “Indian Energy,” includes extensive provisions relating to energy development by tribal governments, including mandates for the Secretary of Interior and Secretary of Energy to establish assistance programs for tribes. Most of the provisions of the Indian Energy title replace statutory provisions enacted in the 1992 Energy Policy Act,[73] many of which were never implemented. Time will tell the extent to which the tribal provisions of the 2005 Act will actually be implemented. Advocacy by tribal governments and inter-tribal organizations may have some influence on decisions in DOI and DOE, and on appropriations by Congress.

One observation that has occurred to me in working with the Indian Energy title is that it is largely “stand-alone” legislation. There are numerous other places in the 2005 Act at which it would have been appropriate to include provisions relating to tribal governments, but, with some exceptions, tribes were generally left out. In legislation dealing with global warming, and reshaping the electric power industry in the process, I think that we should be talking about where tribes fit.

In light of the range of benefits that could be realized through the widespread adoption of energy efficiency measures and renewable energy technologies, the prominent role of electricity as the form of energy in which renewables are being brought to market, and the dramatic evolution within the electric utility industry, we need some serious attention to issues regarding how tribes as governments fit into the picture. Perhaps there should be a federally-created commission comprised of people with relevant expertise, including federal Indian law, renewable energy development, and traditional electric utilities. Such a commission would require commitments and follow through.[74] But a commission is just one idea. However it takes place, I believe that we need some attention to the subject. With the intent of contributing to some discussion of the subject matter, this article has raised some of the issues.

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[72] Indian Tribal Energy Development and Self-Determination Act of 2005, Pub. L. No. 109-58, title V.

[73] Pub. L. No. 102-486, title XXVI, § 2605 (formerly codified at 25 U.S.C. § 3505). Section 503 of the 2005 Act amends Title XXVI of the 1992 Energy Policy by replacing statutory language previously codified at 25 U.S.C. §§ 3501 – 3506 with new statutory text. *See* Suagee, *supra* note 50.

[74] The Energy Policy Act of 1992 had a mandate to establish an Indian Energy Resource Commission which was to have looked into such issues as dual taxation by tribes and states of reservation mineral resources. Pub. L. No. 102-486, title XXVI, § 2605 (formerly codified at 25 U.S.C. § 3505). That mandate was never carried out and was repealed by the Energy Policy Act of 2005. Pub. L. No. 109-58, title V.

COMMON DATA PEACH SPRINGS

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	Customer		January	February	March	April	May	June	July	August	September	October	November	December	Total
2			<<======	WINTER SEASON	======>>	<<======		SUMMER SEASON			======>>	<<======	WINTER SEASON	======>>	
3			744	672	744	720	744	720	744	744	720	744	720	744	8760
4	Hualapai Peach Springs Area														
5	R - 101														
6	Base Year Jan - Jun 2006 & July - Dec 2005	Number of Customers	365	360	360	359	357	359	360	365	368	360	362	364	362
7		kWh	280,767	270,434	284,129	235,923	225,107	150,963	224,159	190,988	197,181	186,344	264,658	308,466	2,819,119
8		KW [1]	943	1,006	955	819	756	524	753	642	685	626	919	1,037	1,037
9		Load Factor	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	31.0%
10		Retail Charge Excluding Taxes and Purchase Power Cost Adjustment	$ 26,825	$ 25,917	$ 27,057	$ 23,037	$ 22,118	$ 15,969	$ 22,068	$ 19,356	$ 19,899	$ 18,922	$ 25,456	$ 29,119	$ 275,743
11		Average $/kWh	0.0955	0.0958	0.0952	0.0976	0.0983	0.1058	0.0984	0.1013	0.1009	0.1015	0.0962	0.0944	0.0978
12	Forecasted Load														
13	2007	Escalation Rate - %	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
14		# of Customers	369	364	364	363	361	363	364	369	372	364	366	368	366
15		Total kWh	283,575	273,138	286,970	238,282	227,358	152,473	226,401	192,898	199,153	188,207	267,305	311,551	2,847,310
16		kW	953	1,016	964	827	764	529	761	648	692	632	928	1,047	1,047
17		Total Due	$ 27,093	$ 26,177	$ 27,327	$ 23,267	$ 22,339	$ 16,129	$ 22,288	$ 19,549	$ 20,098	$ 19,111	$ 25,710	$ 29,410	$ 278,500
18		Average $/kWh	0.0955	0.0958	0.0952	0.0976	0.0983	0.1058	0.0984	0.1013	0.1009	0.1015	0.0962	0.0944	0.0978
19	2008	Escalation Rate - %	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
20		# of Customers	373	368	368	367	365	367	368	373	376	368	370	372	369
21		Total kWh	286,410	275,870	289,840	240,665	229,632	153,997	228,665	194,827	201,144	190,090	269,978	314,666	2,875,783
22		kW	962	1,026	974	836	772	535	768	655	698	639	937	1,057	1,057
23		Total Due	$ 27,364	$ 26,438	$ 27,601	$ 23,500	$ 22,563	$ 16,290	$ 22,511	$ 19,745	$ 20,299	$ 19,302	$ 25,968	$ 29,705	$ 281,285
24		Average $/kWh	0.0955	0.0958	0.0952	0.0976	0.0983	0.1058	0.0984	0.1013	0.1009	0.1015	0.0962	0.0944	0.0978
25	2009	Escalation Rate - %	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
26		# of Customers	376	371	371	370	368	370	371	376	379	371	373	375	373
27		Total kWh	289,275	278,628	292,738	243,072	231,928	155,537	230,951	196,775	203,156	191,990	272,677	317,813	2,904,541
28		kW	972	1,037	984	844	779	540	776	661	705	645	947	1,068	1,068
29		Total Due	$ 27,637	$ 26,703	$ 27,877	$ 23,735	$ 22,788	$ 16,453	$ 22,736	$ 19,942	$ 20,502	$ 19,495	$ 26,227	$ 30,002	$ 284,098
30		Average $/kWh	0.0955	0.0958	0.0952	0.0976	0.0983	0.1058	0.0984	0.1013	0.1009	0.1015	0.0962	0.0944	0.0978
31	2010	Escalation Rate - %	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
32		# of Customers	380	375	375	374	372	374	375	380	383	375	377	379	377
33		Total kWh	292,167	281,415	295,666	245,502	234,247	157,093	233,261	198,743	205,187	193,910	275,404	320,991	2,933,587
34		kW	982	1,047	994	852	787	545	784	668	712	652	956	1,079	1,079
35		Total Due	$ 27,914	$ 26,970	$ 28,155	$ 23,972	$ 23,016	$ 16,618	$ 22,964	$ 20,142	$ 20,707	$ 19,690	$ 26,490	$ 30,302	$ 286,939
36		Average $/kWh	0.0955	0.0958	0.0952	0.0976	0.0983	0.1058	0.0984	0.1013	0.1009	0.1015	0.0962	0.0944	0.0978
37	2011	Escalation Rate - %	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
38		# of Customers	384	379	379	378	376	378	379	384	387	379	381	383	380
39		Total kWh	295,089	284,229	298,622	247,957	236,590	158,664	235,593	200,730	207,239	195,849	278,158	324,201	2,962,922
40		kW	992	1,057	1,003	861	795	551	792	674	720	658	966	1,089	1,089
41		Total Due	$ 28,193	$ 27,239	$ 28,437	$ 24,212	$ 23,246	$ 16,784	$ 23,193	$ 20,343	$ 20,915	$ 19,887	$ 26,754	$ 30,605	$ 289,809
42		Average $/kWh	0.0955	0.0958	0.0952	0.0976	0.0983	0.1058	0.0984	0.1013	0.1009	0.1015	0.0962	0.0944	0.0978
43	SCS-D - 503														
44	Base Year Jan - Jun 2006 & July - Dec 2005	Number of Customers	13	14	13	13	13	13	13	13	13	13	13	13	
45		kWh	96,932	113,758	100,080	86,220	84,200	114,360	117,646	94,272	105,867	78,790	87,253	95,945	1,175,323
46		KW [1]	580	580	515	500	496	442	482	506	466	404	433	439	580
47		Load Factor	22.5%	29.2%	26.1%	23.9%	22.8%	35.9%	32.8%	25.0%	31.6%	26.2%	28.0%	29.4%	
48		Retail Charge Excludin	$ 9,997	$ 10,901	$ 9,634	$ 8,763	$ 8,619	$ 9,796	$ 10,303	$ 9,243	$ 9,536	$ 7,569	$ 8,266	$ 8,782	$ 111,408
49		Average $/kWh	0.1031	0.0958	0.0963	0.1016	0.1024	0.0857	0.0876	0.0980	0.0901	0.0961	0.0947	0.0915	0.0948
50	Forecasted Load														
51	2007	Escalation Rate - %	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
52		# of Customers	13	14	13	13	13	13	13	13	13	13	13	13	13
53		Total kWh	97,901	114,896	101,081	87,082	85,042	115,504	118,822	95,215	106,926	79,578	88,126	96,904	1,187,076
54		kW	586	586	521	505	501	447	487	511	471	408	438	443	586
55		Total Due	$ 10,097	$ 11,010	$ 9,730	$ 8,851	$ 8,705	$ 9,894	$ 10,406	$ 9,336	$ 9,631	$ 7,645	$ 8,349	$ 8,870	$ 112,522
56		Average $/kWh	0.1031	0.0958	0.0963	0.1016	0.1024	0.0857	0.0876	0.0980	0.0901	0.0961	0.0947	0.0915	0.0948
57	2008	Escalation Rate - %	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
58		# of Customers	13	14	13	13	13	13	13	13	13	13	13	13	13
59		Total kWh	98,880	116,045	102,092	87,953	85,892	116,659	120,011	96,167	107,995	80,374	89,007	97,873	1,198,947
60		kW	592	592	526	510	506	451	492	516	475	412	442	448	592
61		Total Due	$ 10,197	$ 11,120	$ 9,827	$ 8,940	$ 8,792	$ 9,993	$ 10,510	$ 9,429	$ 9,728	$ 7,721	$ 8,432	$ 8,958	$ 113,647
62		Average $/kWh	0.1031	0.0958	0.0963	0.1016	0.1024	0.0857	0.0876	0.0980	0.0901	0.0961	0.0947	0.0915	0.0948
63	2009	Escalation Rate - %	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
64		# of Customers	13	14	13	13	13	13	13	13	13	13	13	13	13
65		Total kWh	99,869	117,205	103,113	88,833	86,751	117,825	121,211	97,129	109,075	81,177	89,897	98,852	1,210,936
66		kW	597	597	531	515	511	455	497	521	480	416	446	452	597
67		Total Due	$ 10,299	$ 11,231	$ 9,926	$ 9,029	$ 8,880	$ 10,093	$ 10,615	$ 9,523	$ 9,825	$ 7,798	$ 8,516	$ 9,048	$ 114,784
68		Average $/kWh	0.1031	0.0958	0.0963	0.1016	0.1024	0.0857	0.0876	0.0980	0.0901	0.0961	0.0947	0.0915	0.0948
69	2010	Escalation Rate - %	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
70		# of Customers	13	14	13	13	13	13	13	13	13	13	13	13	13
71		Total kWh	100,868	118,377	104,144	89,721	87,619	119,003	122,423	98,100	110,166	81,989	90,796	99,841	1,223,046
72		kW	603	603	536	521	516	460	502	526	485	420	451	457	603
73		Total Due	$ 10,402	$ 11,344	$ 10,025	$ 9,119	$ 8,968	$ 10,194	$ 10,721	$ 9,618	$ 9,923	$ 7,876	$ 8,602	$ 9,138	$ 115,932
74		Average $/kWh	0.1031	0.0958	0.0963	0.1016	0.1024	0.0857	0.0876	0.0980	0.0901	0.0961	0.0947	0.0915	0.0948
75	2011	Escalation Rate - %	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
76		# of Customers	14	15	14	14	14	14	14	14	14	14	14	14	14

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	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	Customer		January	February	March	April	May	June	July	August	September	October	November	December	Total
2			<<——— WINTER SEASON ———>>			<<——— SUMMER SEASON ———>>						<<——— WINTER SEASON ———>>			
77		Total kWh	101,877	119,561	105,185	90,618	88,495	120,194	123,647	99,081	111,267	82,809	91,704	100,839	1,235,276
78		kW	609	609	542	526	521	465	507	532	490	424	455	461	609
79		Total Due	$ 10,506	$ 11,457	$ 10,125	$ 9,210	$ 9,058	$ 10,296	$ 10,829	$ 9,715	$ 10,022	$ 7,955	$ 8,688	$ 9,230	$ 117,091
80		Average $/kWh	0.1031	0.0958	0.0963	0.1016	0.1024	0.0857	0.0876	0.0980	0.0901	0.0961	0.0947	0.0915	0.0948
81															
82	SCS-E - 504														
83	Base Year Jan - Jun 2006 & July - Dec 2005	Number of Customers	57	55	59	58	57	59	55	55	50	56	56	56	
84		kWh	77,199	77,172	75,414	66,150	65,648	69,318	72,107	57,301	59,950	52,423	56,930	71,172	800,784
85		KW [1]	245	277	259	254	252	266	244	200	203	208	207	239	277
86		Load Factor	42.4%	41.5%	39.1%	36.1%	35.0%	36.2%	39.8%	38.5%	41.1%	33.8%	38.3%	40.0%	
87		Retail Charge Excludin	$ 6,983	$ 6,957	$ 6,862	$ 6,094	$ 6,041	$ 6,364	$ 6,544	$ 5,336	$ 5,492	$ 4,950	$ 5,317	$ 6,480	$ 73,420
88		Average $/kWh	0.0905	0.0902	0.0910	0.0921	0.0920	0.0918	0.0908	0.0931	0.0916	0.0944	0.0934	0.0910	0.0917
89															
90	Justice Bldg - July 07 ISD	# of Customers	1.0000	1	1	1	1	1	1	1	1	1	1	1	
91		kW	88	100	94	92	91	96	88	72	73	75	75	86	100
92		kWh	27,887	27,877	27,242	23,896	23,714	25,040	26,048	20,699	21,656	18,937	20,565	25,710	289,273
93		Percent of Peak	0.8838	1.0000	0.9357	0.9191	0.9112	0.9603	0.8803	0.7225	0.7319	0.7522	0.7460	0.8632	
94		Retail Charge Excludin	$ 2,523	$ 2,513	$ 2,479	$ 2,201	$ 2,182	$ 2,299	$ 2,364	$ 1,927	$ 1,984	$ 1,788	$ 1,921	$ 2,341	26,522.0135
95															
96	Forecasted Load														
97	2007	Escalation Rate - %	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
98		# of Customers	58	56	60	59	58	60	57	57	52	58	58	58	58
99		Total kWh	77,971	77,944	76,168	66,812	66,304	70,011	98,876	78,573	82,206	71,884	78,065	97,594	942,407
100		kW	247	280	262	257	255	269	334	274	278	286	283	328	334
101		Total Due	$ 7,053	$ 7,027	$ 6,930	$ 6,155	$ 6,101	$ 6,428	$ 8,973	$ 7,317	$ 7,531	$ 6,787	$ 7,292	$ 8,885	$ 86,479
102		Average $/kWh	0.0905	0.0902	0.0910	0.0921	0.0920	0.0918	0.0908	0.0931	0.0916	0.0944	0.0934	0.0910	0.0918
103	2008	Escalation Rate - %	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
104		# of Customers	60	58	62	61	60	62	58	58	53	59	59	59	59
105		Total kWh	106,638	106,601	104,172	91,375	90,682	95,752	99,865	79,359	83,028	72,603	78,845	98,570	1,107,489
106		kW	497	562	526	517	512	540	337	277	281	288	286	331	562
107		Total Due	$ 9,646	$ 9,610	$ 9,478	$ 8,418	$ 8,344	$ 8,791	$ 9,063	$ 7,390	$ 7,606	$ 6,855	$ 7,364	$ 8,974	$ 101,541
108		Average $/kWh	0.0905	0.0902	0.0910	0.0921	0.0920	0.0918	0.0908	0.0931	0.0916	0.0944	0.0934	0.0910	0.0917
109	2009	Escalation Rate - %	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
110		# of Customers	60	58	62	61	60	62	58	58	53	59	59	59	59
111		Total kWh	107,704	107,667	105,214	92,289	91,589	96,709	100,863	80,153	83,858	73,329	79,634	99,555	1,118,564
112		kW	502	568	531	522	517	545	341	280	283	291	289	334	568
113		Total Due	$ 9,743	$ 9,706	$ 9,573	$ 8,502	$ 8,428	$ 8,879	$ 9,154	$ 7,464	$ 7,682	$ 6,924	$ 7,438	$ 9,064	$ 102,556
114		Average $/kWh	0.0905	0.0902	0.0910	0.0921	0.0920	0.0918	0.0908	0.0931	0.0916	0.0944	0.0934	0.0910	0.0917
115	2010	Escalation Rate - %	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
116		# of Customers	61	59	63	62	61	63	59	59	54	60	60	60	60
117		Total kWh	108,781	108,743	106,266	93,212	92,505	97,676	101,872	80,954	84,697	74,063	80,430	100,551	1,129,749
118		kW	507	573	536	527	522	551	344	283	286	294	292	338	573
119		Total Due	$ 9,840	$ 9,803	$ 9,669	$ 8,587	$ 8,512	$ 8,968	$ 9,245	$ 7,538	$ 7,759	$ 6,993	$ 7,512	$ 9,154	$ 103,582
120		Average $/kWh	0.0905	0.0902	0.0910	0.0921	0.0920	0.0918	0.0908	0.0931	0.0916	0.0944	0.0934	0.0910	0.0917
121	2011	Escalation Rate - %	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
122		# of Customers	61	59	63	62	61	63	59	59	54	60	60	60	60
123		Total kWh	109,869	109,831	107,329	94,144	93,430	98,653	102,891	81,764	85,544	74,803	81,234	101,556	1,141,047
124		kW	512	579	542	532	528	556	348	285	289	297	295	341	579
125		Total Due	$ 9,939	$ 9,901	$ 9,766	$ 8,673	$ 8,597	$ 9,058	$ 9,338	$ 7,614	$ 7,837	$ 7,063	$ 7,588	$ 9,246	$ 104,618
126		Average $/kWh	0.0905	0.0902	0.0910	0.0921	0.0920	0.0918	0.0908	0.0931	0.0916	0.0944	0.0934	0.0910	0.0917
127															
128	L - 605														
129	Base Year Jan - Jun 2006 & July - Dec 2005	Number of Customers	2	2	2	2	2	2	2	2	2	2	2	2	
130		kWh	62,560	58,480	68,960	67,040	74,240	92,560	127,040	100,880	110,080	79,600	73,600	62,000	977,040
131		KW [1]	193	187	228	205	233	234	278	266	242	204	181	172	278
132		Load Factor	43.6%	46.5%	40.7%	45.5%	42.9%	55.0%	61.5%	51.1%	63.3%	52.4%	56.5%	48.4%	
133		Retail Charge Excludin	$ 4,813	$ 4,572	$ 5,448	$ 5,134	$ 5,735	$ 6,578	$ 8,579	$ 7,269	$ 7,455	$ 5,699	$ 5,199	$ 4,584	$ 71,064
134		Average $/kWh	0.0769	0.0782	0.0790	0.0766	0.0773	0.0711	0.0675	0.0721	0.0677	0.0716	0.0706	0.0739	0.0727
135	Forecasted Load														
136	2007	Escalation Rate - %	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
137		# of Customers	2	2	2	2	2	2	2	2	2	2	2	2	2
138		Total kWh	63,186	59,065	69,650	67,710	74,982	93,486	128,310	101,889	111,181	80,396	74,336	62,620	986,810
139		kW	195	189	230	207	235	236	280	268	244	206	183	174	280
140		Total Due	$ 4,861	$ 4,618	$ 5,502	$ 5,185	$ 5,793	$ 6,644	$ 8,664	$ 7,342	$ 7,529	$ 5,756	$ 5,251	$ 4,630	$ 71,775
141		Average $/kWh	0.0769	0.0782	0.0790	0.0766	0.0773	0.0711	0.0675	0.0721	0.0677	0.0716	0.0706	0.0739	0.0727
142	2008	Escalation Rate - %	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
143		# of Customers	2	2	2	2	2	2	2	2	2	2	2	2	2
144		Total kWh	63,817	59,655	70,346	68,388	75,732	94,420	129,594	102,908	112,293	81,200	75,079	63,246	996,679
145		kW	197	191	233	209	237	238	283	271	246	208	184	175	283
146		Total Due	$ 4,910	$ 4,664	$ 5,557	$ 5,237	$ 5,850	$ 6,710	$ 8,751	$ 7,415	$ 7,604	$ 5,813	$ 5,303	$ 4,677	$ 72,493
147		Average $/kWh	0.0769	0.0782	0.0790	0.0766	0.0773	0.0711	0.0675	0.0721	0.0677	0.0716	0.0706	0.0739	0.0727
148	2009	Escalation Rate - %	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
149		# of Customers	2	2	2	2	2	2	2	2	2	2	2	2	2
150		Total kWh	64,456	60,252	71,050	69,071	76,490	95,365	130,889	103,937	113,416	82,012	75,830	63,879	1,006,645
151		kW	199	193	235	211	240	241	286	274	249	210	186	177	286
152		Total Due	$ 4,959	$ 4,711	$ 5,613	$ 5,290	$ 5,909	$ 6,777	$ 8,839	$ 7,489	$ 7,680	$ 5,871	$ 5,357	$ 4,723	$ 73,218
153		Average $/kWh	0.0769	0.0782	0.0790	0.0766	0.0773	0.0711	0.0675	0.0721	0.0677	0.0716	0.0706	0.0739	0.0727

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	Customer		January	February	March	April	May	June	July	August	September	October	November	December	Total
2			<<——— WINTER SEASON ———>>			<<——— SUMMER SEASON ———>>						<<——— WINTER SEASON ———>>			
154	2010	Escalation Rate - %	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
155		# of Customers	2	2	2	2	2	2	2	2	2	2	2	2	2
156		Total kWh	65,100	60,855	71,760	69,762	77,254	96,318	132,198	104,976	114,550	82,832	76,588	64,517	1,016,712
157		kW	201	195	237	213	242	243	289	276	251	212	188	179	289
158		Total Due	$ 5,008	$ 4,758	$ 5,669	$ 5,342	$ 5,968	$ 6,845	$ 8,927	$ 7,564	$ 7,757	$ 5,930	$ 5,410	$ 4,771	$ 73,950
159		Average $/kWh	0.0769	0.0782	0.0790	0.0766	0.0773	0.0711	0.0675	0.0721	0.0677	0.0716	0.0706	0.0739	0.0727
160	2011	Escalation Rate - %	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	
161		# of Customers	2	2	2	2	2	2	2	2	2	2	2	2	2
162		Total kWh	65,751	61,463	72,478	70,460	78,027	97,281	133,520	106,026	115,695	83,660	77,354	65,163	1,026,879
163		kW	203	197	240	215	245	246	292	279	254	214	190	181	292
164		Total Due	$ 5,058	$ 4,805	$ 5,726	$ 5,396	$ 6,028	$ 6,914	$ 9,016	$ 7,640	$ 7,835	$ 5,989	$ 5,464	$ 4,818	$ 74,689
165		Average $/kWh	0.0769	0.0782	0.0790	0.0766	0.0773	0.0711	0.0675	0.0721	0.0677	0.0716	0.0706	0.0739	0.0727
166															
167	Hualapai Peach Springs Area														
168	Summary At Meter														
169	Base Year Jan - Jun 2006 & July - Dec 2005	# of Customers	437	431	434	432	429	433	430	435	433	431	433	435	433
170		Total kW h	517,458	519,844	528,583	455,333	449,195	427,201	540,952	443,441	473,078	397,157	482,441	537,583	5,772,266
171		kW	1,961	2,050	1,957	1,779	1,737	1,466	1,757	1,613	1,595	1,442	1,739	1,887	2,050
172		Total Due	$ 48,617	$ 48,348	$ 49,000	$ 43,028	$ 42,513	$ 38,708	$ 47,493	$ 41,204	$ 42,382	$ 37,139	$ 44,238	$ 48,965	$ 531,635
173	Forecasted Load														
174	2007	# of Customers	442	436	439	437	434	438	436	441	439	437	439	441	438
175		Total kWh	522,633	525,042	533,869	459,886	453,687	431,473	572,409	468,575	499,465	420,066	507,831	568,669	5,963,604
176		kW	1,980	2,071	1,977	1,796	1,755	1,480	1,862	1,702	1,684	1,532	1,831	1,992	2,071
177		Total Due	$ 49,103	$ 48,831	$ 49,490	$ 43,458	$ 42,938	$ 39,095	$ 50,332	$ 43,543	$ 44,790	$ 39,299	$ 46,602	$ 51,796	$ 549,277
178	2008	# of Customers	447	441	444	442	439	443	440	445	443	441	443	445	443
179		Total kWh	555,746	558,170	566,450	488,381	481,938	460,828	578,133	473,260	504,460	424,266	512,909	574,355	6,178,898
180		kW	2,247	2,371	2,258	2,071	2,027	1,764	1,881	1,719	1,701	1,547	1,850	2,012	2,371
181		Total Due	$ 52,117	$ 51,833	$ 52,463	$ 46,094	$ 45,549	$ 41,785	$ 50,835	$ 43,979	$ 45,237	$ 39,692	$ 47,068	$ 52,314	$ 568,966
182	2009	# of Customers	452	446	449	447	444	448	445	450	448	446	448	450	448
183		Total kWh	561,304	563,752	572,114	493,265	486,758	465,436	583,915	477,993	509,504	428,509	518,038	580,099	6,240,687
184		kW	2,270	2,395	2,281	2,092	2,047	1,781	1,900	1,736	1,718	1,563	1,868	2,032	2,395
185		Total Due	$ 52,638	$ 52,351	$ 52,988	$ 46,555	$ 46,005	$ 42,202	$ 51,344	$ 44,419	$ 45,690	$ 40,089	$ 47,538	$ 52,837	$ 574,656
186	2010	# of Customers	456	450	453	451	448	452	449	454	452	450	452	454	452
187		Total kWh	566,917	569,389	577,835	498,197	491,625	470,091	589,754	482,773	514,599	432,794	523,218	585,900	6,303,093
188		kW	2,292	2,418	2,303	2,113	2,068	1,799	1,919	1,753	1,735	1,578	1,887	2,052	2,418
189		Total Due	$ 53,165	$ 52,875	$ 53,518	$ 47,021	$ 46,465	$ 42,624	$ 51,857	$ 44,863	$ 46,147	$ 40,490	$ 48,014	$ 53,365	$ 580,403
190	2011	# of Customers	461	455	458	456	453	457	454	459	457	455	457	459	457
191		Total kWh	572,586	575,083	583,614	503,179	496,542	474,792	595,651	487,601	519,745	437,122	528,451	591,759	6,366,124
192		kW	2,315	2,443	2,327	2,134	2,088	1,817	1,938	1,771	1,752	1,594	1,906	2,073	2,443
193		Total Due	$ 53,696	$ 53,403	$ 54,053	$ 47,491	$ 46,930	$ 43,051	$ 52,376	$ 45,311	$ 46,608	$ 40,895	$ 48,494	$ 53,899	$ 586,207
194															
195															
196															
197	**Annual Average Cost of Energy**			2,007	2008	2009	2010	2011							
198	**MEC 2006 Effective Rates**			(47,492)	$ (79,917)	$ (104,677)	$ (129,680)	$ (155,043)							
199	**cents / kWh**														
200	**Customer Type**	**cents / kWh**													
201	Residential	9.7812													
202	Small Commercial with Demand	9.4789													
203	Small Commercial with Energy	9.1685													
204	Large Commercial	7.2734													
205	Peach Springs Area Combined	9.2102													
206															

BASE CASE - OM&C

	A	B	C	D	E
14	OM&C	0	1	2	3
15	O&M	0.0%	$ 1.00	$/kW per 16 Month High kW	
16	Maintenance Premiums	0.0%	$ -	times the number of hours	
17	Materials	0.0%	$ 1,667		
18		0.0%	$ -		
19	Customer Service / Call Center	0.0%	$ -		
20	Meter Reading:	0.0%	$ 2.00	Per customer	
21	Training Services:	0.0%	$ -		
22	Billing	0.0%	$ -	Part of Meter Reading Fee	

BASE CASE PEACH SPRINGS

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						RESOURCES VERSUS LOADS								
3		January	February	March	April	May	June	July	August	September	October	November	December	Total
4	CRSP Season	<<——— WINTER SEASON ———>>			<<——— SUMMER SEASON ———>>						<<——— WINTER SEASON ———>>			
5	Supplemental Season	<<——— WINTER SEASON ———>>				<<——— SUMMER SEASON ———>>						<<—— WINTER SEASON ——>>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
7	2007													
8	RESOURCES													
9	At CRSP Delivery													
10	CRSP Available Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
11	CRSP Available Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
12	Max WRP kWh	212,635	192,058	212,635	227,522	235,106	227,522	235,106	235,106	227,522	212,635	205,776	212,635	2,636,262
13	Max CRSP Aggregate kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
14	Renewable Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Renewable Scheduled Capacity - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Supplemental Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Supplemental Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Total Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
19	Total Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
20	At Meter													
21	CRSP AvailableCapacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
22	CRSP & WRP Available Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097
23	Renewable Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
24	Renewable Scheduled Capacity - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
25	Supplemental Capacity - kW	1,442	1,532	1,438	1,243	1,202	927	1,309	1,149	1,131	993	1,293	1,453	1,532
26	Supplemental Energy - kWh	121,762	162,966	132,998	61,755	42,285	33,342	161,007	57,172	101,334	19,195	119,892	167,798	1,181,507
27	Total Capacity - kW	1,980	2,071	1,977	1,796	1,755	1,480	1,862	1,702	1,684	1,532	1,831	1,992	2,071
28	Total Energy -kWh	522,633	525,042	533,869	459,886	453,687	431,473	572,409	468,575	499,465	420,066	507,831	568,669	5,963,604
29														
30	Load At Meter													
31	Demand													
32	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
33	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
34	Hualapai Peach Springs Area	1,980	2,071	1,977	1,796	1,755	1,480	1,862	1,702	1,684	1,532	1,831	1,992	
35	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
36	Demand Subtotal	1,980	2,071	1,977	1,796	1,755	1,480	1,862	1,702	1,684	1,532	1,831	1,992	2,071
37	Energy													
38	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
39	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
40	Hualapai Peach Springs Area	522,633	525,042	533,869	459,886	453,687	431,473	572,409	468,575	499,465	420,066	507,831	568,669	
41	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
42	Energy Subtotal	522,633	525,042	533,869	459,886	453,687	431,473	572,409	468,575	499,465	420,066	507,831	568,669	5,963,604
43														
44	Resource Vs. Load At Meter													
45	Capacity Excess/(Deficiency) (1)	-	-	-	-	-	-	-	-	-	-	-	-	-
46	Energy Excess/(Deficiency) (2)	-	-	-	-	-	-	-	-	-	-	-	-	-
47														
48	2008													
49	RESOURCES													
50	At CRSP Delivery													
51	CRSP Available Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
52	CRSP Available Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
53	WRP kWh	212,635	192,058	212,635	227,522	235,106	227,522	235,106	235,106	227,522	212,635	205,776	212,635	2,636,262
54	Aggregate kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
55	Renewable Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
56	Renewable Scheduled Capacity - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
57	Supplemental Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
58	Supplemental Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
59	Total Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
60	Total Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
61	At Meter													
62	CRSP AvailableCapacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
63	CRSP & WRP Available Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097
64	Renewable Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
65	Renewable Scheduled Capacity - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
66	Supplemental Capacity - kW	1,708	1,832	1,719	1,518	1,474	1,211	1,328	1,166	1,148	1,008	1,311	1,473	1,832

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						RESOURCES VERSUS LOADS								
3		January	February	March	April	May	June	July	August	September	October	November	December	Total
4	CRSP Season	<<——— WINTER SEASON ———>>			<<——— SUMMER SEASON ———>>						<<——— WINTER SEASON ———>>			
5	Supplemental Season	<<——— WINTER SEASON ———>>				<<——— SUMMER SEASON ———>>						<<—— WINTER SEASON ——>>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
67	Supplemental Energy - kWh	154,876	196,094	165,580	90,250	70,536	62,697	166,731	61,858	106,328	23,396	124,970	173,485	1,396,800
68	Total Capacity - kW	2,247	2,371	2,258	2,071	2,027	1,764	1,881	1,719	1,701	1,547	1,850	2,012	2,371
69	Total Energy -kWh	555,746	558,170	566,450	488,381	481,938	460,828	578,133	473,260	504,460	424,266	512,909	574,355	6,178,898
70														
71	Load At Meter													
72	Demand													
73	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
74	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
75	Hualapai Peach Springs Area	2,247	2,371	2,258	2,071	2,027	1,764	1,881	1,719	1,701	1,547	1,850	2,012	
76	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
77	Demand Subtotal	2,247	2,371	2,258	2,071	2,027	1,764	1,881	1,719	1,701	1,547	1,850	2,012	2,371
78	Energy													
79	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
80	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
81	Hualapai Peach Springs Area	555,746	558,170	566,450	488,381	481,938	460,828	578,133	473,260	504,460	424,266	512,909	574,355	
82	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
83	Energy Subtotal	555,746	558,170	566,450	488,381	481,938	460,828	578,133	473,260	504,460	424,266	512,909	574,355	6,178,898
84														
85	Resource Vs. Load At Meter													
86	Capacity Excess/(Deficiency) {1}	-	-	-	-	-	-	-	-	-	-	-	-	-
87	Energy Excess/(Deficiency) {2}	-	-	-	-	-	-	-	-	-	-	-	-	-
88														
89	2009													
90	RESOURCES													
91	At CRSP Delivery													
92	CRSP Available Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
93	CRSP Available Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
94	WRP kWh	212,635	192,058	212,635	227,522	235,106	227,522	235,106	235,106	227,522	212,635	205,776	212,635	2,636,262
95	Aggregate kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
96	Renewable Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
97	Renewable Scheduled Capacity - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
98	Supplemental Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
99	Supplemental Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
100	Total Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
101	Total Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
102	At Meter													
103	CRSP AvailableCapacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
104	CRSP & WRP Available Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097
105	Renewable Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
106	Renewable Scheduled Capacity - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
107	Supplemental Capacity - kW	1,731	1,856	1,742	1,539	1,494	1,228	1,347	1,183	1,165	1,024	1,329	1,493	0
108	Supplemental Energy - kWh	160,433	201,676	171,244	95,134	75,355	67,305	172,512	66,591	111,373	27,639	130,099	179,229	0
109	Total Capacity - kW	2,270	2,395	2,281	2,092	2,047	1,781	1,900	1,736	1,718	1,563	1,868	2,032	2,395
110	Total Energy -kWh	561,304	563,752	572,114	493,265	486,758	465,436	583,915	477,993	509,504	428,509	518,038	580,099	6,240,687
111														
112	Load At Meter													
113	Demand													
114	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
115	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
116	Hualapai Peach Springs Area	2,270	2,395	2,281	2,092	2,047	1,781	1,900	1,736	1,718	1,563	1,868	2,032	
117	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
118	Demand Subtotal	2,270	2,395	2,281	2,092	2,047	1,781	1,900	1,736	1,718	1,563	1,868	2,032	2,395
119	Energy													
120	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
121	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
122	Hualapai Peach Springs Area	561,304	563,752	572,114	493,265	486,758	465,436	583,915	477,993	509,504	428,509	518,038	580,099	
123	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
124	Energy Subtotal	561,304	563,752	572,114	493,265	486,758	465,436	583,915	477,993	509,504	428,509	518,038	580,099	6,240,687
125														
126	Resource Vs. Load At Meter													

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						RESOURCES VERSUS LOADS								
3		January	February	March	April	May	June	July	August	September	October	November	December	Total
4	CRSP Season		<<—— WINTER SEASON ——>>				<<—— SUMMER SEASON ——>>					<<—— WINTER SEASON ——>>		
5	Supplemental Season		<<—— WINTER SEASON ——>>					<<—— SUMMER SEASON ——>>				<<—— WINTER SEASON ——>>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
127	Capacity Excess/(Deficiency) {1}	-	-	-	-	-	-	-	-	-	-	-	-	-
128	Energy Excess/(Deficiency) {2}	-	-	-	-	-	-	-	-	-	-	-	-	-
129														
130	**2010**													
131	**RESOURCES**													
132	At CRSP Delivery													
133	CRSP Available Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
134	CRSP Available Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
135	WRP kWh	212,635	192,058	212,635	227,522	235,106	227,522	235,106	235,106	227,522	212,635	205,776	212,635	2,636,262
136	Aggregate kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
137	Renewable Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
138	Renewable Scheduled Capacity - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
139	Supplemental Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
140	Supplemental Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
141	Total Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
142	Total Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
143	At Meter													
144	CRSP AvailableCapacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
145	CRSP & WRP Available Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097
146	Renewable Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
147	Renewable Scheduled Capacity - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
148	Supplemental Capacity - kW	1,754	1,880	1,765	1,560	1,515	1,246	1,366	1,200	1,182	1,039	1,348	1,513	0
149	Supplemental Energy - kWh	166,046	207,313	176,965	100,066	80,223	71,959	178,352	71,371	116,468	31,924	135,279	185,030	0
150	Total Capacity - kW	2,292	2,418	2,303	2,113	2,068	1,799	1,919	1,753	1,735	1,578	1,887	2,052	2,418
151	Total Energy -kWh	566,917	569,389	577,835	498,197	491,625	470,091	589,754	482,773	514,599	432,794	523,218	585,900	6,303,093
152														
153	Load At Meter													
154	**Demand**													
155	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
156	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
157	Hualapai Peach Springs Area	2,292	2,418	2,303	2,113	2,068	1,799	1,919	1,753	1,735	1,578	1,887	2,052	
158	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
159	**Demand Subtotal**	**2,292**	**2,418**	**2,303**	**2,113**	**2,068**	**1,799**	**1,919**	**1,753**	**1,735**	**1,578**	**1,887**	**2,052**	2,418
160	**Energy**													
161	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
162	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
163	Hualapai Peach Springs Area	566,917	569,389	577,835	498,197	491,625	470,091	589,754	482,773	514,599	432,794	523,218	585,900	
164	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
165	**Energy Subtotal**	**566,917**	**569,389**	**577,835**	**498,197**	**491,625**	**470,091**	**589,754**	**482,773**	**514,599**	**432,794**	**523,218**	**585,900**	6,303,093
166														
167	**Resource Vs. Load At Meter**													
168	Capacity Excess/(Deficiency) {1}	-	-	-	-	-	-	-	-	-	-	-	-	-
169	Energy Excess/(Deficiency) {2}	-	-	-	-	-	-	-	-	-	-	-	-	-
170														
171	**2011**													
172	**RESOURCES**													
173	At CRSP Delivery													
174	CRSP Available Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
175	CRSP Available Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
176	WRP Available kWh	212,635	192,058	212,635	227,522	235,106	227,522	235,106	235,106	227,522	212,635	205,776	212,635	2,636,262
177	Aggregate kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
178	Renewable Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
179	Renewable Scheduled Capacity - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
180	Supplemental Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
181	Supplemental Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
182	Total Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
183	Total Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
184	At Meter													
185	CRSP AvailableCapacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
186	CRSP & WRP Available Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097

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	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						RESOURCES VERSUS LOADS								
3		January	February	March	April	May	June	July	August	September	October	November	December	Total
4	CRSP Season	<<—— WINTER SEASON ——>>			<<—— SUMMER SEASON ——>>						<<—— WINTER SEASON ——>>			
5	Supplemental Season	<<—— WINTER SEASON ——>>				<<—— SUMMER SEASON ——>>						<<—— WINTER SEASON ——>>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
187	Renewable Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
188	Renewable Scheduled Capacity - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
189	Supplemental Capacity - kW	1,777	1,904	1,788	1,581	1,535	1,264	1,385	1,218	1,199	1,055	1,367	1,534	0
190	Supplemental Energy - kWh	171,715	213,007	182,744	105,048	85,139	76,660	184,249	76,198	121,614	36,252	140,512	190,889	0
191	Total Capacity - kW	2,315	2,443	2,327	2,134	2,088	1,817	1,938	1,771	1,752	1,594	1,906	2,073	2,443
192	Total Energy -kWh	572,586	575,083	583,614	503,179	496,542	474,792	595,651	487,601	519,745	437,122	528,451	591,759	6,366,124
193														
194	Load At Meter													
195	**Demand**													
196	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
197	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
198	Hualapai Peach Springs Area	2,315	2,443	2,327	2,134	2,088	1,817	1,938	1,771	1,752	1,594	1,906	2,073	
199	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
200	**Demand Subtotal**	**2,315**	**2,443**	**2,327**	**2,134**	**2,088**	**1,817**	**1,938**	**1,771**	**1,752**	**1,594**	**1,906**	**2,073**	2,443
201	**Energy**													
202	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
203	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
204	Hualapai Peach Springs Area	572,586	575,083	583,614	503,179	496,542	474,792	595,651	487,601	519,745	437,122	528,451	591,759	
205	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
206	**Energy Subtotal**	**572,586**	**575,083**	**583,614**	**503,179**	**496,542**	**474,792**	**595,651**	**487,601**	**519,745**	**437,122**	**528,451**	**591,759**	6,366,124
207														
208	Resource Vs. Load At Meter													
209	Capacity Excess/(Deficiency) {1}	-	-	-	-	-	-	-	-	-	-	-	-	-
210	Energy Excess/(Deficiency) {2}	-	-	-	-	-	-	-	-	-	-	-	-	-
211														
212	{1} Resource Minus Load (i.e., if Resources greater than Loads there is excess;													
213	if Resources less than Loads there is a deficiency)													
214														
215	{2} Resource Minus Load (i.e., if Resources greater than Loads there is excess;													
216	if Resources less than Loads there is a deficiency)													

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	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	CRSP Allocation	S	W			Hualapai								
2	CROD	625	609			CRSP SLCIP RESOURCES								
3	Energy	1,357,114	1,411,736											
4		January	February	March	April	May	June	July	August	September	October	November	December	Total
5		<<	WINTER SEASON	>>	<<		SUMMER SEASON			>>	<<	WINTER SEASON	>>	
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
7	P Max Capacity At CRSP Delviery - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
8	**2007**													
9	**CRSP AT CRSP Delivery**													
10	Escalation Rate - %	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
11	Max Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
12	Scheduled Capacity	609	609	609	625	625	625	625	625	625	609	609	609	625
13	Capacity $/kW/Month	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12	
14	Scheduled Capacity Cost	$ 2,509.57	$ 2,509.57	$ 2,509.57	$ 2,575.50	$ 2,575.50	$ 2,575.50	$ 2,575.50	$ 2,575.50	$ 2,575.50	$ 2,509.57	$ 2,509.57	$ 2,509.57	$ 30,510.40
15	Parker-Davis Transmission Cost - $/kW	$ 1.10	$ 1.10	$ 1.10	$ 1.10	$ 1.10	$ 1.10	$ 1.10	$ 1.10	$ 1.10	$ 1.10	$ 1.10	$ 1.10	
16	Parker-Davis Transmission Cost - $	$ 670.87	$ 670.87	$ 670.87	$ 688.50	$ 688.50	$ 688.50	$ 688.50	$ 688.50	$ 688.50	$ 670.87	$ 670.87	$ 670.87	$ 8,156.25
17	Max Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
18	Scheduled Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
19	Energy $/kWh	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	
20	Scheduled Energy Cost	$ 2,330.06	$ 2,104.57	$ 2,330.06	$ 2,155.81	$ 2,227.67	$ 2,155.81	$ 2,227.67	$ 2,227.67	$ 2,155.81	$ 2,330.06	$ 2,254.90	$ 2,330.06	$ 26,830.16
21	Load Factor - %	53.1%	53.1%	53.1%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	53.1%	53.1%	53.1%	50.6%
22	Total CRSP Cost	$ 5,510.50	$ 5,285.01	$ 5,510.50	$ 5,419.81	$ 5,491.67	$ 5,419.81	$ 5,491.67	$ 5,491.67	$ 5,419.81	$ 5,510.50	$ 5,435.34	$ 5,510.50	$ 65,496.81
23	Average CRSP Cost - kWh	$ 22.92	$ 24.33	$ 22.92	$ 24.36	$ 23.89	$ 24.36	$ 23.89	$ 23.89	$ 24.36	$ 22.92	$ 23.36	$ 22.92	
24	WRP Energy - kWh	212,635	192,058	212,635	227,522	235,106	227,522	235,106	235,106	227,522	212,635	205,776	212,635	2,636,262
25	WRP - $/MWH	50	50	50	50	50	50	50	50	50	50	50	50	
26	WRP Cost	$ 10,631.77	$ 9,602.89	$ 10,631.77	$ 11,376.11	$ 11,755.32	$ 11,376.11	$ 11,755.32	$ 11,755.32	$ 11,376.11	$ 10,631.77	$ 10,288.81	$ 10,631.77	$ 131,813.10
27	Total CRSP Plus WRP Cost	$ 16,142.28	$ 14,887.91	$ 16,142.28	$ 16,795.92	$ 17,246.99	$ 16,795.92	$ 17,246.99	$ 17,246.99	$ 16,795.92	$ 16,142.28	$ 15,724.15	$ 16,142.28	$ 197,309.91
28	Total Max Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
29	Scheduled Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
30	Aggregate Scheduled Load Factor	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	98.7%
31	eduled Aggregate Average Cost $/MWH	$ 35.63	$ 36.38	$ 35.63	$ 37.32	$ 37.09	$ 37.32	$ 37.09	$ 37.09	$ 37.32	$ 35.63	$ 35.86	$ 35.63	$ 36.50
32														
33	**CRSP At Delivery**													
34	Max Capacity - kW	585	585	585	600	600	600	600	600	600	585	585	585	600
35	Max Energy - kWh	434,972	392,878	434,972	432,000	446,400	432,000	446,400	446,400	432,000	434,972	420,941	434,972	5,188,908
36	Scheduled Capacity - kW	585	585	585	600	600	600	600	600	600	585	585	585	
37	Scheduled Energy - kWh	434,972	392,878	434,972	432,000	446,400	432,000	446,400	446,400	432,000	434,972	420,941	434,972	
38	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
39														
40	**CRSP At Nelson**													
41	Max Capacity - kW	561	561	561	576	576	576	576	576	576	561	561	561	
42	Max Energy - kWh	417,573	377,163	417,573	414,720	428,544	414,720	428,544	428,544	414,720	417,573	404,103	417,573	
43	Scheduled Capacity - kW	561	561	561	576	576	576	576	576	576	561	561	561	
44	Scheduled Energy - kWh	417,573	377,163	417,573	414,720	428,544	414,720	428,544	428,544	414,720	417,573	404,103	417,573	
45	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
46														
47	**CRSP At Customer Meter**													
48	Max Capacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
49	Scheduled Capacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
50	Max Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097
51	Scheduled Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097
52	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
53	Scheduled Average Cost $/MWH	$ 40.27	$ 41.12	$ 40.27	$ 42.19	$ 41.92	$ 42.19	$ 41.92	$ 41.92	$ 42.19	$ 40.27	$ 40.53	$ 40.27	$ 41.26
54														
55	**2008**													
56	**CRSP AT CRSP Delivery**													
57	Escalation Rate - %	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
58	Max Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
59	Scheduled Capacity	609	609	609	625	625	625	625	625	625	609	609	609	625
60	Capacity $/kW/Month	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	
61	Scheduled Capacity Cost	$ 2,559.76	$ 2,559.76	$ 2,559.76	$ 2,627.01	$ 2,627.01	$ 2,627.01	$ 2,627.01	$ 2,627.01	$ 2,627.01	$ 2,559.76	$ 2,559.76	$ 2,559.76	$ 31,120.61
62	Parker-Davis Transmission Cost - $/kW	$ 1.12	$ 1.12	$ 1.12	$ 1.12	$ 1.12	$ 1.12	$ 1.12	$ 1.12	$ 1.12	$ 1.12	$ 1.12	$ 1.12	
63	Parker-Davis Transmission Cost - $	$ 684.29	$ 684.29	$ 684.29	$ 702.27	$ 702.27	$ 702.27	$ 702.27	$ 702.27	$ 702.27	$ 684.29	$ 684.29	$ 684.29	$ 8,319.37
64	Max Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
65	Scheduled Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
66	Energy $/kWh	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	
67	Scheduled Energy Cost	$ 2,376.66	$ 2,146.66	$ 2,376.66	$ 2,198.93	$ 2,272.22	$ 2,198.93	$ 2,272.22	$ 2,272.22	$ 2,198.93	$ 2,376.66	$ 2,300.00	$ 2,376.66	$ 27,366.76
68	Load Factor - %	53.1%	53.1%	53.1%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	53.1%	53.1%	53.1%	50.6%
69	Total CRSP Cost	$ 5,620.71	$ 5,390.71	$ 5,620.71	$ 5,528.21	$ 5,601.50	$ 5,528.21	$ 5,601.50	$ 5,601.50	$ 5,528.21	$ 5,620.71	$ 5,544.05	$ 5,620.71	$ 66,806.74
70	Average CRSP Cost - kWh	$ 23.37	$ 24.82	$ 23.37	$ 24.85	$ 24.37	$ 24.85	$ 24.37	$ 24.37	$ 24.85	$ 23.37	$ 23.82	$ 23.37	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	CRSP Allocation	S	W			Hualapai								
2	CROD	625	609		CRSP SLCIP RESOURCES									
3	Energy	1,357,114	1,411,736											
4		January	February	March	April	May	June	July	August	September	October	November	December	Total
5		<<—— WINTER SEASON ——>>			<<—— SUMMER SEASON ——>>						<<—— WINTER SEASON ——>>			
6	- Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
71	WRP Energy - kWh	212,635	192,058	212,635	227,522	235,106	227,522	235,106	235,106	227,522	212,635	205,776	212,635	2,636,262
72	WRP - $/MWH	50	50	50	50	50	50	50	50	50	50	50	50	
73	WRP Cost	$ 10,631.77	$ 9,602.89	$ 10,631.77	$ 11,376.11	$ 11,755.32	$ 11,376.11	$ 11,755.32	$ 11,755.32	$ 11,376.11	$ 10,631.77	$ 10,288.81	$ 10,631.77	$ 131,813.10
74	Total CRSP Plus WRP Cost	$ 16,252.49	$ 14,993.61	$ 16,252.49	$ 16,904.32	$ 17,356.82	$ 16,904.32	$ 17,356.82	$ 17,356.82	$ 16,904.32	$ 16,252.49	$ 15,832.86	$ 16,252.49	$ 198,619.84
75	Total Max Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
76	Scheduled Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
77	Aggregate Scheduled Load Factor	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	98.7%
78	eduled Aggregate Average Cost $/MWH	$ 35.87	$ 36.64	$ 35.87	$ 37.57	$ 37.33	$ 37.57	$ 37.33	$ 37.33	$ 37.57	$ 35.87	$ 36.11	$ 35.87	$ 36.75
79														
80	CRSP At Delivery													
81	Max Capacity - kW	585	585	585	600	600	600	600	600	600	585	585	585	600
82	Max Energy - kWh	434,972	392,878	434,972	432,000	446,400	432,000	446,400	446,400	432,000	434,972	420,941	434,972	5,188,908
83	Scheduled Capacity - kW	585	585	585	600	600	600	600	600	600	585	585	585	
84	Scheduled Energy - kWh	434,972	392,878	434,972	432,000	446,400	432,000	446,400	446,400	432,000	434,972	420,941	434,972	
85	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
86														
87	CRSP At Nelson													
88	Max Capacity - kW	561	561	561	576	576	576	576	576	576	561	561	561	
89	Max Energy - kWh	417,573	377,163	417,573	414,720	428,544	414,720	428,544	428,544	414,720	417,573	404,103	417,573	
90	Scheduled Capacity - kW	561	561	561	576	576	576	576	576	576	561	561	561	
91	Scheduled Energy - kWh	417,573	377,163	417,573	414,720	428,544	414,720	428,544	428,544	414,720	417,573	404,103	417,573	
92	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
93														
94	CRSP At Customer Meter													
95	Max Capacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
96	Scheduled Capacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
97	Max Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097
98	Scheduled Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097
99	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
100	Scheduled Average Cost $/MWH	$ 40.54	$ 41.41	$ 40.54	$ 42.46	$ 42.19	$ 42.46	$ 42.19	$ 42.19	$ 42.46	$ 40.54	$ 40.81	$ 40.54	$ 41.53
101														
102	2009													
103	CRSP AT CRSP Delivery													
104	Escalation Rate - %	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
105	Max Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
106	Scheduled Capacity	609	609	609	625	625	625	625	625	625	609	609	609	625
107	Capacity $/kW/Month	4.29	4.29	4.29	4.29	4.29	4.29	4.29	4.29	4.29	4.29	4.29	4.29	
108	Scheduled Capacity Cost	$ 2,610.95	$ 2,610.95	$ 2,610.95	$ 2,679.55	$ 2,679.55	$ 2,679.55	$ 2,679.55	$ 2,679.55	$ 2,679.55	$ 2,610.95	$ 2,610.95	$ 2,610.95	$ 31,743.02
109	Parker-Davis Transmission Cost - $/kW	$ 1.15	$ 1.15	$ 1.15	$ 1.15	$ 1.15	$ 1.15	$ 1.15	$ 1.15	$ 1.15	$ 1.15	$ 1.15	$ 1.15	
110	Parker-Davis Transmission Cost - $	$ 697.98	$ 697.98	$ 697.98	$ 716.32	$ 716.32	$ 716.32	$ 716.32	$ 716.32	$ 716.32	$ 697.98	$ 697.98	$ 697.98	$ 8,485.76
111	Max Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
112	Scheduled Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
113	Energy $/kWh	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	
114	Scheduled Energy Cost	$ 2,424.20	$ 2,189.60	$ 2,424.20	$ 2,242.90	$ 2,317.67	$ 2,242.90	$ 2,317.67	$ 2,317.67	$ 2,242.90	$ 2,424.20	$ 2,346.00	$ 2,424.20	$ 27,914.09
115	Load Factor - %	53.1%	53.1%	53.1%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	53.1%	53.1%	53.1%	50.6%
116	Total CRSP Cost	$ 5,733.13	$ 5,498.53	$ 5,733.13	$ 5,638.77	$ 5,713.53	$ 5,638.77	$ 5,713.53	$ 5,713.53	$ 5,638.77	$ 5,733.13	$ 5,654.93	$ 5,733.13	$ 68,142.88
117	Average CRSP Cost - kWh	$ 23.84	$ 25.32	$ 23.84	$ 25.35	$ 24.85	$ 25.35	$ 24.85	$ 24.85	$ 25.35	$ 23.84	$ 24.30	$ 23.84	
118	WRP Energy - kWh	212,635	192,058	212,635	227,522	235,106	227,522	235,106	235,106	227,522	212,635	205,776	212,635	2,636,262
119	WRP - $/MWH	50	50	50	50	50	50	50	50	50	50	50	50	
120	WRP Cost	$ 10,631.77	$ 9,602.89	$ 10,631.77	$ 11,376.11	$ 11,755.32	$ 11,376.11	$ 11,755.32	$ 11,755.32	$ 11,376.11	$ 10,631.77	$ 10,288.81	$ 10,631.77	$ 131,813.10
121	Total CRSP Plus WRP Cost	$ 16,364.90	$ 15,101.42	$ 16,364.90	$ 17,014.88	$ 17,468.85	$ 17,014.88	$ 17,468.85	$ 17,468.85	$ 17,014.88	$ 16,364.90	$ 15,943.74	$ 16,364.90	$ 199,955.98
122	Total Max Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
123	Scheduled Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
124	Aggregate Scheduled Load Factor	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	98.7%
125	eduled Aggregate Average Cost $/MWH	$ 36.12	$ 36.90	$ 36.12	$ 37.81	$ 37.57	$ 37.81	$ 37.57	$ 37.57	$ 37.81	$ 36.12	$ 36.36	$ 36.12	$ 36.99
126														
127	CRSP At Delivery													
128	Max Capacity - kW	585	585	585	600	600	600	600	600	600	585	585	585	600
129	Max Energy - kWh	434,972	392,878	434,972	432,000	446,400	432,000	446,400	446,400	432,000	434,972	420,941	434,972	5,188,908
130	Scheduled Capacity - kW	585	585	585	600	600	600	600	600	600	585	585	585	
131	Scheduled Energy - kWh	434,972	392,878	434,972	432,000	446,400	432,000	446,400	446,400	432,000	434,972	420,941	434,972	
132	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
133														
134	CRSP At Nelson													

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	CRSP Allocation	S	W			Hualapai								
2	CROD	625	609			CRSP SLCIP RESOURCES								
3	Energy	1,357,114	1,411,736											
4		January	February	March	April	May	June	July	August	September	October	November	December	Total
5			<<—— WINTER SEASON ——>>			<<—— SUMMER SEASON		——>>				<<—— WINTER SEASON ——>>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
135	Max Capacity - kW	561	561	561	576	576	576	576	576	576	561	561	561	
136	Max Energy - kWh	417,573	377,163	417,573	414,720	428,544	414,720	428,544	428,544	414,720	417,573	404,103	417,573	
137	Scheduled Capacity - kW	561	561	561	576	576	576	576	576	576	561	561	561	
138	Scheduled Energy - kWh	417,573	377,163	417,573	414,720	428,544	414,720	428,544	428,544	414,720	417,573	404,103	417,573	
139	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
140														
141	CRSP At Customer Meter													
142	Max Capacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
143	Scheduled Capacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
144	Max Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097
145	Scheduled Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097
146	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
147	Scheduled Average Cost $/MWH	$ 40.82	$ 41.71	$ 40.82	$ 42.74	$ 42.46	$ 42.74	$ 42.46	$ 42.46	$ 42.74	$ 40.82	$ 41.10	$ 40.82	$ 41.81
148														
149	2010													
150	CRSP AT CRSP Delivery													
151	Escalation Rate - %	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
152	Max Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
153	Scheduled Capacity	609	609	609	625	625	625	625	625	625	609	609	609	625
154	Capacity $/kW/Month	4.37	4.37	4.37	4.37	4.37	4.37	4.37	4.37	4.37	4.37	4.37	4.37	
155	Scheduled Capacity Cost	$ 2,663.17	$ 2,663.17	$ 2,663.17	$ 2,733.14	$ 2,733.14	$ 2,733.14	$ 2,733.14	$ 2,733.14	$ 2,733.14	$ 2,663.17	$ 2,663.17	$ 2,663.17	$ 32,377.88
156	Parker-Davis Transmission Cost - $/kW	$ 1.17	$ 1.17	$ 1.17	$ 1.17	$ 1.17	$ 1.17	$ 1.17	$ 1.17	$ 1.17	$ 1.17	$ 1.17	$ 1.17	
157	Parker-Davis Transmission Cost - $	$ 711.94	$ 711.94	$ 711.94	$ 730.64	$ 730.64	$ 730.64	$ 730.64	$ 730.64	$ 730.64	$ 711.94	$ 711.94	$ 711.94	$ 8,655.47
158	Max Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
159	Scheduled Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
160	Energy $/kWh	0.0103	0.0103	0.0103	0.0103	0.0103	0.0103	0.0103	0.0103	0.0103	0.0103	0.0103	0.0103	
161	Scheduled Energy Cost	$ 2,472.68	$ 2,233.39	$ 2,472.68	$ 2,287.76	$ 2,364.02	$ 2,287.76	$ 2,364.02	$ 2,364.02	$ 2,287.76	$ 2,472.68	$ 2,392.92	$ 2,472.68	$ 28,472.38
162	Load Factor - %	53.1%	53.1%	53.1%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	53.1%	53.1%	53.1%	50.6%
163	Total CRSP Cost	$ 5,847.79	$ 5,608.50	$ 5,847.79	$ 5,751.54	$ 5,827.80	$ 5,751.54	$ 5,827.80	$ 5,827.80	$ 5,751.54	$ 5,847.79	$ 5,768.03	$ 5,847.79	$ 69,505.73
164	Average CRSP Cost - kWh	$ 24.32	$ 25.82	$ 24.32	$ 25.85	$ 25.35	$ 25.85	$ 25.35	$ 25.35	$ 25.85	$ 24.32	$ 24.79	$ 24.32	
165	WRP Energy - kWh	212,635	192,058	212,635	227,522	235,106	227,522	235,106	235,106	227,522	212,635	205,776	212,635	2,636,262
166	WRP - $/MWH	50	50	50	50	50	50	50	50	50	50	50	50	
167	WRP Cost	$ 10,631.77	$ 9,602.89	$ 10,631.77	$ 11,376.11	$ 11,755.32	$ 11,376.11	$ 11,755.32	$ 11,755.32	$ 11,376.11	$ 10,631.77	$ 10,288.81	$ 10,631.77	$ 131,813.10
168	Total CRSP Plus WRP Cost	$ 16,479.56	$ 15,211.39	$ 16,479.56	$ 17,127.66	$ 17,583.12	$ 17,127.66	$ 17,583.12	$ 17,583.12	$ 17,127.66	$ 16,479.56	$ 16,056.84	$ 16,479.56	$ 201,318.83
169	Total Max Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
170	Scheduled Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
171	Aggregate Scheduled Load Factor	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	98.7%
172	eduled Aggregate Average Cost $/MWH	$ 36.37	$ 37.17	$ 36.37	$ 38.06	$ 37.81	$ 38.06	$ 37.81	$ 37.81	$ 38.06	$ 36.37	$ 36.62	$ 36.37	$ 37.25
173														
174	CRSP At Delivery													
175	Max Capacity - kW	585	585	585	600	600	600	600	600	600	585	585	585	600
176	Max Energy - kWh	434,972	392,878	434,972	432,000	446,400	432,000	446,400	446,400	432,000	434,972	420,941	434,972	5,188,908
177	Scheduled Capacity - kW	585	585	585	600	600	600	600	600	600	585	585	585	
178	Scheduled Energy - kWh	434,972	392,878	434,972	432,000	446,400	432,000	446,400	446,400	432,000	434,972	420,941	434,972	
179	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
180														
181	CRSP At Nelson													
182	Max Capacity - kW	561	561	561	576	576	576	576	576	576	561	561	561	
183	Max Energy - kWh	417,573	377,163	417,573	414,720	428,544	414,720	428,544	428,544	414,720	417,573	404,103	417,573	
184	Scheduled Capacity - kW	561	561	561	576	576	576	576	576	576	561	561	561	
185	Scheduled Energy - kWh	417,573	377,163	417,573	414,720	428,544	414,720	428,544	428,544	414,720	417,573	404,103	417,573	
186	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
187														
188	CRSP At Customer Meter													
189	Max Capacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
190	Scheduled Capacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
191	Max Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097
192	Scheduled Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097
193	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
194	Scheduled Average Cost $/MWH	$ 41.11	$ 42.01	$ 41.11	$ 43.02	$ 42.74	$ 43.02	$ 42.74	$ 42.74	$ 43.02	$ 41.11	$ 41.39	$ 41.11	$ 42.10
195														
196	2011													
197	CRSP AT CRSP Delivery													
198	Escalation Rate - %	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	

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	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	CRSP Allocation	S	W			Hualapai								
2	CROD	625	609			CRSP SLCIP RESOURCES								
3	Energy	1,357,114	1,411,736											
4		January	February	March	April	May	June	July	August	September	October	November	December	Total
5		<<———— WINTER SEASON	————>>		<<		———— SUMMER SEASON	————		————>>	<<————	WINTER SEASON	————>>	
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
199	Max Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
200	Scheduled Capacity	609	609	609	625	625	625	625	625	625	609	609	609	625
201	Capacity $/kW/Month	4.46	4.46	4.46	4.46	4.46	4.46	4.46	4.46	4.46	4.46	4.46	4.46	
202	Scheduled Capacity Cost	$ 2,716.44	$ 2,716.44	$ 2,716.44	$ 2,787.80	$ 2,787.80	$ 2,787.80	$ 2,787.80	$ 2,787.80	$ 2,787.80	$ 2,716.44	$ 2,716.44	$ 2,716.44	$ 33,025.44
203	Parker-Davis Transmission Cost - $/kW	$ 1.19	$ 1.19	$ 1.19	$ 1.19	$ 1.19	$ 1.19	$ 1.19	$ 1.19	$ 1.19	$ 1.19	$ 1.19	$ 1.19	
204	Parker-Davis Transmission Cost - $	$ 726.18	$ 726.18	$ 726.18	$ 745.25	$ 745.25	$ 745.25	$ 745.25	$ 745.25	$ 745.25	$ 726.18	$ 726.18	$ 726.18	$ 8,828.58
205	Max Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
206	Scheduled Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
207	Energy $/kWh	0.0105	0.0105	0.0105	0.0105	0.0105	0.0105	0.0105	0.0105	0.0105	0.0105	0.0105	0.0105	
208	Scheduled Energy Cost	$ 2,522.13	$ 2,278.06	$ 2,522.13	$ 2,333.52	$ 2,411.30	$ 2,333.52	$ 2,411.30	$ 2,411.30	$ 2,333.52	$ 2,522.13	$ 2,440.78	$ 2,522.13	$ 29,041.82
209	Load Factor - %	53.1%	53.1%	53.1%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	53.1%	53.1%	53.1%	50.6%
210	Total CRSP Cost	$ 5,964.75	$ 5,720.67	$ 5,964.75	$ 5,866.58	$ 5,944.36	$ 5,866.58	$ 5,944.36	$ 5,944.36	$ 5,866.58	$ 5,964.75	$ 5,883.39	$ 5,964.75	$ 70,895.85
211	Average CRSP Cost - kWh	$ 24.81	$ 26.34	$ 24.81	$ 26.37	$ 25.86	$ 26.37	$ 25.86	$ 25.86	$ 26.37	$ 24.81	$ 25.28	$ 24.81	
212	WRP Energy - kWh	212,635	192,058	212,635	227,522	235,106	227,522	235,106	235,106	227,522	212,635	205,776	212,635	2,636,262
213	WRP - $/MWH	50	50	50	50	50	50	50	50	50	50	50	50	
214	WRP Cost	$ 10,631.77	$ 9,602.89	$ 10,631.77	$ 11,376.11	$ 11,755.32	$ 11,376.11	$ 11,755.32	$ 11,755.32	$ 11,376.11	$ 10,631.77	$ 10,288.81	$ 10,631.77	$ 131,813.10
215	Total CRSP Plus WRP Cost	$ 16,596.52	$ 15,323.56	$ 16,596.52	$ 17,242.69	$ 17,699.68	$ 17,242.69	$ 17,699.68	$ 17,699.68	$ 17,242.69	$ 16,596.52	$ 16,172.20	$ 16,596.52	$ 202,708.95
216	Total Max Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
217	Scheduled Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
218	Aggregate Scheduled Load Factor	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	98.7%
219	eduled Aggregate Average Cost $/MWH	$ 36.63	$ 37.44	$ 36.63	$ 38.32	$ 38.06	$ 38.32	$ 38.06	$ 38.06	$ 38.32	$ 36.63	$ 36.88	$ 36.63	$ 37.50
220														
221	CRSP At Delivery													
222	Max Capacity - kW	585	585	585	600	600	600	600	600	600	585	585	585	600
223	Max Energy - kWh	434,972	392,878	434,972	432,000	446,400	432,000	446,400	446,400	432,000	434,972	420,941	434,972	5,188,908
224	Scheduled Capacity - kW	585	585	585	600	600	600	600	600	600	585	585	585	
225	Scheduled Energy - kWh	434,972	392,878	434,972	432,000	446,400	432,000	446,400	446,400	432,000	434,972	420,941	434,972	
226	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
227														
228	CRSP At Nelson													
229	Max Capacity - kW	561	561	561	576	576	576	576	576	576	561	561	561	
230	Max Energy - kWh	417,573	377,163	417,573	414,720	428,544	414,720	428,544	428,544	414,720	417,573	404,103	417,573	
231	Scheduled Capacity - kW	561	561	561	576	576	576	576	576	576	561	561	561	
232	Scheduled Energy - kWh	417,573	377,163	417,573	414,720	428,544	414,720	428,544	428,544	414,720	417,573	404,103	417,573	
233	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
234			584.64	561.2544	538.804224									
235	CRSP At Customer Meter													
236	Max Capacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
237	Scheduled Capacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
238	Max Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097
239	Scheduled Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097
240	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
241	Scheduled Average Cost $/MWH	$ 41.40	$ 42.32	$ 41.40	$ 43.31	$ 43.02	$ 43.31	$ 43.02	$ 43.02	$ 43.31	$ 41.40	$ 41.69	$ 41.40	$ 42.39
242		$ 16,596.52	$ 15,323.56	$ 16,596.52	$ 17,242.69	$ 17,699.68	$ 17,242.69	$ 17,699.68	$ 17,699.68	$ 17,242.69	$ 16,596.52	$ 16,172.20	$ 16,596.52	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						Supplemental RESOURCES								
3														
4		January	February	March	April	May	June	July	August	September	October	November	December	Total
5		<<——— WINTER SEASON ———>>				<<——— SUMMER SEASON ———>>						<<—— WINTER SEASON ——>>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
7	Year	2,007	2,008	2,009	2,010	2,011								
8	Purchased Power Escalation Rate - %	0.0%	2.0%	2.0%	2.0%	2.0%								
9														
10	2007													
11	Supplemental At CRSP													
12	Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Load Factor - %	-	-	-	-	-	-	-	-	-	-	-	-	-
15														
16	Supplemental At Transmission													
17	Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
18	Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
19	Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
20														
21	Supplemental At Nelson													
22	Capacity - kW	1,502	1,596	1,498	1,295	1,252	966	1,364	1,197	1,178	1,034	1,347	1,513	
23	Capacity $/kW/Month	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	
24	Capacity Cost	$ 3,003.32	$ 3,191.04	$ 2,995.66	$ 2,590.47	$ 2,503.49	$ 1,932.08	$ 2,727.60	$ 2,393.10	$ 2,356.02	$ 2,068.86	$ 2,693.02	$ 3,026.97	
25	Energy - kWh	126,836	169,756	138,540	64,328	44,047	34,731	167,716	59,555	105,556	19,995	124,887	174,790	
26	Energy $/kWh	0.0650	0.0650	0.0650	0.0650	0.0650	0.0650	0.0650	0.0650	0.0650	0.0650	0.0650	0.0650	
27	Energy Cost	$ 8,244	$ 11,034	$ 9,005	$ 4,181	$ 2,863	$ 2,258	$ 10,902	$ 3,871	$ 6,861	$ 1,300	$ 8,118	$ 11,361	
28	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
29	Total Supplemental Cost	$ 11,248	$ 14,225	$ 12,001	$ 6,772	$ 5,367	$ 4,190	$ 13,629	$ 6,264	$ 9,217	$ 3,369	$ 10,811	$ 14,388	$ -
30														
31	Supplemental At Customer Meter													
32	Capacity - kW	1,442	1,532	1,438	1,243	1,202	927	1,309	1,149	1,131	993	1,293	1,453	
33	Energy - kWh	121,762	162,966	132,998	61,755	42,285	33,342	161,007	57,172	101,334	19,195	119,892	167,798	1,181,507
34	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
35	Average Cost $/MWH	$ 92.37	$ 87.29	$ 90.23	$ 109.66	$ 126.91	$ 125.66	$ 84.65	$ 109.57	$ 90.96	$ 175.49	$ 90.17	$ 85.75	
36														
37	2008													
38	Supplemental At CRSP													
39	Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
41	Load Factor - %	-	-	-	-	-	-	-	-	-	-	-	-	-
42														
43	Supplemental At Transmission													
44	Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
45	Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
46	Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
47														
48	Supplemental At Nelson													
49	Capacity - kW	1,780	1,908	1,791	1,582	1,535	1,261	1,383	1,214	1,196	1,050	1,366	1,534	
50	Capacity $/kW/Month	2.04	2.04	2.04	2.04	2.04	2.04	2.04	2.04	2.04	2.04	2.04	2.04	
51	Capacity Cost	$ 3,630.56	$ 3,893.00	$ 3,653.48	$ 3,226.51	$ 3,132.26	$ 2,572.74	$ 2,821.72	$ 2,477.13	$ 2,438.92	$ 2,142.79	$ 2,785.80	$ 3,129.84	$ 35,904.76
52	Energy - kWh	161,329	204,264	172,479	94,010	73,475	65,309	173,678	64,436	110,759	24,371	130,177	180,714	
53	Energy $/kWh	0.0663	0.0663	0.0663	0.0663	0.0663	0.0663	0.0663	0.0663	0.0663	0.0663	0.0663	0.0663	
54	Energy Cost	$ 10,696	$ 13,543	$ 11,435	$ 6,233	$ 4,871	$ 4,330	$ 11,515	$ 4,272	$ 7,343	$ 1,616	$ 8,631	$ 11,981	$ 96,466.53
55	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
56	Total Supplemental Cost	$ 14,327	$ 17,436	$ 15,089	$ 9,459	$ 8,004	$ 6,903	$ 14,337	$ 6,749	$ 9,782	$ 3,759	$ 11,417	$ 15,111	$ 132,371.29
57														
58	Supplemental At Customer Meter													
59	Capacity - kW	1,708	1,832	1,719	1,518	1,474	1,211	1,328	1,166	1,148	1,008	1,311	1,473	
60	Energy - kWh	154,876	196,094	165,580	90,250	70,536	62,697	166,731	61,858	106,328	23,396	124,970	173,485	1,396,800
61	Loss Factor- %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
62	Average Cost $/MWH	$ 92.50	$ 88.92	$ 91.13	$ 104.81	$ 113.47	$ 110.10	$ 85.99	$ 109.11	$ 92.00	$ 160.65	$ 91.35	$ 87.10	
63														
64	2009													
65	Supplemental At CRSP													
66	Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
67	Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
68	Load Factor - %	-	-	-	-	-	-	-	-	-	-	-	-	-
69														
70	Supplemental At Transmission													

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	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						Supplemental RESOURCES								
3														
4		January	February	March	April	May	June	July	August	September	October	November	December	Total
5		<<----	WINTER SEASON	---->>		<<----		SUMMER SEASON			---->>	<<---- WINTER SEASON ---->>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
71	Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
72	Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
73	Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
74														
75	Supplemental At Nelson													
76	Capacity - kW	1,803	1,933	1,814	1,603	1,557	1,280	1,403	1,232	1,213	1,067	1,385	1,555	
77	Capacity $/kW/Month	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	
78	Capacity Cost	$ 3,751.88	$ 4,022.25	$ 3,775.50	$ 3,335.94	$ 3,238.84	$ 2,662.43	$ 2,918.93	$ 2,563.92	$ 2,524.56	$ 2,219.18	$ 2,881.61	$ 3,236.04	$ 37,131.07
79	Energy - kWh	167,118	210,079	178,379	99,098	78,495	70,109	179,700	69,365	116,014	28,790	135,520	186,697	
80	Energy $/kWh	0.0676	0.0676	0.0676	0.0676	0.0676	0.0676	0.0676	0.0676	0.0676	0.0676	0.0676	0.0676	
81	Energy Cost	$ 11,302	$ 14,207	$ 12,063	$ 6,702	$ 5,308	$ 4,741	$ 12,152	$ 4,691	$ 7,846	$ 1,947	$ 9,165	$ 12,626	$ 102,748.50
82	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
83	Total Supplemental Cost	$ 15,053	$ 18,229	$ 15,839	$ 10,038	$ 8,547	$ 7,404	$ 15,071	$ 7,255	$ 10,370	$ 4,166	$ 12,046	$ 15,862	$ 139,879.58
84														
85	Supplemental At Customer Meter													
86	Capacity - kW	1,731	1,856	1,742	1,539	1,494	1,228	1,347	1,183	1,165	1,024	1,329	1,493	
87	Energy - kWh	160,433	201,676	171,244	95,134	75,355	67,305	172,512	66,591	111,373	27,639	130,099	179,229	1,458,589
88	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
89	Average Cost $/MWH	$ 93.83	$ 90.39	$ 92.49	$ 105.51	$ 113.42	$ 110.00	$ 87.36	$ 108.95	$ 93.11	$ 150.74	$ 92.59	$ 88.50	
90														
91	2010													
92	Supplemental At CRSP													
93	Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
94	Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
95	Energy $/kWh	-	-	-	-	-	-	-	-	-	-	-	-	
96														
97	Supplemental At Transmission													
98	Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
99	Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
100	Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
101														
102	Supplemental At Nelson													
103	Capacity - kW	1,827	1,958	1,838	1,625	1,578	1,298	1,423	1,250	1,231	1,083	1,404	1,576	
104	Capacity $/kW/Month	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	
105	Capacity Cost	$ 3,877.10	$ 4,155.63	$ 3,901.43	$ 3,448.91	$ 3,348.87	$ 2,755.06	$ 3,019.30	$ 2,653.58	$ 2,613.03	$ 2,298.11	$ 2,980.55	$ 3,345.68	$ 38,397.25
106	Energy - kWh	172,965	215,951	184,339	104,236	83,566	74,958	185,783	74,344	121,321	33,254	140,916	192,739	
107	Energy $/kWh	0.0690	0.0690	0.0690	0.0690	0.0690	0.0690	0.0690	0.0690	0.0690	0.0690	0.0690	0.0690	
108	Energy Cost	$ 11,931	$ 14,896	$ 12,715	$ 7,190	$ 5,764	$ 5,170	$ 12,815	$ 5,128	$ 8,369	$ 2,294	$ 9,720	$ 13,295	$ 109,287.57
109	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
110	Total Supplemental Cost	$ 15,808	$ 19,052	$ 16,617	$ 10,639	$ 9,113	$ 7,926	$ 15,834	$ 7,782	$ 10,982	$ 4,592	$ 12,701	$ 16,641	$ 147,684.82
111														
112	Supplemental At Customer Meter													
113	Capacity - kW	1,754	1,880	1,765	1,560	1,515	1,246	1,366	1,200	1,182	1,039	1,348	1,513	
114	Energy - kWh	166,046	207,313	176,965	100,066	80,223	71,959	178,352	71,371	116,468	31,924	135,279	185,030	1,520,996
115	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
116	Average Cost $/MWH	$ 95.20	$ 91.90	$ 93.90	$ 106.32	$ 113.60	$ 110.14	$ 88.78	$ 109.03	$ 94.29	$ 143.84	$ 93.89	$ 89.93	
117														
118	2011													
119	Supplemental At CRSP													
120	Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
121	Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
122	Load Factor - %	-	-	-	-	-	-	-	-	-	-	-	-	-
123														
124	Supplemental At Transmission													
125	Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
126	Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
127	Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
128														
129	Supplemental At Nelson													
130	Capacity - kW	1,851	1,983	1,862	1,647	1,599	1,317	1,443	1,269	1,249	1,099	1,424	1,598	
131	Capacity $/kW/Month	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	
132	Capacity Cost	$ 4,006.34	$ 4,293.28	$ 4,031.40	$ 3,565.54	$ 3,462.48	$ 2,850.73	$ 3,122.96	$ 2,746.18	$ 2,704.41	$ 2,379.67	$ 3,082.71	$ 3,458.87	$ 39,704.57
133	Energy - kWh	178,870	221,882	190,358	109,425	88,687	79,854	191,926	79,373	126,681	37,762	146,366	198,842	
134	Energy $/kWh	0.0704	0.0704	0.0704	0.0704	0.0704	0.0704	0.0704	0.0704	0.0704	0.0704	0.0704	0.0704	

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	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						Supplemental RESOURCES								
3														
4		January	February	March	April	May	June	July	August	September	October	November	December	Total
5		<<—— WINTER SEASON ——>>				<<—— SUMMER SEASON ——>>						<<—— WINTER SEASON ——>>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
135	Energy Cost	$ 12,585	$ 15,611	$ 13,393	$ 7,699	$ 6,240	$ 5,618	$ 13,504	$ 5,585	$ 8,913	$ 2,657	$ 10,298	$ 13,990	$ 116,092.84
136	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
137	Total Supplemental Cost	$ 16,591	$ 19,904	$ 17,425	$ 11,264	$ 9,702	$ 8,469	$ 16,627	$ 8,331	$ 11,617	$ 5,037	$ 13,381	$ 17,449	$ 155,797.41
138														
139	**Supplemental At Customer Motor**													
140	Capacity - kW	1,777	1,904	1,788	1,581	1,535	1,264	1,385	1,218	1,199	1,055	1,367	1,534	
141	Energy - kWh	171,715	213,007	182,744	105,048	85,139	76,660	184,249	76,198	121,614	36,252	140,512	190,889	1,584,027
142	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
143	Average Cost $/MWH	$ 96.62	$ 93.45	$ 95.35	$ 107.23	$ 113.96	$ 110.48	$ 90.24	$ 109.33	$ 95.53	$ 138.93	$ 95.23	$ 91.41	

BASE CASE - Debtservice

	A	B	C	D	E	F	G	H
1		Pre FY2007 Loan 1	Wind Turbines	FY2007	FY2008	FY2009	FY2010	FY2011
2								
3	Adjustment Percent			0.0%	0.0%	0.0%	0.0%	0.0%
4	Facilities			$ 210,000	$ -	$ -	$ -	$ -
5	Equipment			$ -	$ 200,000	$ 200,000	$ 200,000	$ 200,000
6	Total	0	$ -	$ 210,000	$ 200,000	$ 200,000	$ 200,000	$ 200,000
7								
8	Principal amount	$ -	$ -	$ (210,000)	$ (200,000)	$ (200,000)	$ (200,000)	$ (200,000)
9	Annual Interest Rate	8.00%	5.50%	8.00%	8.0%	8.0%	8.0%	8.0%
10	Interest Rate	0.6667%	0.4583%	0.6667%	0.6667%	0.6667%	0.6667%	0.6667%
11	Number of Years	30	20	30	30	30	30	30
12	Number of Payments	360	240	360	360	360	360	360
13	Payment Due	1	1	1	1	1	1	1
14	Levelized Pymt Amt	$0.00	$0.00	$1,530.70	$1,457.81	$1,457.81	$1,457.81	$1,457.81
15	Annual Payment	$0.00	$0.00	$18,368.41				
16								
17								
18		Annual Summary						
19		**FY2007**	**FY2008**	**FY2009**	**FY2010**	**FY2011**		
20	Wind Turbines	$ -	$ -	$ -	$ -	$ -		
21	FY2007	$ 18,368	$ 18,368	$ 18,368	$ 18,368	$ 18,368		
22	FY2008	$ -	$ 17,494	$ 17,494	$ 17,494	$ 17,494		
23	FY2009	$ -	$ -	$ 17,494	$ 17,494	$ 17,494		
24	FY2010	$ -	$ -	$ -	$ 17,494	$ 17,494		
25	FY2011	$ -	$ -	$ -	$ -	$ 17,494		
26	Total Debt Service	$ 18,368	$ 35,862	$ 53,356	$ 70,850	$ 88,343		

See Assumptions worksheet. Based upon 1/2 (RCNLD + OCLD)

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CASE A PEACH SPRINGS

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						RESOURCES VERSUS LOADS								
3		January	February	March	April	May	June	July	August	September	October	November	December	Total
4	CRSP Season	<<—— WINTER SEASON ——>>			<<—— SUMMER SEASON ——>>						<<—— WINTER SEASON ——>>			
5	Supplemental Season	<<—— WINTER SEASON ——>>				<<—— SUMMER SEASON ——>>						<<—— WINTER SEASON ——>>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
7	2007													
8	RESOURCES													
9	At CRSP Delivery													
10	CRSP Available Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
11	CRSP Available Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
12	Max WRP kWh	212,635	192,058	212,635	227,522	235,106	227,522	235,106	235,106	227,522	212,635	205,776	212,635	2,636,262
13	Max CRSP Aggregate kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
14	Renewable Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Renewable Scheduled Capacity - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Supplemental Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Supplemental Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Total Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
19	Total Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
20	At Meter													
21	CRSP AvailableCapacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
22	CRSP & WRP Available Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097
23	Renewable Scheduled Capacity - kW	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
24	Renewable Scheduled Capacity - kWh	197,470	203,546	276,458	309,876	331,142	343,294	306,838	267,344	224,812	203,546	182,280	191,394	3,038,000
25	Supplemental Capacity - kW	0	62	0	0	0	0	0	0	0	0	0	0	62
26	Supplemental Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Total Capacity - kW	2,009	2,071	2,009	2,023	2,023	2,023	2,023	2,023	2,023	2,009	2,009	2,009	2,071
28	Total Energy -kWh	598,340	565,622	677,328	708,007	742,544	741,425	718,240	678,746	622,943	604,416	570,219	592,264	7,820,097
29														
30	Load At Meter													
31	Demand													
32	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
33	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
34	Hualapai Peach Springs Area	1,980	2,071	1,977	1,796	1,755	1,480	1,862	1,702	1,684	1,532	1,831	1,992	
35	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
36	**Demand Subtotal**	**1,980**	**2,071**	**1,977**	**1,796**	**1,755**	**1,480**	**1,862**	**1,702**	**1,684**	**1,532**	**1,831**	**1,992**	2,071
37	Energy													
38	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
39	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
40	Hualapai Peach Springs Area	522,633	525,042	533,869	459,886	453,687	431,473	572,409	468,575	499,465	420,066	507,831	568,669	
41	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
42	**Energy Subtotal**	**522,633**	**525,042**	**533,869**	**459,886**	**453,687**	**431,473**	**572,409**	**468,575**	**499,465**	**420,066**	**507,831**	**568,669**	5,963,604
43														
44	Resource Vs. Load At Meter													
45	Capacity Excess/(Deficiency) {1}	28	-	32	227	268	543	161	321	339	477	177	17	543
46	Energy Excess/(Deficiency) {2}	75,708	40,580	143,460	248,121	288,857	309,952	145,831	210,172	123,478	184,351	62,388	23,596	1,856,493
47														
48	2008													
49	RESOURCES													
50	At CRSP Delivery													
51	CRSP Available Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
52	CRSP Available Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
53	WRP kWh	212,635	192,058	212,635	227,522	235,106	227,522	235,106	235,106	227,522	212,635	205,776	212,635	2,636,262
54	Aggregate kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
55	Renewable Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
56	Renewable Scheduled Capacity - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
57	Supplemental Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
58	Supplemental Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
59	Total Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
60	Total Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
61	At Meter													
62	CRSP AvailableCapacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
63	CRSP & WRP Available Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097
64	Renewable Scheduled Capacity - kW	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
65	Renewable Scheduled Capacity - kWh	197,470	203,546	276,458	309,876	331,142	343,294	306,838	267,344	224,812	203,546	182,280	191,394	3,038,000
66	Supplemental Capacity - kW	238	362	249	48	4	0	0	0	0	0	0	3	362

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	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1					Hualapai									
2					RESOURCES VERSUS LOADS									
3		January	February	March	April	May	June	July	August	September	October	November	December	Total
4	CRSP Season	<<——— WINTER SEASON ———>>			<<——— SUMMER SEASON ———>>						<<——— WINTER SEASON ———>>			
5	Supplemental Season	<<——— WINTER SEASON ———>>				<<——— SUMMER SEASON ———>>						<<—— WINTER SEASON ——>>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
67	Supplemental Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
68	Total Capacity - kW	2,247	2,371	2,258	2,071	2,027	2,023	2,023	2,023	2,023	2,009	2,009	2,012	2,371
69	Total Energy -kWh	598,340	565,622	677,328	708,007	742,544	741,425	718,240	678,746	622,943	604,416	570,219	592,264	7,820,097
70														
71	Load At Meter													
72	Demand													
73	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
74	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
75	Hualapai Peach Springs Area	2,247	2,371	2,258	2,071	2,027	1,764	1,881	1,719	1,701	1,547	1,850	2,012	
76	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
77	Demand Subtotal	2,247	2,371	2,258	2,071	2,027	1,764	1,881	1,719	1,701	1,547	1,850	2,012	2,371
78	Energy													
79	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
80	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
81	Hualapai Peach Springs Area	555,746	558,170	566,450	488,381	481,938	460,828	578,133	473,260	504,460	424,266	512,909	574,355	
82	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
83	Energy Subtotal	555,746	558,170	566,450	488,381	481,938	460,828	578,133	473,260	504,460	424,266	512,909	574,355	6,178,898
84														
85	Resource Vs. Load At Meter													
86	Capacity Excess/(Deficiency) {1}	-	-	-	-	-	259	142	304	322	462	159	-	462
87	Energy Excess/(Deficiency) {2}	42,594	7,452	110,878	219,626	260,606	280,597	140,107	205,486	118,484	180,150	57,310	17,909	1,641,200
88														
89	2009													
90	RESOURCES													
91	At CRSP Delivery													
92	CRSP Available Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
93	CRSP Available Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
94	WRP kWh	212,635	192,058	212,635	227,522	235,106	227,522	235,106	235,106	227,522	212,635	205,776	212,635	2,636,262
95	Aggregate kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
96	Renewable Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
97	Renewable Scheduled Capacity - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
98	Supplemental Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
99	Supplemental Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
100	Total Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
101	Total Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
102	At Meter													
103	CRSP AvailableCapacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
104	CRSP & WRP Available Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097
105	Renewable Scheduled Capacity - kW	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
106	Renewable Scheduled Capacity - kWh	197,470	203,546	276,458	309,876	331,142	343,294	306,838	267,344	224,812	203,546	182,280	191,394	3,038,000
107	Supplemental Capacity - kW	261	386	272	69	24	0	0	0	0	0	0	23	0
108	Supplemental Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
109	Total Capacity - kW	2,270	2,395	2,281	2,092	2,047	2,023	2,023	2,023	2,023	2,009	2,009	2,032	2,395
110	Total Energy -kWh	598,340	565,622	677,328	708,007	742,544	741,425	718,240	678,746	622,943	604,416	570,219	592,264	7,820,097
111														
112	Load At Meter													
113	Demand													
114	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
115	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
116	Hualapai Peach Springs Area	2,270	2,395	2,281	2,092	2,047	1,781	1,900	1,736	1,718	1,563	1,868	2,032	
117	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
118	Demand Subtotal	2,270	2,395	2,281	2,092	2,047	1,781	1,900	1,736	1,718	1,563	1,868	2,032	2,395
119	Energy													
120	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
121	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
122	Hualapai Peach Springs Area	561,304	563,752	572,114	493,265	486,758	465,436	583,915	477,993	509,504	428,509	518,038	580,099	
123	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
124	Energy Subtotal	561,304	563,752	572,114	493,265	486,758	465,436	583,915	477,993	509,504	428,509	518,038	580,099	6,240,687
125														
126	Resource Vs. Load At Meter													

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						RESOURCES VERSUS LOADS								
3		January	February	March	April	May	June	July	August	September	October	November	December	Total
4	CRSP Season	<<———— WINTER SEASON ————>>			<<———— SUMMER SEASON ————>>						<<———— WINTER SEASON ————>>			
5	Supplemental Season	<<———— WINTER SEASON ————>>				<<———— SUMMER SEASON ————>>						<<—— WINTER SEASON ——>>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
127	Capacity Excess/(Deficiency) {1}	-	-	-	-	-	242	123	287	305	446	141	-	446
128	Energy Excess/(Deficiency) {2}	37,037	1,870	105,214	214,742	255,787	275,989	134,326	200,753	113,439	175,907	52,181	12,165	1,579,411
129														
130	2010													
131	RESOURCES													
132	At CRSP Delivery													
133	CRSP Available Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
134	CRSP Available Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
135	WRP kWh	212,635	192,058	212,635	227,522	235,106	227,522	235,106	235,106	227,522	212,635	205,776	212,635	2,636,262
136	Aggregate kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
137	Renewable Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
138	Renewable Scheduled Capacity - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
139	Supplemental Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
140	Supplemental Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
141	Total Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
142	Total Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
143	At Meter													
144	CRSP AvailableCapacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
145	CRSP & WRP Available Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097
146	Renewable Scheduled Capacity - kW	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
147	Renewable Scheduled Capacity - kWh	197,470	203,546	276,458	309,876	331,142	343,294	306,838	267,344	224,812	203,546	182,280	191,394	3,038,000
148	Supplemental Capacity - kW	284	410	295	90	45	0	0	0	0	0	0	43	0
149	Supplemental Energy - kWh	0	3,767	0	0	0	0	0	0	0	0	0	0	0
150	Total Capacity - kW	2,292	2,418	2,303	2,113	2,068	2,023	2,023	2,023	2,023	2,009	2,009	2,052	2,418
151	Total Energy -kWh	598,340	569,389	677,328	708,007	742,544	741,425	718,240	678,746	622,943	604,416	570,219	592,264	7,823,864
152														
153	Load At Meter													
154	Demand													
155	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
156	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
157	Hualapai Peach Springs Area	2,292	2,418	2,303	2,113	2,068	1,799	1,919	1,753	1,735	1,578	1,887	2,052	
158	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
159	Demand Subtotal	2,292	2,418	2,303	2,113	2,068	1,799	1,919	1,753	1,735	1,578	1,887	2,052	2,418
160	Energy													
161	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
162	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
163	Hualapai Peach Springs Area	566,917	569,389	577,835	498,197	491,625	470,091	589,754	482,773	514,599	432,794	523,218	585,900	
164	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
165	Energy Subtotal	566,917	569,389	577,835	498,197	491,625	470,091	589,754	482,773	514,599	432,794	523,218	585,900	6,303,093
166														
167	Resource Vs. Load At Meter													
168	Capacity Excess/(Deficiency) {1}	-	-	-	-	-	224	104	270	288	431	122	-	431
169	Energy Excess/(Deficiency) {2}	31,424	-	99,493	209,810	250,919	271,335	128,486	195,973	108,344	171,622	47,001	6,364	1,520,771
170														
171	2011													
172	RESOURCES													
173	At CRSP Delivery													
174	CRSP Available Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
175	CRSP Available Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
176	WRP Available kWh	212,635	192,058	212,635	227,522	235,106	227,522	235,106	235,106	227,522	212,635	205,776	212,635	2,636,262
177	Aggregate kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
178	Renewable Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
179	Renewable Scheduled Capacity - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
180	Supplemental Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
181	Supplemental Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
182	Total Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
183	Total Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
184	At Meter													
185	CRSP AvailableCapacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
186	CRSP & WRP Available Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097

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	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						RESOURCES VERSUS LOADS								
3		January	February	March	April	May	June	July	August	September	October	November	December	Total
4	CRSP Season	<<———— WINTER SEASON ————>>			<<———— SUMMER SEASON ————>>						<<———— WINTER SEASON ————>>			
5	Supplemental Season	<<———— WINTER SEASON ————>>				<<———— SUMMER SEASON ————>>						<<—— WINTER SEASON ——>>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
187	Renewable Scheduled Capacity - kW	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
188	Renewable Scheduled Capacity - kWh	197,470	203,546	276,458	309,876	331,142	343,294	306,838	267,344	224,812	203,546	182,280	191,394	3,038,000
189	Supplemental Capacity - kW	307	434	318	111	65	0	0	0	0	0	0	64	0
190	Supplemental Energy - kWh	0	9,461	0	0	0	0	0	0	0	0	0	0	0
191	Total Capacity - kW	2,315	2,443	2,327	2,134	2,088	2,023	2,023	2,023	2,023	2,009	2,009	2,073	2,443
192	Total Energy -kWh	598,340	575,083	677,328	708,007	742,544	741,425	718,240	678,746	622,943	604,416	570,219	592,264	7,829,558
193														
194	**Load At Meter**													
195	**Demand**													
196	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
197	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
198	Hualapai Peach Springs Area	2,315	2,443	2,327	2,134	2,088	1,817	1,938	1,771	1,752	1,594	1,906	2,073	
199	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
200	**Demand Subtotal**	**2,315**	**2,443**	**2,327**	**2,134**	**2,088**	**1,817**	**1,938**	**1,771**	**1,752**	**1,594**	**1,906**	**2,073**	2,443
201	**Energy**													
202	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
203	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
204	Hualapai Peach Springs Area	572,586	575,083	583,614	503,179	496,542	474,792	595,651	487,601	519,745	437,122	528,451	591,759	
205	TBD	-	-	-	-	-	-	-	-	-	-	-	-	
206	**Energy Subtotal**	**572,586**	**575,083**	**583,614**	**503,179**	**496,542**	**474,792**	**595,651**	**487,601**	**519,745**	**437,122**	**528,451**	**591,759**	6,366,124
207														
208	**Resource Vs. Load At Meter**													
209	Capacity Excess/(Deficiency) {1}	-	-	-	-	-	206	85	252	271	415	103	-	415
210	Energy Excess/(Deficiency) {2}	25,755	-	93,714	204,828	246,003	266,634	122,589	191,146	103,198	167,294	41,768	505	1,463,434
211														
212	{1} Resource Minus Load (i.e., if Resources greater than Loads there is excess;													
213	if Resources less than Loads there is a deficiency)													
214														
215	{2} Resource Minus Load (i.e., if Resources greater than Loads there is excess;													
216	if Resources less than Loads there is a deficiency)													

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	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	CRSP Allocation	S	W		Hualapai									
2	CROD	625	609		CRSP SLCIP RESOURCES									
3	Energy	1,357,114	1,411,736											
4		January	February	March	April	May	June	July	August	September	October	November	December	Total
5		<<—— WINTER SEASON ——>>			<<—— SUMMER SEASON ——>>						<<—— WINTER SEASON ——>>			
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
7	P Max Capacity At CRSP Delviery - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
8	2007													
9	CRSP AT CRSP Delivery													
10	Escalation Rate - %	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
11	Max Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
12	Scheduled Capacity	609	609	609	625	625	625	625	625	625	609	609	609	625
13	Capacity $/kW/Month	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12	4.12	
14	Scheduled Capacity Cost	$ 2,509.57	$ 2,509.57	$ 2,509.57	$ 2,575.50	$ 2,575.50	$ 2,575.50	$ 2,575.50	$ 2,575.50	$ 2,575.50	$ 2,509.57	$ 2,509.57	$ 2,509.57	$ 30,510.40
15	Parker-Davis Transmission Cost - $/kW	$ 1.10	$ 1.10	$ 1.10	$ 1.10	$ 1.10	$ 1.10	$ 1.10	$ 1.10	$ 1.10	$ 1.10	$ 1.10	$ 1.10	
16	Parker-Davis Transmission Cost - $	$ 670.87	$ 670.87	$ 670.87	$ 688.50	$ 688.50	$ 688.50	$ 688.50	$ 688.50	$ 688.50	$ 670.87	$ 670.87	$ 670.87	$ 8,156.25
17	Max Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
18	Scheduled Energy - kWh	240,461	217,190	240,461	169,554	138,510	99,667	229,894	227,447	222,478	240,461	232,704	240,461	2,499,285
19	Energy $/kWh	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	
20	Scheduled Energy Cost	$ 2,330.06	$ 2,104.57	$ 2,330.06	$ 1,642.98	$ 1,342.16	$ 965.77	$ 2,227.67	$ 2,203.96	$ 2,155.81	$ 2,330.06	$ 2,254.90	$ 2,330.06	$ 24,218.07
21	Load Factor - %	53.1%	53.1%	53.1%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	53.1%	53.1%	53.1%	50.6%
22	Total CRSP Cost	$ 5,510.50	$ 5,285.01	$ 5,510.50	$ 4,906.98	$ 4,606.16	$ 4,229.77	$ 5,491.67	$ 5,467.96	$ 5,419.81	$ 5,510.50	$ 5,435.34	$ 5,510.50	$ 62,884.72
23	Average CRSP Cost - kWh	$ 22.92	$ 24.33	$ 22.92	$ 28.94	$ 33.26	$ 42.44	$ 23.89	$ 24.04	$ 24.36	$ 22.92	$ 23.36	$ 22.92	
24	WRP Energy - kWh	127,064	146,191	50,485	-	-	-	70,276	-	87,957	4,267	135,260	185,965	807,468
25	WRP - $/MWH	50	50	50	50	50	50	50	50	50	50	50	50	
26	WRP Cost	$ 6,353.22	$ 7,309.54	$ 2,524.27	$ -	$ -	$ -	$ 3,513.82	$ -	$ 4,397.86	$ 213.37	$ 6,763.01	$ 9,298.27	$ 40,373.38
27	Total CRSP Plus WRP Cost	$ 11,863.73	$ 12,594.56	$ 8,034.78	$ 4,906.98	$ 4,606.16	$ 4,229.77	$ 9,005.49	$ 5,467.96	$ 9,817.67	$ 5,723.88	$ 12,198.35	$ 14,808.78	$ 103,258.11
28	Total Max Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
29	Scheduled Energy - kWh	367,525	363,381	290,946	169,554	138,510	99,667	300,170	227,447	310,435	244,728	367,964	426,426	3,306,753
30	Aggregate Scheduled Load Factor	81.1%	88.8%	64.2%	37.7%	29.8%	22.1%	64.6%	48.9%	69.0%	54.0%	83.9%	94.1%	60.4%
31	eduled Aggregate Average Cost $/MWH	$ 32.28	$ 34.66	$ 27.62	$ 28.94	$ 33.26	$ 42.44	$ 30.00	$ 24.04	$ 31.63	$ 23.39	$ 33.15	$ 34.73	$ 31.23
32														
33	CRSP At Delivery													
34	Max Capacity - kW	585	585	585	600	600	600	600	600	600	585	585	585	600
35	Max Energy - kWh	434,972	392,878	434,972	432,000	446,400	432,000	446,400	446,400	432,000	434,972	420,941	434,972	5,188,908
36	Scheduled Capacity - kW	585	585	585	600	600	600	600	600	600	585	585	585	
37	Scheduled Energy - kWh	352,824	348,846	279,309	162,772	132,970	95,680	288,163	218,349	298,018	234,939	353,245	409,369	
38	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
39														
40	CRSP At Nelson													
41	Max Capacity - kW	561	561	561	576	576	576	576	576	576	561	561	561	
42	Max Energy - kWh	417,573	377,163	417,573	414,720	428,544	414,720	428,544	428,544	414,720	417,573	404,103	417,573	
43	Scheduled Capacity - kW	561	561	561	576	576	576	576	576	576	561	561	561	
44	Scheduled Energy - kWh	338,711	334,892	268,136	156,261	127,651	91,853	276,637	209,615	286,097	225,541	339,115	392,995	
45	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
46														
47	CRSP At Customer Meter													
48	Max Capacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
49	Scheduled Capacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
50	Max Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097
51	Scheduled Energy - kWh	325,163	321,496	257,411	150,010	122,545	88,179	265,571	201,231	274,653	216,520	325,551	377,275	2,925,604
52	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
53	Scheduled Average Cost $/MWH	$ 36.49	$ 39.17	$ 31.21	$ 32.71	$ 37.59	$ 47.97	$ 33.91	$ 27.17	$ 35.75	$ 26.44	$ 37.47	$ 39.25	$ 35.29
54														
55	2008													
56	CRSP AT CRSP Delivery													
57	Escalation Rate - %	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
58	Max Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
59	Scheduled Capacity	609	609	609	625	625	625	625	625	625	609	609	609	625
60	Capacity $/kW/Month	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	
61	Scheduled Capacity Cost	$ 2,559.76	$ 2,559.76	$ 2,559.76	$ 2,627.01	$ 2,627.01	$ 2,627.01	$ 2,627.01	$ 2,627.01	$ 2,627.01	$ 2,559.76	$ 2,559.76	$ 2,559.76	$ 31,120.61
62	Parker-Davis Transmission Cost - $/kW	$ 1.12	$ 1.12	$ 1.12	$ 1.12	$ 1.12	$ 1.12	$ 1.12	$ 1.12	$ 1.12	$ 1.12	$ 1.12	$ 1.12	
63	Parker-Davis Transmission Cost - $	$ 684.29	$ 684.29	$ 684.29	$ 702.27	$ 702.27	$ 702.27	$ 702.27	$ 702.27	$ 702.27	$ 684.29	$ 684.29	$ 684.29	$ 8,319.37
64	Max Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
65	Scheduled Energy - kWh	240,461	217,190	240,461	201,761	170,442	132,846	229,894	229,894	222,478	240,461	232,704	240,461	2,599,050
66	Energy $/kWh	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	
67	Scheduled Energy Cost	$ 2,376.66	$ 2,146.66	$ 2,376.66	$ 1,994.17	$ 1,684.61	$ 1,313.02	$ 2,272.22	$ 2,272.22	$ 2,198.93	$ 2,376.66	$ 2,300.00	$ 2,376.66	$ 25,688.49
68	Load Factor - %	53.1%	53.1%	53.1%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	53.1%	53.1%	53.1%	50.6%
69	Total CRSP Cost	$ 5,620.71	$ 5,390.71	$ 5,620.71	$ 5,323.45	$ 5,013.89	$ 4,642.30	$ 5,601.50	$ 5,601.50	$ 5,528.21	$ 5,620.71	$ 5,544.05	$ 5,620.71	$ 65,128.47
70	Average CRSP Cost - kWh	$ 23.37	$ 24.82	$ 23.37	$ 26.38	$ 29.42	$ 34.94	$ 24.37	$ 24.37	$ 24.85	$ 23.37	$ 23.82	$ 23.37	

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	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	CRSP Allocation	S	W		Hualapai									
2	CROD	625	609		CRSP SLCIP RESOURCES									
3	Energy	1,357,114	1,411,736											
4		January	February	March	April	May	June	July	August	September	October	November	December	Total
5		<<——— WINTER SEASON ———>>			<<——— SUMMER SEASON ———>>						<<——— WINTER SEASON ———>>			
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
71	WRP Energy - kWh	164,491	183,635	87,311	-	-	-	76,746	2,849	93,602	9,015	141,000	192,393	951,045
72	WRP - $/MWH	50	50	50	50	50	50	50	50	50	50	50	50	
73	WRP Cost	$ 8,224.57	$ 9,181.74	$ 4,365.57	$ -	$ -	$ -	$ 3,837.32	$ 142.47	$ 4,680.11	$ 450.77	$ 7,050.01	$ 9,619.67	$ 47,552.25
74	Total CRSP Plus WRP Cost	$ 13,845.29	$ 14,572.46	$ 9,986.29	$ 5,323.45	$ 5,013.89	$ 4,642.30	$ 9,438.82	$ 5,743.97	$ 10,208.32	$ 6,071.49	$ 12,594.06	$ 15,240.39	$ 112,680.72
75	Total Max Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
76	Scheduled Energy - kWh	404,952	400,825	327,772	201,761	170,442	132,846	306,640	232,743	316,080	249,476	373,704	432,854	3,550,095
77	Aggregate Scheduled Load Factor	89.4%	97.9%	72.3%	44.8%	36.7%	29.5%	65.9%	50.1%	70.2%	55.1%	85.2%	95.5%	64.8%
78	eduled Aggregate Average Cost $/MWH	$ 34.19	$ 36.36	$ 30.47	$ 26.38	$ 29.42	$ 34.94	$ 30.78	$ 24.68	$ 32.30	$ 24.34	$ 33.70	$ 35.21	$ 31.74
79														
80	CRSP At Delivery													
81	Max Capacity - kW	585	585	585	600	600	600	600	600	600	585	585	585	600
82	Max Energy - kWh	434,972	392,878	434,972	432,000	446,400	432,000	446,400	446,400	432,000	434,972	420,941	434,972	5,188,908
83	Scheduled Capacity - kW	585	585	585	600	600	600	600	600	600	585	585	585	
84	Scheduled Energy - kWh	388,754	384,792	314,661	193,690	163,624	127,533	294,374	223,434	303,437	239,497	358,755	415,540	
85	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
86														
87	CRSP At Nelson													
88	Max Capacity - kW	561	561	561	576	576	576	576	576	576	561	561	561	
89	Max Energy - kWh	417,573	377,163	417,573	414,720	428,544	414,720	428,544	428,544	414,720	417,573	404,103	417,573	
90	Scheduled Capacity - kW	561	561	561	576	576	576	576	576	576	561	561	561	
91	Scheduled Energy - kWh	373,204	369,400	302,075	185,943	157,079	122,431	282,599	214,496	291,300	229,917	344,405	398,918	
92	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
93														
94	CRSP At Customer Meter													
95	Max Capacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
96	Scheduled Capacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
97	Max Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097
98	Scheduled Energy - kWh	358,276	354,624	289,992	178,505	150,796	117,534	271,295	205,916	279,648	220,720	330,629	382,961	3,140,898
99	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
100	Scheduled Average Cost $/MWH	$ 38.64	$ 41.09	$ 34.44	$ 29.82	$ 33.25	$ 39.50	$ 34.79	$ 27.89	$ 36.50	$ 27.51	$ 38.09	$ 39.80	$ 35.88
101														
102	2009													
103	CRSP AT CRSP Delivery													
104	Escalation Rate - %	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
105	Max Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
106	Scheduled Capacity	609	609	609	625	625	625	625	625	625	609	609	609	625
107	Capacity $/kW/Month	4.29	4.29	4.29	4.29	4.29	4.29	4.29	4.29	4.29	4.29	4.29	4.29	
108	Scheduled Capacity Cost	$ 2,610.95	$ 2,610.95	$ 2,610.95	$ 2,679.55	$ 2,679.55	$ 2,679.55	$ 2,679.55	$ 2,679.55	$ 2,679.55	$ 2,610.95	$ 2,610.95	$ 2,610.95	$ 31,743.02
109	Parker-Davis Transmission Cost - $/kW	$ 1.15	$ 1.15	$ 1.15	$ 1.15	$ 1.15	$ 1.15	$ 1.15	$ 1.15	$ 1.15	$ 1.15	$ 1.15	$ 1.15	
110	- Parker-Davis Transmission Cost - $	$ 697.98	$ 697.98	$ 697.98	$ 716.32	$ 716.32	$ 716.32	$ 716.32	$ 716.32	$ 716.32	$ 697.98	$ 697.98	$ 697.98	$ 8,485.76
111	Max Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
112	Scheduled Energy - kWh	240,461	217,190	240,461	207,281	175,889	138,055	229,894	229,894	222,478	240,461	232,704	240,461	2,615,226
113	Energy $/kWh	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	
114	Scheduled Energy Cost	$ 2,424.20	$ 2,189.60	$ 2,424.20	$ 2,089.70	$ 1,773.22	$ 1,391.80	$ 2,317.67	$ 2,317.67	$ 2,242.90	$ 2,424.20	$ 2,346.00	$ 2,424.20	$ 26,365.34
115	Load Factor - %	53.1%	53.1%	53.1%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	53.1%	53.1%	53.1%	50.6%
116	Total CRSP Cost	$ 5,733.13	$ 5,498.53	$ 5,733.13	$ 5,485.56	$ 5,169.09	$ 4,787.66	$ 5,713.53	$ 5,713.53	$ 5,638.77	$ 5,733.13	$ 5,654.93	$ 5,733.13	$ 66,594.12
117	Average CRSP Cost - kWh	$ 23.84	$ 25.32	$ 23.84	$ 26.46	$ 29.39	$ 34.68	$ 24.85	$ 24.85	$ 25.35	$ 23.84	$ 24.30	$ 23.84	
118	WRP Energy - kWh	170,773	189,944	93,714	-	-	-	83,280	8,198	99,304	13,810	146,797	198,885	1,004,708
119	WRP - $/MWH	50	50	50	50	50	50	50	50	50	50	50	50	
120	WRP Cost	$ 8,538.67	$ 9,497.19	$ 4,685.72	$ -	$ -	$ -	$ 4,164.02	$ 409.92	$ 4,965.21	$ 690.52	$ 7,339.86	$ 9,944.27	$ 50,235.40
121	Total CRSP Plus WRP Cost	$ 14,271.80	$ 14,995.72	$ 10,418.85	$ 5,485.56	$ 5,169.09	$ 4,787.66	$ 9,877.55	$ 6,123.45	$ 10,603.98	$ 6,423.65	$ 12,994.79	$ 15,677.40	$ 116,829.52
122	Total Max Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
123	Scheduled Energy - kWh	411,234	407,134	334,175	207,281	175,889	138,055	313,174	238,092	321,782	254,271	379,501	439,346	3,619,934
124	Aggregate Scheduled Load Factor	90.8%	99.5%	73.8%	46.1%	37.8%	30.7%	67.3%	51.2%	71.5%	56.1%	86.5%	97.0%	66.1%
125	eduled Aggregate Average Cost $/MWH	$ 34.70	$ 36.83	$ 31.18	$ 26.46	$ 29.39	$ 34.68	$ 31.54	$ 25.72	$ 32.95	$ 25.26	$ 34.24	$ 35.68	$ 32.27
126														
127	CRSP At Delivery													
128	Max Capacity - kW	585	585	585	600	600	600	600	600	600	585	585	585	600
129	Max Energy - kWh	434,972	392,878	434,972	432,000	446,400	432,000	446,400	446,400	432,000	434,972	420,941	434,972	5,188,908
130	Scheduled Capacity - kW	585	585	585	600	600	600	600	600	600	585	585	585	
131	Scheduled Energy - kWh	394,785	390,848	320,808	198,990	168,854	132,533	300,647	228,569	308,911	244,100	364,321	421,772	
132	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
133														
134	CRSP At Nelson													

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	CRSP Allocation	S	W		Hualapai									
2	CROD	625	609		CRSP SLCIP RESOURCES									
3	Energy	1,357,114	1,411,736											
4		January	February	March	April	May	June	July	August	September	October	November	December	Total
5		<<—— WINTER SEASON ——>>			<<—— SUMMER SEASON ——>>						<<—— WINTER SEASON ——>>			
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
135	Max Capacity - kW	561	561	561	576	576	576	576	576	576	561	561	561	
136	Max Energy - kWh	417,573	377,163	417,573	414,720	428,544	414,720	428,544	428,544	414,720	417,573	404,103	417,573	
137	Scheduled Capacity - kW	561	561	561	576	576	576	576	576	576	561	561	561	
138	Scheduled Energy - kWh	378,993	375,215	307,975	191,030	162,100	127,232	288,622	219,426	296,554	234,336	349,748	404,901	
139	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
140														
141	CRSP At Customer Meter													
142	Max Capacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
143	Scheduled Capacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
144	Max Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097
145	Scheduled Energy - kWh	363,834	360,206	295,656	183,389	155,616	122,142	277,077	210,649	284,692	224,963	335,758	388,705	3,202,687
146	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
147	Scheduled Average Cost $/MWH	$ 39.23	$ 41.63	$ 35.24	$ 29.91	$ 33.22	$ 39.20	$ 35.65	$ 29.07	$ 37.25	$ 28.55	$ 38.70	$ 40.33	$ 36.48
148														
149	2010													
150	CRSP AT CRSP Delivery													
151	Escalation Rate - %	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
152	Max Capacity - kW	609	609	609	625	625	625	625	625	626	609	609	609	625
153	Scheduled Capacity	609	609	609	625	625	625	625	625	625	609	609	609	625
154	Capacity $/kW/Month	4.37	4.37	4.37	4.37	4.37	4.37	4.37	4.37	4.37	4.37	4.37	4.37	
155	Scheduled Capacity Cost	$ 2,663.17	$ 2,663.17	$ 2,663.17	$ 2,733.14	$ 2,733.14	$ 2,733.14	$ 2,733.14	$ 2,733.14	$ 2,733.14	$ 2,663.17	$ 2,663.17	$ 2,663.17	$ 32,377.88
156	Parker-Davis Transmission Cost - $/kW	$ 1.17	$ 1.17	$ 1.17	$ 1.17	$ 1.17	$ 1.17	$ 1.17	$ 1.17	$ 1.17	$ 1.17	$ 1.17	$ 1.17	
157	Parker-Davis Transmission Cost - $	$ 711.94	$ 711.94	$ 711.94	$ 730.64	$ 730.64	$ 730.64	$ 730.64	$ 730.64	$ 730.64	$ 711.94	$ 711.94	$ 711.94	$ 8,655.47
158	Max Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
159	Scheduled Energy - kWh	240,461	217,190	240,461	212,856	181,391	143,316	229,894	229,894	222,478	240,461	232,704	240,461	2,631,564
160	Energy $/kWh	0.0103	0.0103	0.0103	0.0103	0.0103	0.0103	0.0103	0.0103	0.0103	0.0103	0.0103	0.0103	
161	Scheduled Energy Cost	$ 2,472.68	$ 2,233.39	$ 2,472.68	$ 2,188.82	$ 1,865.26	$ 1,473.73	$ 2,364.02	$ 2,364.02	$ 2,287.76	$ 2,472.68	$ 2,392.92	$ 2,472.68	$ 27,060.65
162	Load Factor - %	53.1%	53.1%	53.1%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	53.1%	53.1%	53.1%	50.6%
163	Total CRSP Cost	$ 5,847.79	$ 5,608.50	$ 5,847.79	$ 5,652.60	$ 5,329.05	$ 4,937.52	$ 5,827.80	$ 5,827.80	$ 5,751.54	$ 5,847.79	$ 5,768.03	$ 5,847.79	$ 68,094.01
164	Average CRSP Cost - kWh	$ 24.32	$ 25.82	$ 24.32	$ 26.56	$ 29.38	$ 34.45	$ 25.35	$ 25.35	$ 25.85	$ 24.32	$ 24.79	$ 24.32	
165	WRP Energy - kWh	177,117	192,058	100,180	-	-	-	89,880	13,601	105,063	18,654	152,652	205,442	1,054,650
166	WRP - $/MWH	50	50	50	50	50	50	50	50	50	50	50	50	
167	WRP Cost	$ 8,855.87	$ 9,602.89	$ 5,009.02	$ -	$ -	$ -	$ 4,494.02	$ 680.07	$ 5,253.16	$ 932.72	$ 7,632.61	$ 10,272.12	$ 52,732.50
168	Total CRSP Plus WRP Cost	$ 14,703.66	$ 15,211.39	$ 10,856.81	$ 5,652.60	$ 5,329.05	$ 4,937.52	$ 10,321.82	$ 6,507.87	$ 11,004.71	$ 6,780.51	$ 13,400.64	$ 16,119.91	$ 120,826.51
169	Total Max Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
170	Scheduled Energy - kWh	417,578	409,248	340,641	212,856	181,391	143,316	319,774	243,495	327,541	259,115	385,356	445,903	3,686,214
171	Aggregate Scheduled Load Factor	92.2%	100.0%	75.2%	47.3%	39.0%	31.8%	68.8%	52.4%	72.8%	57.2%	87.9%	98.4%	67.3%
172	duled Aggregate Average Cost $/MWH	$ 35.21	$ 37.17	$ 31.87	$ 26.56	$ 29.38	$ 34.45	$ 32.28	$ 26.73	$ 33.60	$ 26.17	$ 34.77	$ 36.15	$ 32.78
173														
174	CRSP At Delivery													
175	Max Capacity - kW	585	585	585	600	600	600	600	600	600	585	585	585	600
176	Max Energy - kWh	434,972	392,878	434,972	432,000	446,400	432,000	446,400	446,400	432,000	434,972	420,941	434,972	5,188,908
177	Scheduled Capacity - kW	585	585	585	600	600	600	600	600	600	585	585	585	
178	Scheduled Energy - kWh	400,875	392,878	327,016	204,342	174,135	137,583	306,983	233,755	314,439	248,750	369,942	428,066	
179	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
180														
181	CRSP At Nelson													
182	Max Capacity - kW	561	561	561	576	576	576	576	576	576	561	561	561	
183	Max Energy - kWh	417,573	377,163	417,573	414,720	428,544	414,720	428,544	428,544	414,720	417,573	404,103	417,573	
184	Scheduled Capacity - kW	561	561	561	576	576	576	576	576	576	561	561	561	
185	Scheduled Energy - kWh	384,840	377,163	313,935	196,168	167,170	132,080	294,704	224,405	301,862	238,800	355,144	410,944	
186	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
187														
188	CRSP At Customer Meter													
189	Max Capacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
190	Scheduled Capacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
191	Max Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097
192	Scheduled Energy - kWh	369,447	362,076	301,377	188,321	160,483	126,797	282,916	215,429	289,787	229,248	340,938	394,506	3,261,326
193	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
194	Scheduled Average Cost $/MWH	$ 39.80	$ 42.01	$ 36.02	$ 30.02	$ 33.21	$ 38.94	$ 36.48	$ 30.21	$ 37.98	$ 29.58	$ 39.31	$ 40.86	$ 37.05
195														
196	2011													
197	CRSP AT CRSP Delivery													
198	Escalation Rate - %	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	CRSP Allocation	S	W		Hualapai									
2	CROD	625	609		CRSP SLCIP RESOURCES									
3	Energy	1,357,114	1,411,736											
4		January	February	March	April	May	June	July	August	September	October	November	December	Total
5		<<———— WINTER SEASON ————>>			<<———— SUMMER SEASON ————>>						<<———— WINTER SEASON ————>>			
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
199	Max Capacity - kW	609	609	609	625	625	625	625	625	625	609	609	609	625
200	Scheduled Capacity	609	609	609	625	625	625	625	625	625	609	609	609	625
201	Capacity $/kW/Month	4.46	4.46	4.46	4.46	4.46	4.46	4.46	4.46	4.46	4.46	4.46	4.46	
202	Scheduled Capacity Cost	$ 2,716.44	$ 2,716.44	$ 2,716.44	$ 2,787.80	$ 2,787.80	$ 2,787.80	$ 2,787.80	$ 2,787.80	$ 2,787.80	$ 2,716.44	$ 2,716.44	$ 2,716.44	$ 33,025.44
203	Parker-Davis Transmission Cost - $/kW	$ 1.19	$ 1.19	$ 1.19	$ 1.19	$ 1.19	$ 1.19	$ 1.19	$ 1.19	$ 1.19	$ 1.19	$ 1.19	$ 1.19	
204	Parker-Davis Transmission Cost - $	$ 726.18	$ 726.18	$ 726.18	$ 745.25	$ 745.25	$ 745.25	$ 745.25	$ 745.25	$ 745.25	$ 726.18	$ 726.18	$ 726.18	$ 8,828.58
205	Max Energy - kWh	240,461	217,190	240,461	222,478	229,894	222,478	229,894	229,894	222,478	240,461	232,704	240,461	2,768,850
206	Scheduled Energy - kWh	240,461	217,190	240,461	218,487	186,948	148,629	229,894	229,894	222,478	240,461	232,704	240,461	2,648,065
207	Energy $/kWh	0.0105	0.0105	0.0105	0.0105	0.0105	0.0105	0.0105	0.0105	0.0105	0.0105	0.0105	0.0105	
208	Scheduled Energy Cost	$ 2,522.13	$ 2,278.06	$ 2,522.13	$ 2,291.66	$ 1,960.85	$ 1,558.94	$ 2,411.30	$ 2,411.30	$ 2,333.52	$ 2,522.13	$ 2,440.78	$ 2,522.13	$ 27,774.94
209	Load Factor - %	53.1%	53.1%	53.1%	49.4%	49.4%	49.4%	49.4%	49.4%	49.4%	53.1%	53.1%	53.1%	50.6%
210	Total CRSP Cost	$ 5,964.75	$ 5,720.67	$ 5,964.75	$ 5,824.72	$ 5,493.91	$ 5,091.99	$ 5,944.36	$ 5,944.36	$ 5,866.58	$ 5,964.75	$ 5,883.39	$ 5,964.75	$ 69,628.96
211	Average CRSP Cost - kWh	$ 24.81	$ 26.34	$ 24.81	$ 26.66	$ 29.39	$ 34.26	$ 25.86	$ 25.86	$ 26.37	$ 24.81	$ 25.28	$ 24.81	
212	WRP Energy - kWh	183,525	192,058	106,711	-	-	-	96,546	19,058	110,879	23,545	158,566	212,064	1,102,955
213	WRP - $/MWH	50	50	50	50	50	50	50	50	50	50	50	50	
214	WRP Cost	$ 9,176.27	$ 9,602.89	$ 5,335.57	$ -	$ -	$ -	$ 4,827.32	$ 952.92	$ 5,543.96	$ 1,177.27	$ 7,928.31	$ 10,603.22	$ 55,147.75
215	Total CRSP Plus WRP Cost	$ 15,141.02	$ 15,323.56	$ 11,300.32	$ 5,824.72	$ 5,493.91	$ 5,091.99	$ 10,771.68	$ 6,897.28	$ 11,410.54	$ 7,142.02	$ 13,811.70	$ 16,567.97	$ 124,776.72
216	Total Max Energy - kWh	453,096	409,248	453,096	450,000	465,000	450,000	465,000	465,000	450,000	453,096	438,480	453,096	5,405,112
217	Scheduled Energy - kWh	423,986	409,248	347,172	218,487	186,948	148,629	326,440	248,952	333,357	264,006	391,270	452,525	3,751,020
218	Aggregate Scheduled Load Factor	93.6%	100.0%	76.6%	48.6%	40.2%	33.0%	70.2%	53.5%	74.1%	58.3%	89.2%	99.9%	68.5%
219	eduled Aggregate Average Cost $/MWH	$ 35.71	$ 37.44	$ 32.55	$ 26.66	$ 29.39	$ 34.26	$ 33.00	$ 27.71	$ 34.23	$ 27.05	$ 35.30	$ 36.61	$ 33.26
220														
221	**CRSP At Delivery**													
222	Max Capacity - kW	585	585	585	600	600	600	600	600	600	585	585	585	600
223	Max Energy - kWh	434,972	392,878	434,972	432,000	446,400	432,000	446,400	446,400	432,000	434,972	420,941	434,972	5,188,908
224	Scheduled Capacity - kW	585	585	585	600	600	600	600	600	600	585	585	585	
225	Scheduled Energy - kWh	407,027	392,878	333,285	209,748	179,470	142,684	313,383	238,994	320,023	253,446	375,619	434,424	
226	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
227														
228	**CRSP At Nelson**													
229	Max Capacity - kW	561	561	561	576	576	576	576	576	576	561	561	561	
230	Max Energy - kWh	417,573	377,163	417,573	414,720	428,544	414,720	428,544	428,544	414,720	417,573	404,103	417,573	
231	Scheduled Capacity - kW	561	561	561	576	576	576	576	576	576	561	561	561	
232	Scheduled Energy - kWh	390,746	377,163	319,954	201,358	172,291	136,977	300,847	229,434	307,222	243,308	360,594	417,047	
233	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
234			584.64	561.2544	538.804224									
235	**CRSP At Customer Meter**													
236	Max Capacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
237	Scheduled Capacity - kW	539	539	539	553	553	553	553	553	553	539	539	539	553
238	Max Energy - kWh	400,870	362,076	400,870	398,131	411,402	398,131	411,402	411,402	398,131	400,870	387,939	400,870	4,782,097
239	Scheduled Energy - kWh	375,116	362,076	307,156	193,303	165,400	131,498	288,813	220,257	294,933	233,576	346,171	400,365	3,318,663
240	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
241	Scheduled Average Cost $/MWH	$ 40.36	$ 42.32	$ 36.79	$ 30.13	$ 33.22	$ 38.72	$ 37.30	$ 31.31	$ 38.69	$ 30.58	$ 39.90	$ 41.38	$ 37.60
242		$ 16,180.57	$ 15,323.56	$ 14,748.09	$ 11,996.69	$ 13,665.14	$ 15,416.88	$ 15,343.79	$ 12,882.95	$ 15,403.12	$ 12,257.35	$ 15,478.20	$ 16,588.88	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						Supplemental RESOURCES								
3														
4		January	February	March	April	May	June	July	August	September	October	November	December	Total
5		<<—— WINTER SEASON ——>>				<<—— SUMMER SEASON ——>>						<<—— WINTER SEASON ——>>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
7	Year	2,007	2,008	2,009	2,010	2,011								
8	Purchased Power Escalation Rate - %	0.0%	2.0%	2.0%	2.0%	2.0%								
9														
10	2007													
11	Supplemental At CRSP													
12	Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Load Factor - %	-	-	-	-	-	-	-	-	-	-	-	-	-
15														
16	Supplemental At Transmission													
17	Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
18	Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
19	Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
20														
21	Supplemental At Nelson													
22	Capacity - kW	0	64	0	0	0	0	0	0	0	0	0	0	
23	Capacity $/kW/Month	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	
24	Capacity Cost	$ -	$ 128.54	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
25	Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	
26	Energy $/kWh	0.0650	0.0650	0.0650	0.0650	0.0650	0.0650	0.0650	0.0650	0.0650	0.0650	0.0650	0.0650	
27	Energy Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
28	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
29	Total Supplemental Cost	$ -	$ 129	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30														
31	Supplemental At Customer Meter													
32	Capacity - kW	0	62	0	0	0	0	0	0	0	0	0	0	
33	Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
35	Average Cost $/MWH	-	-	-	-	-	-	-	-	-	-	-	-	
36														
37	2008													
38	Supplemental At CRSP													
39	Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
41	Load Factor - %	-	-	-	-	-	-	-	-	-	-	-	-	-
42														
43	Supplemental At Transmission													
44	Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
45	Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
46	Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
47														
48	Supplemental At Nelson													
49	Capacity - kW	248	377	260	50	4	0	0	0	0	0	0	3	
50	Capacity $/kW/Month	2.04	2.04	2.04	2.04	2.04	2.04	2.04	2.04	2.04	2.04	2.04	2.04	
51	Capacity Cost	$ 506.81	$ 769.25	$ 529.73	$ 102.76	$ 8.51	$ -	$ -	$ -	$ -	$ -	$ -	$ 6.09	$ 1,923.15
52	Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	
53	Energy $/kWh	0.0663	0.0663	0.0663	0.0663	0.0663	0.0663	0.0663	0.0663	0.0663	0.0663	0.0663	0.0663	
54	Energy Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
56	Total Supplemental Cost	$ 507	$ 769	$ 530	$ 103	$ 9	$ -	$ -	$ -	$ -	$ -	$ -	$ 6	$ 1,923.15
57														
58	Supplemental At Customer Meter													
59	Capacity - kW	238	362	249	48	4	0	0	0	0	0	0	3	
60	Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
61	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
62	Average Cost $/MWH	-	-	-	-	-	-	-	-	-	-	-	-	
63														
64	2009													
65	Supplemental At CRSP													
66	Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
67	Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
68	Load Factor - %	-	-	-	-	-	-	-	-	-	-	-	-	-
69														
70	Supplemental At Transmission													

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	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						Supplemental RESOURCES								
3														
4		January	February	March	April	May	June	July	August	September	October	November	December	Total
5		<<————— WINTER SEASON —————>>				<<————— SUMMER SEASON —————>>						<<—— WINTER SEASON ——>>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
71	Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
72	Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
73	Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
74														
75	**Supplemental At Nelson**													
76	Capacity - kW	272	402	283	72	25	0	0	0	0	0	0	24	
77	Capacity $/kW/Month	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	
78	Capacity Cost	$ 565.66	$ 836.02	$ 589.27	$ 149.71	$ 52.61	$ -	$ -	$ -	$ -	$ -	$ -	$ 49.81	$ 2,243.09
79	Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	
80	Energy $/kWh	0.0676	0.0676	0.0676	0.0676	0.0676	0.0676	0.0676	0.0676	0.0676	0.0676	0.0676	0.0676	
81	Energy Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
83	Total Supplemental Cost	$ 566	$ 836	$ 589	$ 150	$ 53	$ -	$ -	$ -	$ -	$ -	$ -	$ 50	$ 2,243.09
84														
85	**Supplemental At Customer Meter**													
86	Capacity - kW	261	386	272	69	24	0	0	0	0	0	0	23	
87	Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
88	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
89	Average Cost $/MWH	-	-	-	-	-	-	-	-	-	-	-	-	
90														
91	**2010**													
92	**Supplemental At CRSP**													
93	Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
94	Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
95	Energy $/kWh	-	-	-	-	-	-	-	-	-	-	-	-	
96														
97	**Supplemental At Transmission**													
98	Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
99	Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
100	Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
101														
102	**Supplemental At Nelson**													
103	Capacity - kW	295	427	307	94	47	0	0	0	0	0	0	45	
104	Capacity $/kW/Month	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	2.12	
105	Capacity Cost	$ 627.15	$ 905.68	$ 651.48	$ 198.96	$ 98.92	$ -	$ -	$ -	$ -	$ -	$ -	$ 95.73	$ 2,577.93
106	Energy - kWh	0	3,924	0	0	0	0	0	0	0	0	0	0	
107	Energy $/kWh	0.0690	0.0690	0.0690	0.0690	0.0690	0.0690	0.0690	0.0690	0.0690	0.0690	0.0690	0.0690	
108	Energy Cost	$ -	$ 271	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 270.67
109	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
110	Total Supplemental Cost	$ 627	$ 1,176	$ 651	$ 199	$ 99	$ -	$ -	$ -	$ -	$ -	$ -	$ 96	$ 2,848.60
111														
112	**Supplemental At Customer Meter**													
113	Capacity - kW	284	410	295	90	45	0	0	0	0	0	0	43	
114	Energy - kWh	0	3,767	0	0	0	0	0	0	0	0	0	0	3,767
115	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
116	Average Cost $/MWH	-	$ 312.28	-	-	-	-	-	-	-	-	-	-	
117														
118	**2011**													
119	**Supplemental At CRSP**													
120	Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
121	Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
122	Load Factor - %	-	-	-	-	-	-	-	-	-	-	-	-	-
123														
124	**Supplemental At Transmission**													
125	Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
126	Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
127	Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
128														
129	**Supplemental At Nelson**													
130	Capacity - kW	319	452	331	116	68	0	0	0	0	0	0	66	
131	Capacity $/kW/Month	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	
132	Capacity Cost	$ 691.39	$ 978.34	$ 716.45	$ 250.59	$ 147.53	$ -	$ -	$ -	$ -	$ -	$ -	$ 143.92	$ 2,928.22
133	Energy - kWh	0	9,855	0	0	0	0	0	0	0	0	0	0	
134	Energy $/kWh	0.0704	0.0704	0.0704	0.0704	0.0704	0.0704	0.0704	0.0704	0.0704	0.0704	0.0704	0.0704	

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	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						Supplemental RESOURCES								
3														
4		January	February	March	April	May	June	July	August	September	October	November	December	Total
5		<<------------ WINTER SEASON ------------>>				<<------------ SUMMER SEASON ------------>>						<<------ WINTER SEASON ------>>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
135	Energy Cost	$ -	$ 693	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 693.39
136	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
137	Total Supplemental Cost	$ 691	$ 1,672	$ 716	$ 251	$ 148	$ -	$ -	$ -	$ -	$ -	$ -	$ 144	$ 3,621.61
138														
139	**Supplemental At Customer Meter**													
140	Capacity - kW	307	434	318	111	65	0	0	0	0	0	0	64	
141	Energy - kWh	0	9,461	0	0	0	0	0	0	0	0	0	0	9,461
142	Loss Factor - %	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	
143	Average Cost $/MWH	-	$ 176.70	-	-	-	-	-	-	-	-	-	-	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						Renewable RESOURCES								
3														
4		January	February	March	April	May	June	July	August	September	October	November	December	Total
5		<<------ WINTER SEASON ------>>				<<------ SUMMER SEASON ------>>						<<---- WINTER SEASON ---->>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
7	**1.5 MW GE-1.5sle @ Peach Springs**													
8	Rated Capacity - kW	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
9	Monthly Energy - kWh	201,500	207,700	282,100	316,200	337,900	350,300	313,100	272,800	229,400	207,700	186,000	195,300	3,100,000
10	Percent of Annual Energy - %	6.5%	6.7%	9.1%	10.2%	10.9%	11.3%	10.1%	8.8%	7.4%	6.7%	6.0%	6.3%	100.0%
11	Monthly Capacity Factor - %	18.1%	20.6%	25.3%	29.3%	30.3%	32.4%	28.1%	24.4%	21.2%	18.6%	17.2%	17.5%	23.6%
12	O&M	0.0650												
13	Escalation Rate	2.0%												
14														
15	**65 kW Vestas V-15 @ Peach Springs**													
16	Rated Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Monthly Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Percent of Annual Energy - %	6.5%	6.7%	9.1%	10.2%	10.9%	11.3%	10.1%	8.8%	7.4%	6.7%	6.0%	6.3%	100.0%
19	Monthly Capacity Factor - %	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
20	O&M	0.0650												
21	Escalation Rate	2.0%												
22														
23														
24	2007													
25	**Renewable At CRSP**													
26	Max Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Max Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Scheduled Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Load Factor - %	-	-	-	-	-	-	-	-	-	-	-	-	-
31														
32	**Renewable At Transmission**													
33	Max Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
34	Max Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
35	Scheduled Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
36	Scheduled Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
37	Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
38														
39	**Renewable At 12 kV**													
40	Max Capacity - kW	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
41	Scheduled Capacity - kW	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
42	Capacity $/kW/Month	0	0	0	0	0	0	0	0	0	0	0	0	
43	Capacity Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Max Energy - kWh	201,500	207,700	282,100	316,200	337,900	350,300	313,100	272,800	229,400	207,700	186,000	195,300	3,100,000
45	Scheduled Energy - kWh	201,500	207,700	282,100	316,200	337,900	350,300	313,100	272,800	229,400	207,700	186,000	195,300	3,100,000
46	Energy $/kWh	0.0650	0.0650	0.0650	0.0650	0.0650	0.0650	0.0650	0.0650	0.0650	0.0650	0.0650	0.0650	
47	Energy Cost	$ 13,097.50	$ 13,500.50	$ 18,336.50	$ 20,553.00	$ 21,963.50	$ 22,769.50	$ 20,351.50	$ 17,732.00	$ 14,911.00	$ 13,500.50	$ 12,090.00	$ 12,694.50	$ 201,500.00
48	Load Factor - %	18.1%	20.6%	25.3%	29.3%	30.3%	32.4%	28.1%	24.4%	21.2%	18.6%	17.2%	17.5%	23.6%
49	Total Cost	$ 13,097.50	$ 13,500.50	$ 18,336.50	$ 20,553.00	$ 21,963.50	$ 22,769.50	$ 20,351.50	$ 17,732.00	$ 14,911.00	$ 13,500.50	$ 12,090.00	$ 12,694.50	$ 201,500.00
50	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
51														
52	**Renewable At Customer Meter**													
53	Max Capacity - kW	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
54	Max Energy - kWh	197,470	203,546	276,458	309,876	331,142	343,294	306,838	267,344	224,812	203,546	182,280	191,394	3,038,000
55	Scheduled Capacity - kW	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
56	Scheduled Energy - kWh	197,470	203,546	276,458	309,876	331,142	343,294	306,838	267,344	224,812	203,546	182,280	191,394	3,038,000
57	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
58	Average Cost $/MWH	$ 66.33	$ 66.33	$ 66.33	$ 66.33	$ 66.33	$ 66.33	$ 66.33	$ 66.33	$ 66.33	$ 66.33	$ 66.33	$ 66.33	
59														
60	2008													
61	**Renewable At CRSP**													
62	Max Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
63	Max Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
64	Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
65	Scheduled Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
66	Load Factor - %	-	-	-	-	-	-	-	-	-	-	-	-	-
67														
68	**Renewable At Transmission**													

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	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						Renewable RESOURCES								
3														
4		January	February	March	April	May	June	July	August	September	October	November	December	Total
5		<<---------- WINTER SEASON ---------->>				<<---------- SUMMER SEASON ---------->>						<<---- WINTER SEASON ---->>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
69	Max Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
70	Max Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
71	Scheduled Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
72	Scheduled Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
73	Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
74														
75	**Renewable At 12 kV**													
76	Max Capacity - kW	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
77	Scheduled Capacity - kW	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
78	Capacity $/kW/Month	0	0	0	0	0	0	0	0	0	0	0	0	
79	Capacity Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80	Max Energy - kWh	201,500	207,700	282,100	316,200	337,900	350,300	313,100	272,800	229,400	207,700	186,000	195,300	3,100,000
81	Scheduled Energy - kWh	201,500	207,700	282,100	316,200	337,900	350,300	313,100	272,800	229,400	207,700	186,000	195,300	3,100,000
82	Energy $/kWh	0.0663	0.0663	0.0663	0.0663	0.0663	0.0663	0.0663	0.0663	0.0663	0.0663	0.0663	0.0663	
83	Energy Cost	$ 13,359.45	$ 13,770.51	$ 18,703.23	$ 20,964.06	$ 22,402.77	$ 23,224.89	$ 20,758.53	$ 18,086.64	$ 15,209.22	$ 13,770.51	$ 12,331.80	$ 12,948.39	$ 205,530.00
84	Load Factor - %	18.1%	20.6%	25.3%	29.3%	30.3%	32.4%	28.1%	24.4%	21.2%	18.6%	17.2%	17.5%	23.6%
85	Total Cost	$ 13,359.45	$ 13,770.51	$ 18,703.23	$ 20,964.06	$ 22,402.77	$ 23,224.89	$ 20,758.53	$ 18,086.64	$ 15,209.22	$ 13,770.51	$ 12,331.80	$ 12,948.39	
86	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
87														
88	**Renewable At Customer Meter**													
89	Max Capacity - kW	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
90	Max Energy - kWh	197,470	203,546	276,458	309,876	331,142	343,294	306,838	267,344	224,812	203,546	182,280	191,394	3,038,000
91	Scheduled Capacity - kW	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
92	Scheduled Energy - kWh	197,470	203,546	276,458	309,876	331,142	343,294	306,838	267,344	224,812	203,546	182,280	191,394	3,038,000
93	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
94	Average Cost $/MWH	$ 67.65	$ 67.65	$ 67.65	$ 67.65	$ 67.65	$ 67.65	$ 67.65	$ 67.65	$ 67.65	$ 67.65	$ 67.65	$ 67.65	
95														
96	**2009**													
97	**Renewable At CRSP**													
98	Max Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
99	Max Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
100	Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
101	Scheduled Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
102	Load Factor - %	-	-	-	-	-	-	-	-	-	-	-	-	-
103														
104	**Renewable At Transmission**													
105	Max Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
106	Max Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
107	Scheduled Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
108	Scheduled Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
109	Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
110														
111	**Renewable At 12 kV**													
112	Max Capacity - kW	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
113	Scheduled Capacity - kW	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
114	Capacity $/kW/Month	0	0	0	0	0	0	0	0	0	0	0	0	
115	Capacity Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
116	Max Energy - kWh	201,500	207,700	282,100	316,200	337,900	350,300	313,100	272,800	229,400	207,700	186,000	195,300	3,100,000
117	Scheduled Energy - kWh	201,500	207,700	282,100	316,200	337,900	350,300	313,100	272,800	229,400	207,700	186,000	195,300	3,100,000
118	Energy $/kWh	0.0676	0.0676	0.0676	0.0676	0.0676	0.0676	0.0676	0.0676	0.0676	0.0676	0.0676	0.0676	
119	Energy Cost	$ 13,626.64	$ 14,045.92	$ 19,077.29	$ 21,383.34	$ 22,850.83	$ 23,689.39	$ 21,173.70	$ 18,448.37	$ 15,513.40	$ 14,045.92	$ 12,578.44	$ 13,207.36	$ 209,640.60
120	Load Factor - %	18.1%	20.6%	25.3%	29.3%	30.3%	32.4%	28.1%	24.4%	21.2%	18.6%	17.2%	17.5%	23.6%
121	Total Cost	$ 13,626.64	$ 14,045.92	$ 19,077.29	$ 21,383.34	$ 22,850.83	$ 23,689.39	$ 21,173.70	$ 18,448.37	$ 15,513.40	$ 14,045.92	$ 12,578.44	$ 13,207.36	$ 209,640.60
122	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
123														
124	**Renewable At Customer Meter**													
125	Max Capacity - kW	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
126	Max Energy - kWh	197,470	203,546	276,458	309,876	331,142	343,294	306,838	267,344	224,812	203,546	182,280	191,394	3,038,000
127	Scheduled Capacity - kW	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
128	Scheduled Energy - kWh	197,470	203,546	276,458	309,876	331,142	343,294	306,838	267,344	224,812	203,546	182,280	191,394	3,038,000
129	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
130	Average Cost $/MWH	$ 69.01	$ 69.01	$ 69.01	$ 69.01	$ 69.01	$ 69.01	$ 69.01	$ 69.01	$ 69.01	$ 69.01	$ 69.01	$ 69.01	
131														
132	**2010**													

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	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						Renewable RESOURCES								
3														
4		January	February	March	April	May	June	July	August	September	October	November	December	Total
5		<<——— WINTER SEASON ———>>				<<——— SUMMER SEASON ———>>						<<—— WINTER SEASON ——>>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
133	Renewable At CRSP													
134	Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
135	Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
136	Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
137	Scheduled Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
138	Load Factor - %	-	-	-	-	-	-	-	-	-	-	-	-	-
139														
140	Renewable At Transmission													
141	Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
142	Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
143	Scheduled Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
144	Scheduled Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
145	Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
146														
147	Renewable At 12 kV													
148	Max Capacity - kW	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
149	Scheduled Capacity - kW	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
150	Capacity $/kW/Month	0	0	0	0	0	0	0	0	0	0	0	0	
151	Capacity Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
152	Max Energy - kWh	201,500	207,700	282,100	316,200	337,900	350,300	313,100	272,800	229,400	207,700	186,000	195,300	3,100,000
153	Scheduled Energy - kWh	201,500	207,700	282,100	316,200	337,900	350,300	313,100	272,800	229,400	207,700	186,000	195,300	3,100,000
154	Energy $/kWh	0.0690	0.0690	0.0690	0.0690	0.0690	0.0690	0.0690	0.0690	0.0690	0.0690	0.0690	0.0690	
155	Energy Cost	$ 13,899.17	$ 14,326.84	$ 19,458.84	$ 21,811.01	$ 23,307.84	$ 24,163.18	$ 21,597.17	$ 18,817.34	$ 15,823.67	$ 14,326.84	$ 12,830.00	$ 13,471.50	$ 213,833.41
156	Load Factor - %	18.1%	20.6%	25.3%	29.3%	30.3%	32.4%	28.1%	24.4%	21.2%	18.6%	17.2%	17.5%	23.6%
157	Total Cost	$ 13,899.17	$ 14,326.84	$ 19,458.84	$ 21,811.01	$ 23,307.84	$ 24,163.18	$ 21,597.17	$ 18,817.34	$ 15,823.67	$ 14,326.84	$ 12,830.00	$ 13,471.50	$ 213,833.41
158	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
159														
160	Renewable At Customer Meter													
161	Max Capacity - kW	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
162	Max Energy - kWh	197,470	203,546	276,458	309,876	331,142	343,294	306,838	267,344	224,812	203,546	182,280	191,394	3,038,000
163	Scheduled Capacity - kW	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	17,640
164	Scheduled Energy - kWh	197,470	203,546	276,458	309,876	331,142	343,294	306,838	267,344	224,812	203,546	182,280	191,394	3,038,000
165	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
166	Average Cost $/MWH	$ 70.39	$ 70.39	$ 70.39	$ 70.39	$ 70.39	$ 70.39	$ 70.39	$ 70.39	$ 70.39	$ 70.39	$ 70.39	$ 70.39	
167														
168	2011													
169	Renewable At CRSP													
170	Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
171	Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
172	Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
173	Scheduled Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
174	Load Factor - %	-	-	-	-	-	-	-	-	-	-	-	-	-
175														
176	Renewable At Transmission													
177	Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
178	Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
179	Scheduled Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
180	Scheduled Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
181	Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
182														
183	Renewable At 12 kV													
184	Max Capacity - kW	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
185	Scheduled Capacity - kW	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
186	Capacity $/kW/Month	0	0	0	0	0	0	0	0	0	0	0	0	
187	Capacity Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
188	Max Energy - kWh	201,500	207,700	282,100	316,200	337,900	350,300	313,100	272,800	229,400	207,700	186,000	195,300	3,100,000
189	Scheduled Energy - kWh	201,500	207,700	282,100	316,200	337,900	350,300	313,100	272,800	229,400	207,700	186,000	195,300	3,100,000
190	Energy $/kWh	0.0704	0.0704	0.0704	0.0704	0.0704	0.0704	0.0704	0.0704	0.0704	0.0704	0.0704	0.0704	
191	Energy Cost	$ 14,177.16	$ 14,613.38	$ 19,848.02	$ 22,247.23	$ 23,774.00	$ 24,646.44	$ 22,029.12	$ 19,193.69	$ 16,140.15	$ 14,613.38	$ 13,086.60	$ 13,740.94	$ 218,110.08
192	Load Factor - %	18.1%	20.6%	25.3%	29.3%	30.3%	32.4%	28.1%	24.4%	21.2%	18.6%	17.2%	17.5%	23.6%
193	Total Cost	$ 14,177.16	$ 14,613.38	$ 19,848.02	$ 22,247.23	$ 23,774.00	$ 24,646.44	$ 22,029.12	$ 19,193.69	$ 16,140.15	$ 14,613.38	$ 13,086.60	$ 13,740.94	$ 218,110.08
194	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
195														
196	Renewable At Customer Meter													

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	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						Renewable RESOURCES								
3														
4		January	February	March	April	May	June	July	August	September	October	November	December	Total
5		<<———— WINTER SEASON ————>>				<<———— SUMMER SEASON ————>>						<<=== WINTER SEASON ——>>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
197	Max Capacity - kW	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
198	Max Energy - kWh	197,470	203,546	276,458	309,876	331,142	343,294	306,838	267,344	224,812	203,546	182,280	191,394	3,038,000
199	Scheduled Capacity - kW	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
200	Scheduled Energy - kWh	197,470	203,546	276,458	309,876	331,142	343,294	306,838	267,344	224,812	203,546	182,280	191,394	3,038,000
201	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
202	Average Cost $/MWH	$ 71.79	$ 71.79	$ 71.79	$ 71.79	$ 71.79	$ 71.79	$ 71.79	$ 71.79	$ 71.79	$ 71.79	$ 71.79	$ 71.79	

CASE A - Debtservice

	A	B	C	D	E	F	G	H
1		Pre FY2007 Loan 1	Wind Turbines	FY2007	FY2008	FY2009	FY2010	FY2011
2								
3	Adjustment Percent			0.0%	0.0%	0.0%	0.0%	0.0%
4	Facilities			$ 210,000	$ -	$ -	$ -	$ -
5	Equipment			$ -	$ 200,000	$ 200,000	$ 200,000	$ 200,000
6	Total	0	$ 2,347,500	$ 210,000	$ 200,000	$ 200,000	$ 200,000	$ 200,000
7								
8	Principal amount	$ -	$ (2,347,500)	$ (210,000)	$ (200,000)	$ (200,000)	$ (200,000)	$ (200,000)
9	Annual Interest Rate	8.00%	5.50%	8.00%	8.0%	8.0%	8.0%	8.0%
10	Interest Rate	0.6667%	0.4583%	0.6667%	0.6667%	0.6667%	0.6667%	0.6667%
11	Number of Years	30	20	30	30	30	30	30
12	Number of Payments	360	240	360	360	360	360	360
13	Payment Due	1	1	1	1	1	1	1
14	Levelized Pymt Amt	$0.00	$16,074.48	$1,530.70	$1,457.81	$1,457.81	$1,457.81	$1,457.81
15	Annual Payment	$0.00	$192,893.76	$18,368.41				
16								
17								
18		Wind Generators						
19	Capacity	1,500	65	1,565				
20	Cost $/kW	1,500	1,500					
21	Cost $	$ 2,250,000	$ 97,500	$ 2,347,500				
22								
23								
24				Annual Summary				
25		**FY2007**	**FY2008**	**FY2009**	**FY2010**	**FY2011**		
26	Wind Turbines	$ 192,894	$ 192,894	$ 192,894	$ 192,894	$ 192,894		
27	FY2007	$ 18,368	$ 18,368	$ 18,368	$ 18,368	$ 18,368		
28	FY2008	$ -	$ 17,494	$ 17,494	$ 17,494	$ 17,494		
29	FY2009	$ -	$ -	$ 17,494	$ 17,494	$ 17,494		
30	FY2010	$ -	$ -	$ -	$ 17,494	$ 17,494		
31	FY2011	$ -	$ -	$ -	$ -	$ 17,494		
32	Total Debt Service	$ 211,262	$ 228,756	$ 246,250	$ 263,743	$ 281,237		

See Assumptions worksheet. Based upon 1/2 (RCNLD + OCLD)

Estimate for Capital Cost For Wind Generators @ $1,500 per kW

BASE CASE GRAND CANYON WEST

GWC Base Load Forecast

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	Customer		January	February	March	April	May	June	July	August	September	October	November	December	Total	
2			<<———— WINTER SEASON ————>>			<<———— SUMMER SEASON ————>>						<<———— WINTER SEASON ————>>				
3			744	672	744	720	744	720	744	744	720	744	720	744	8760	Check Column
4	Grand Canyon West															
5		Annual Energy or Load Factor														
6	Air terminal	225,000	16,894	16,555	16,953	15,711	16,074	19,017	18,126	21,255	22,740	21,084	21,151	19,440	225,000	
7	Air Operations Buildings	0.00%	0	0	0	0	0	0	0	0	0	0	0	0	-	
8	Air Field Lighting	0.00%	0	0	0	0	0	0	0	0	0	0	0	0	-	
9	Parking & Exterior	0.00%	0	0	0	0	0	0	0	0	0	0	0	0	-	
10	Rim Venues	40.00%	0	0	0	0	0	0	0	0	0	0	0	0	-	
11	Wastewater Plant	100.00%	0	0	0	0	0	0	0	0	0	0	0	0	-	
12	RV Park	30.00%	0	0	0	0	0	0	0	0	0	0	0	0	-	
13	Commercial area	50.00%	0	0	0	0	0	0	0	0	0	0	0	0	-	
14	Residential	388,800	29,193	28,606	29,294	27,148	27,777	32,862	31,321	36,729	39,295	36,433	36,549	33,591	388,800	
15	GCW Monthly Energy		46,088	45,161	46,247	42,859	43,851	51,879	49,447	57,984	62,035	57,517	57,700	53,031	613,800	
16	Percent of Annual - %		7.51%	7.36%	7.53%	6.98%	7.14%	8.45%	8.06%	9.45%	10.11%	9.37%	9.40%	8.64%	100.00%	
17		Estimated Input														
18	Air terminal	50	38	37	37	37	38	40	39	42	50	46	47	45	50	
19	Air Operations Buildings	Part of Air Terminal	0	0	0	0	0	0	0	0	0	0	0	0	-	
20	Air Field Lighting	Part of Air Terminal	0	0	0	0	0	0	0	0	0	0	0	0	-	
21	Parking & Exterior	Part of Air Terminal	0	0	0	0	0	0	0	0	0	0	0	0	-	
22	Rim Venues	0	0	-	-	-	-	-	-	-	-	-	-	-	-	
23	Wastewater Plant	0	0	-	-	-	-	-	-	-	-	-	-	-	-	
24	RV Park	0	0	-	-	-	-	-	-	-	-	-	-	-	-	
25	Commercial area	0	0	-	-	-	-	-	-	-	-	-	-	-	-	
26	Residential	100	76	74	75	73	76	80	79	84	100	93	93	90	100	
27	GCW Monthly Peak	kW	115	111	112	110	115	120	118	126	150	139	140	136	150	
28	Percent of Peak - %		76.3%	74.0%	74.9%	73.2%	76.3%	79.9%	78.7%	84.1%	100.0%	92.8%	93.2%	90.4%	100.0%	
29																
30	Base Year Energy Cost - $kWh		0.5080	0.5080	0.5080	0.5080	0.5080	0.5080	0.5080	0.5080	0.5080	0.5080	0.5080	0.5080		
31		Year	2,007	2,008	2,009	2,010	2,011									
32	Average Energy Cost - $/kWh		0.5060	0.5210	0.5360	0.5510	0.5670									
33	Net Profit / (Loss)		$ 84	$ 483	$ 585	$ 361	$ 461									
34	Base Estimates															
35		Total kW h	46,088	45,161	46,247	42,859	43,851	51,879	49,447	57,984	62,035	57,517	57,700	53,031	613,800	
36		kW	115	111	112	110	115	120	118	126	150	139	140	136	150	
37		Total Due	$ 23,412	$ 22,942	$ 23,493	$ 21,772	$ 22,276	$ 26,355	$ 25,119	$ 29,456	$ 31,514	$ 29,219	$ 29,312	$ 26,940	$ 311,810	
38	Forecasted Load															
39	2007	Growth Rate	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%		
40		# of Customers	30	30	30	30	30	30	30	30	30	30	30	30		
41		Total kWh	47,009	46,064	47,172	43,716	44,728	52,917	50,436	59,144	63,276	58,668	58,854	54,092	626,076	
42		kW	117	113	115	112	117	122	120	129	153	142	143	138	153	Total Max
43		Total Due	$ 23,787	$ 23,309	$ 23,869	$ 22,121	$ 22,632	$ 26,776	$ 25,521	$ 29,927	$ 32,017	$ 29,686	$ 29,780	$ 27,370	$ 316,794	
44	2008		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%		
45		# of Customers	30	30	30	30	30	30	30	30	30	30	30	30		
46		Total kWh	47,950	46,986	48,115	44,591	45,623	53,975	51,445	60,327	64,541	59,841	60,031	55,173	638,598	
47		kW	119	115	117	114	119	125	123	131	156	145	145	141	156	Total Max
48		Total Due	$ 24,982	$ 24,480	$ 25,068	$ 23,232	$ 23,769	$ 28,121	$ 26,803	$ 31,430	$ 33,626	$ 31,177	$ 31,276	$ 28,745	$ 332,709	
49	2009		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%		
50		# of Customers	30	30	30	30	30	30	30	30	30	30	30	30		
51		Total kWh	48,909	47,925	49,077	45,483	46,535	55,055	52,474	61,533	65,832	61,038	61,232	56,277	651,369	
52		kW	122	118	119	116	122	127	125	134	159	148	148	144	159	Total Max
53		Total Due	$ 26,215	$ 25,688	$ 26,306	$ 24,379	$ 24,943	$ 29,509	$ 28,126	$ 32,982	$ 35,286	$ 32,716	$ 32,820	$ 30,164	$ 349,134	
54	2010		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%		
55		# of Customers	30	30	30	30	30	30	30	30	30	30	30	30		
56		Total kWh	49,887	48,884	50,059	46,392	47,466	56,156	53,523	62,764	67,148	62,259	62,456	57,402	664,397	
57		kW	124	120	122	119	124	130	128	136	162	151	151	147	162	Total Max
58		Total Due	$ 27,488	$ 26,935	$ 27,583	$ 25,562	$ 26,154	$ 30,942	$ 29,491	$ 34,583	$ 36,999	$ 34,304	$ 34,413	$ 31,629	$ 366,083	
59	2011		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%		
60		# of Customers	30	30	30	30	30	30	30	30	30	30	30	30		
61		Total kWh	50,884	49,862	51,060	47,320	48,415	57,279	54,594	64,019	68,491	63,504	63,706	58,550	677,685	
62		kW	126	123	124	121	126	132	130	139	166	154	154	150	166	Total Max
63		Total Due	$ 28,851	$ 28,272	$ 28,951	$ 26,830	$ 27,451	$ 32,477	$ 30,955	$ 36,299	$ 38,835	$ 36,007	$ 36,121	$ 33,198	$ 384,247	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						RESOURCES VERSUS LOADS								
3		January	February	March	April	May	June	July	August	September	October	November	December	Total
4	CRSP Season	<<———— WINTER SEASON ————>>			<<———— SUMMER SEASON ————>>						<<———— WINTER SEASON ————>>			
5	Supplemental Season	<<———— WINTER SEASON ————>>				<<———— SUMMER SEASON ————>>						<<—— WINTER SEASON ——>>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
7	2007													
8	RESOURCES													
9	At CRSP Delivery													
10	Max CRSP Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Max CRSP Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Max WRP kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Max CRSP Aggregate kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Solar Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Solar Scheduled Capacity - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Supplemental Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Supplemental Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Total Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Total Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
20	At Meter													
21	CRSP Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
22	CRSP & WRP Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Solar Scheduled Capacity - kW	32	32	32	32	32	32	32	32	32	32	32	32	32
24	Solar Scheduled Capacity - kWh	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	69,854
25	Supplemental Capacity - kW	84	81	82	80	84	90	88	96	121	110	110	106	121
26	Supplemental Energy - kWh	41,188	40,243	41,351	37,895	38,907	47,096	44,615	53,323	57,454	52,846	53,033	48,270	556,222
27	Total Capacity - kW	117	113	115	112	117	122	120	129	153	142	143	138	153
28	Total Energy -kWh	47,009	46,064	47,172	43,716	44,728	52,917	50,436	59,144	63,276	58,668	58,854	54,092	626,076
29														
30	Load At Meter													
31	Demand													
32	Grand Canyon West	117	113	115	112	117	122	120	129	153	142	143	138	
33	TBD - GWC-2	-	-	-	-	-	-	-	-	-	-	-	-	
34	Hualapai Other	-	-	-	-	-	-	-	-	-	-	-	-	
35	TBD - GWC-3	-	-	-	-	-	-	-	-	-	-	-	-	
36	Demand Subtotal	117	113	115	112	117	122	120	129	153	142	143	138	153
37	Energy													
38	Grand Canyon West	47,009	46,064	47,172	43,716	44,728	52,917	50,436	59,144	63,276	58,668	58,854	54,092	
39	TBD - GWC-2	-	-	-	-	-	-	-	-	-	-	-	-	
40	Hualapai Other	-	-	-	-	-	-	-	-	-	-	-	-	
41	TBD - GWC-3	-	-	-	-	-	-	-	-	-	-	-	-	
42	Energy Subtotal	47,009	46,064	47,172	43,716	44,728	52,917	50,436	59,144	63,276	58,668	58,854	54,092	626,076
43														
44	Resource Vs. Load At Meter													
45	Capacity Excess/(Deficiency) {1}	-	-	-	-	-	-	-	-	-	-	-	-	-
46	Energy Excess/(Deficiency) {2}	-	-	-	-	-	-	-	-	-	-	-	-	-
47														
48	2008													
49	RESOURCES													
50	At CRSP Delivery													
51	CRSP Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
52	CRSP Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
53	WRP kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
54	Aggregate kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
55	Solar Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
56	Solar Scheduled Capacity - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
57	Supplemental Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
58	Supplemental Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
59	Total Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
60	Total Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
61	At Meter													
62	CRSP Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
63	CRSP & WRP Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
64	Solar Scheduled Capacity - kW	32	32	32	32	32	32	32	32	32	32	32	32	32
65	Solar Scheduled Capacity - kWh	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	69,854
66	Supplemental Capacity - kW	87	83	84	82	87	92	90	99	124	112	113	109	124

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	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						RESOURCES VERSUS LOADS								
3		January	February	March	April	May	June	July	August	September	October	November	December	Total
4	CRSP Season	<<———— WINTER SEASON ————>>			<<———— SUMMER SEASON ————>>						<<———— WINTER SEASON ————>>			
5	Supplemental Season	<<———— WINTER SEASON ————>>				<<———— SUMMER SEASON ————>>						<<—— WINTER SEASON ——>>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
67	Supplemental Energy - kWh	42,128	41,164	42,294	38,770	39,802	48,154	45,624	54,505	58,720	54,020	54,210	49,352	568,743
68	Total Capacity - kW	119	115	117	114	119	125	123	131	156	145	145	141	156
69	Total Energy -kWh	47,950	46,986	48,115	44,591	45,623	53,975	51,445	60,327	64,541	59,841	60,031	55,173	638,598
70														
71	Load At Meter													
72	**Demand**													
73	Grand Canyon West	119	115	117	114	119	125	123	131	156	145	145	141	
74	TBD - GWC-2	-	-	-	-	-	-	-	-	-	-	-	-	
75	Hualapai Other	-	-	-	-	-	-	-	-	-	-	-	-	
76	TBD - GWC-3	-	-	-	-	-	-	-	-	-	-	-	-	
77	**Demand Subtotal**	**119**	**115**	**117**	**114**	**119**	**125**	**123**	**131**	**156**	**145**	**145**	**141**	156
78	**Energy**													
79	Grand Canyon West	47,950	46,986	48,115	44,591	45,623	53,975	51,445	60,327	64,541	59,841	60,031	55,173	
80	TBD - GWC-2	-	-	-	-	-	-	-	-	-	-	-	-	
81	Hualapai Other	-	-	-	-	-	-	-	-	-	-	-	-	
82	TBD - GWC-3	-	-	-	-	-	-	-	-	-	-	-	-	
83	**Energy Subtotal**	**47,950**	**46,986**	**48,115**	**44,591**	**45,623**	**53,975**	**51,445**	**60,327**	**64,541**	**59,841**	**60,031**	**55,173**	638,598
84														
85	Resource Vs. Load At Meter													
86	Capacity Excess/(Deficiency) {1}	-	-	-	-	-	-	-	-	-	-	-	-	-
87	Energy Excess/(Deficiency) {2}	-	-	-	-	-	-	-	-	-	-	-	-	-
88														
89	2009													
90	**RESOURCES**													
91	At CRSP Delivery													
92	CRSP Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
93	CRSP Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
94	WRP kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
95	Aggregate kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
96	Solar Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
97	Solar Scheduled Capacity - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
98	Supplemental Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
99	Supplemental Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
100	Total Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
101	Total Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
102	At Meter													
103	CRSP Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
104	CRSP & WRP Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
105	Solar Scheduled Capacity - kW	32	32	32	32	32	32	32	32	32	32	32	32	32
106	Solar Scheduled Capacity - kWh	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	69,854
107	Supplemental Capacity - kW	89	85	87	84	89	95	93	101	127	115	116	112	0
108	Supplemental Energy - kWh	43,087	42,104	43,256	39,661	40,714	49,234	46,653	55,712	60,011	55,217	55,411	50,456	0
109	Total Capacity - kW	122	118	119	116	122	127	125	134	159	148	148	144	159
110	Total Energy -kWh	48,909	47,925	49,077	45,483	46,535	55,055	52,474	61,533	65,832	61,038	61,232	56,277	651,369
111														
112	Load At Meter													
113	**Demand**													
114	Grand Canyon West	122	118	119	116	122	127	125	134	159	148	148	144	
115	TBD - GWC-2	-	-	-	-	-	-	-	-	-	-	-	-	
116	Hualapai Other	-	-	-	-	-	-	-	-	-	-	-	-	
117	TBD - GWC-3	-	-	-	-	-	-	-	-	-	-	-	-	
118	**Demand Subtotal**	**122**	**118**	**119**	**116**	**122**	**127**	**125**	**134**	**159**	**148**	**148**	**144**	159
119	**Energy**													
120	Grand Canyon West	48,909	47,925	49,077	45,483	46,535	55,055	52,474	61,533	65,832	61,038	61,232	56,277	
121	TBD - GWC-2	-	-	-	-	-	-	-	-	-	-	-	-	
122	Hualapai Other	-	-	-	-	-	-	-	-	-	-	-	-	
123	TBD - GWC-3	-	-	-	-	-	-	-	-	-	-	-	-	
124	**Energy Subtotal**	**48,909**	**47,925**	**49,077**	**45,483**	**46,535**	**55,055**	**52,474**	**61,533**	**65,832**	**61,038**	**61,232**	**56,277**	651,369
125														
126	Resource Vs. Load At Meter													

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	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1					Hualapai									
2					RESOURCES VERSUS LOADS									
3		January	February	March	April	May	June	July	August	September	October	November	December	Total
4	CRSP Season	<<—— WINTER SEASON ——>>			<<—— SUMMER SEASON ——>>						<<—— WINTER SEASON ——>>			
5	Supplemental Season	<<—— WINTER SEASON ——>>				<<—— SUMMER SEASON ——>>						<<—— WINTER SEASON ——>>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
127	Capacity Excess/(Deficiency) {1}	-	-	-	-	-	-	-	-	-	-	-	-	-
128	Energy Excess/(Deficiency) {2}	-	-	-	-	-	-	-	-	-	-	-	-	-
129														
130	2010													
131	RESOURCES													
132	At CRSP Delivery													
133	CRSP Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
134	CRSP Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
135	WRP kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
136	Aggregate kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
137	Solar Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
138	Solar Scheduled Capacity - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
139	Supplemental Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
140	Supplemental Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
141	Total Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
142	Total Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
143	At Meter													
144	CRSP Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
145	CRSP & WRP Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
146	Solar Scheduled Capacity - kW	32	32	32	32	32	32	32	32	32	32	32	32	32
147	Solar Scheduled Capacity - kWh	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	69,854
148	Supplemental Capacity - kW	92	88	89	86	92	97	95	104	130	118	119	114	0
149	Supplemental Energy - kWh	44,065	43,063	44,238	40,571	41,645	50,335	47,702	56,943	61,327	56,437	56,635	51,581	0
150	Total Capacity - kW	124	120	122	119	124	130	128	136	162	151	151	147	162
151	Total Energy -kWh	49,887	48,884	50,059	46,392	47,466	56,156	53,523	62,764	67,148	62,259	62,456	57,402	664,397
152														
153	Load At Meter													
154	Demand													
155	Grand Canyon West	124	120	122	119	124	130	128	136	162	151	151	147	
156	TBD - GWC-2	-	-	-	-	-	-	-	-	-	-	-	-	
157	Hualapai Other	-	-	-	-	-	-	-	-	-	-	-	-	
158	TBD - GWC-3	-	-	-	-	-	-	-	-	-	-	-	-	
159	**Demand Subtotal**	**124**	**120**	**122**	**119**	**124**	**130**	**128**	**136**	**162**	**151**	**151**	**147**	162
160	Energy													
161	Grand Canyon West	49,887	48,884	50,059	46,392	47,466	56,156	53,523	62,764	67,148	62,259	62,456	57,402	
162	TBD - GWC-2	-	-	-	-	-	-	-	-	-	-	-	-	
163	Hualapai Other	-	-	-	-	-	-	-	-	-	-	-	-	
164	TBD - GWC-3	-	-	-	-	-	-	-	-	-	-	-	-	
165	**Energy Subtotal**	**49,887**	**48,884**	**50,059**	**46,392**	**47,466**	**56,156**	**53,523**	**62,764**	**67,148**	**62,259**	**62,456**	**57,402**	664,397
166														
167	Resource Vs. Load At Meter													
168	Capacity Excess/(Deficiency) {1}	-	-	-	-	-	-	-	-	-	-	-	-	-
169	Energy Excess/(Deficiency) {2}	-	-	-	-	-	-	-	-	-	-	-	-	-
170														
171	2011													
172	RESOURCES													
173	At CRSP Delivery													
174	CRSP Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
175	CRSP Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
176	WRP kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
177	Aggregate kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
178	Solar Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
179	Solar Scheduled Capacity - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
180	Supplemental Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
181	Supplemental Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
182	Total Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
183	Total Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
184	At Meter													
185	CRSP Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
186	CRSP & WRP Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						RESOURCES VERSUS LOADS								
3		January	February	March	April	May	June	July	August	September	October	November	December	Total
4	CRSP Season	<<——— WINTER SEASON ———>>			<<——— SUMMER SEASON ———>>						<<——— WINTER SEASON ———>>			
5	Supplemental Season	<<——— WINTER SEASON ———>>				<<——— SUMMER SEASON ———>>						<<—— WINTER SEASON ——>>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
187	Solar Scheduled Capacity - kW	32	32	32	32	32	32	32	32	32	32	32	32	32
188	Solar Scheduled Capacity - kWh	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	69,854
189	Supplemental Capacity - kW	94	90	92	89	94	100	98	107	133	121	122	117	0
190	Supplemental Energy - kWh	45,063	44,040	45,239	41,499	42,594	51,458	48,773	58,198	62,670	57,683	57,884	52,729	0
191	Total Capacity - kW	126	123	124	121	126	132	130	139	166	154	154	150	166
192	Total Energy -kWh	50,884	49,862	51,060	47,320	48,415	57,279	54,594	64,019	68,491	63,504	63,706	58,550	677,685
193														
194	Load At Meter													
195	**Demand**													
196	Grand Canyon West	126	123	124	121	126	132	130	139	166	154	154	150	
197	TBD - GWC-2	-	-	-	-	-	-	-	-	-	-	-	-	
198	Hualapai Other	-	-	-	-	-	-	-	-	-	-	-	-	
199	TBD - GWC-3	-	-	-	-	-	-	-	-	-	-	-	-	
200	**Demand Subtotal**	**126**	**123**	**124**	**121**	**126**	**132**	**130**	**139**	**166**	**154**	**154**	**150**	166
201	**Energy**													
202	Grand Canyon West	50,884	49,862	51,060	47,320	48,415	57,279	54,594	64,019	68,491	63,504	63,706	58,550	
203	TBD - GWC-2	-	-	-	-	-	-	-	-	-	-	-	-	
204	Hualapai Other	-	-	-	-	-	-	-	-	-	-	-	-	
205	TBD - GWC-3	-	-	-	-	-	-	-	-	-	-	-	-	
206	**Energy Subtotal**	**50,884**	**49,862**	**51,060**	**47,320**	**48,415**	**57,279**	**54,594**	**64,019**	**68,491**	**63,504**	**63,706**	**58,550**	677,685
207														
208	Resource Vs. Load At Meter													
209	Capacity Excess/(Deficiency) {1}	-	-	-	-	-	-	-	-	-	-	-	-	-
210	Energy Excess/(Deficiency) {2}	-	-	-	-	-	-	-	-	-	-	-	-	-
211														
212	{1} Resource Minus Load (i.e., if Resources greater than Loads there is excess;													
213	if Resources less than Loads there is a deficiency)													
214														
215	{2} Resource Minus Load (i.e., if Resources greater than Loads there is excess;													
216	if Resources less than Loads there is a deficiency)													

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						SRP RESOURCES								
3														
4		January	February	March	April	May	June	July	August	September	October	November	December	Total
5		<<—— WINTER SEASON ——>>				<<—— SUMMER SEASON ——>>						<<—— WINTER SEASON ——>>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
7	Solar Maximum Capacity - kW	33	33	33	33	33	33	33	33	33	33	33	33	33
8	Solar Energy- kWh	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	71,280
9	Solar Capacity Factor- kW	24.2%	26.8%	24.2%	25.0%	24.2%	25.0%	24.2%	24.2%	25.0%	24.2%	25.0%	24.2%	24.7%
10	**2007**													
11	**Solar At CRSP**													
12	Max Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Max Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Scheduled Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Load Factor - %	-	-	-	-	-	-	-	-	-	-	-	-	-
17														
18	**Solar At Transmission**													
19	Max Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
20	Max Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
21	Scheduled Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
22	Scheduled Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
23	Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
24														
25	**Solar At Generator**													
26	Max Capacity - kW	33	33	33	33	33	33	33	33	33	33	33	33	33
27	Scheduled Capacity - kW	33	33	33	33	33	33	33	33	33	33	33	33	33
28	Capacity $/kW/Month	0	0	0	0	0	0	0	0	0	0	0	0	
29	Capacity Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	Max Energy - kWh	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	71,280
31	Scheduled Energy - kWh	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	71,280
32	Energy $/kWh	-	-	-	-	-	-	-	-	-	-	-	-	
33	Energy Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Load Factor - %	24.2%	26.8%	24.2%	25.0%	24.2%	25.0%	24.2%	24.2%	25.0%	24.2%	25.0%	24.2%	24.7%
35	Total SRP Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
37														
38														
39	**Solar At Customer Meter**													
40	Max Capacity - kW	32	32	32	32	32	32	32	32	32	32	32	32	32
41	Max Energy - kWh	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	69,854
42	Scheduled Capacity - kW	32	32	32	32	32	32	32	32	32	32	32	32	32
43	Scheduled Energy - kWh	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	69,854
44	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
45	Average Cost $/MWH	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
46														
47	**2008**													
48	**Solar At CRSP**													
49	Max Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
50	Max Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
51	Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
52	Scheduled Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
53	Load Factor - %	-	-	-	-	-	-	-	-	-	-	-	-	-
54														
55	**Solar At Transmission**													
56	Max Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
57	Max Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
58	Scheduled Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
59	Scheduled Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
60	Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
61														
62	**Solar At Generator**													
63	Max Capacity - kW	33	33	33	33	33	33	33	33	33	33	33	33	33
64	Scheduled Capacity - kW	33	33	33	33	33	33	33	33	33	33	33	33	33
65	Capacity $/kW/Month	0	0	0	0	0	0	0	0	0	0	0	0	
66	Capacity Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	Max Energy - kWh	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	71,280
68	Scheduled Energy - kWh	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	71,280
69	Energy $/kWh	-	-	-	-	-	-	-	-	-	-	-	-	
70	Energy Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						SRP RESOURCES								
3														
4		January	February	March	April	May	June	July	August	September	October	November	December	Total
5		<<————	WINTER SEASON	————	————>>	<<————	————	————	SUMMER SEASON	————	————>>	<<—— WINTER SEASON	——>>	
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
71	Load Factor - %	24.2%	26.8%	24.2%	25.0%	24.2%	25.0%	24.2%	24.2%	25.0%	24.2%	25.0%	24.2%	24.7%
72	Total SRP Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
73	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
74														
75	Solar At Customer Meter													
76	Max Capacity - kW	32	32	32	32	32	32	32	32	32	32	32	32	32
77	Max Energy - kWh	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	69,854
78	Scheduled Capacity - kW	32	32	32	32	32	32	32	32	32	32	32	32	32
79	Scheduled Energy - kWh	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	69,854
80	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
81	Average Cost $/MWH	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
82														
83	2009													
84	Solar At CRSP													
85	Max Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
86	Max Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
87	Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
88	Scheduled Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
89	Load Factor - %	-	-	-	-	-	-	-	-	-	-	-	-	-
90														
91	Solar At Transmission													
92	Max Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
93	Max Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
94	Scheduled Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
95	Scheduled Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
96	Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
97														
98	Solar At Generator													
99	Max Capacity - kW	33	33	33	33	33	33	33	33	33	33	33	33	33
100	Scheduled Capacity - kW	33	33	33	33	33	33	33	33	33	33	33	33	33
101	Capacity $/kW/Month	0	0	0	0	0	0	0	0	0	0	0	0	
102	Capacity Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
103	Max Energy - kWh	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	71,280
104	Scheduled Energy - kWh	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	71,280
105	Energy $/kWh	-	-	-	-	-	-	-	-	-	-	-	-	
106	Energy Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
107	Load Factor - %	24.2%	26.8%	24.2%	25.0%	24.2%	25.0%	24.2%	24.2%	25.0%	24.2%	25.0%	24.2%	24.7%
108	Total SRP Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
109	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
110														
111	Solar At Customer Meter													
112	Max Capacity - kW	32	32	32	32	32	32	32	32	32	32	32	32	32
113	Max Energy - kWh	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	69,854
114	Scheduled Capacity - kW	32	32	32	32	32	32	32	32	32	32	32	32	32
115	Scheduled Energy - kWh	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	69,854
116	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
117	Average Cost $/MWH	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
118														
119	2010													
120	Solar At CRSP													
121	Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
122	Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
123	Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
124	Scheduled Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
125	Load Factor - %	-	-	-	-	-	-	-	-	-	-	-	-	-
126														
127	Solar At Transmission													
128	Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
129	Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
130	Scheduled Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
131	Scheduled Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
132	Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
133														
134	Solar At Generator													

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						SRP RESOURCES								
3														
4		January	February	March	April	May	June	July	August	September	October	November	December	Total
5		<<—— WINTER SEASON ——>>				<<—— SUMMER SEASON ——>>						<<—— WINTER SEASON ——>>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
135	Max Capacity - kW	33	33	33	33	33	33	33	33	33	33	33	33	33
136	Scheduled Capacity - kW	33	33	33	33	33	33	33	33	33	33	33	33	33
137	Capacity $/kW/Month	0	0	0	0	0	0	0	0	0	0	0	0	
138	Capacity Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
139	Max Energy - kWh	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	71,280
140	Scheduled Energy - kWh	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	71,280
141	Energy $/kWh	-	-	-	-	-	-	-	-	-	-	-	-	
142	Energy Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
143	Load Factor - %	24.2%	26.8%	24.2%	25.0%	24.2%	25.0%	24.2%	24.2%	25.0%	24.2%	25.0%	24.2%	24.7%
144	Total SRP Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
145	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
146														
147	Solar At Customer Meter													
148	Max Capacity - kW	32	32	32	32	32	32	32	32	32	32	32	32	32
149	Max Energy - kWh	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	69,854
150	Scheduled Capacity - kW	32	32	32	32	32	32	32	32	32	32	32	32	388
151	Scheduled Energy - kWh	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	69,854
152	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
153	Average Cost $/MWH	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
154														
155	2011													
156	Solar At CRSP													
157	Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
158	Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
159	Scheduled Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
160	Scheduled Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
161	Load Factor - %	-	-	-	-	-	-	-	-	-	-	-	-	-
162														
163	Solar At Transmission													
164	Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
165	Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
166	Scheduled Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
167	Scheduled Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
168	Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
169														
170	Solar At Generator													
171	Max Capacity - kW	33	33	33	33	33	33	33	33	33	33	33	33	33
172	Scheduled Capacity - kW	33	33	33	33	33	33	33	33	33	33	33	33	33
173	Capacity $/kW/Month	0	0	0	0	0	0	0	0	0	0	0	0	
174	Capacity Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
175	Max Energy - kWh	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	71,280
176	Scheduled Energy - kWh	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	5,940	71,280
177	Energy $/kWh	-	-	-	-	-	-	-	-	-	-	-	-	
178	Energy Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
179	Load Factor - %	24.2%	26.8%	24.2%	25.0%	24.2%	25.0%	24.2%	24.2%	25.0%	24.2%	25.0%	24.2%	24.7%
180	Total SRP Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
181	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
182														
183	Solar At Customer Meter													
184	Max Capacity - kW	32	32	32	32	32	32	32	32	32	32	32	32	32
185	Max Energy - kWh	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	69,854
186	Scheduled Capacity - kW	32	32	32	32	32	32	32	32	32	32	32	32	32
187	Scheduled Energy - kWh	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	5,821	69,854
188	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
189	Average Cost $/MWH	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

A	B	C	D	E	F	G	H	I	J	K	L	M	N
					Hualapai								
					Supplemental RESOURCES								
-													
	January	February	March	April	May	June	July	August	September	October	November	December	Total
	<<———— WINTER SEASON			————>>	<<———— SUMMER SEASON					————>>	<<—— WINTER SEASON	——>>	
Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
2007													
Supplemental At CRSP													
Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
Load Factor - %	-	-	-	-	-	-	-	-	-	-	-	-	-
Supplemental At Transmission													
Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Supplemental At Generator													
Capacity - kW	86	83	84	81	86	92	90	98	123	112	113	108	
Capacity $/kW/Month	-	-	-	-	-	-	-	-	-	-	-	-	
Capacity Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Energy - kWh	42,029	41,064	42,194	38,669	39,701	48,057	45,526	54,411	58,627	53,925	54,115	49,256	
Energy $/kWh	0.5140	0.5140	0.5140	0.5140	0.5140	0.5140	0.5140	0.5140	0.5140	0.5140	0.5140	0.5140	
Energy Cost	$ 21,601	$ 21,106	$ 21,686	$ 19,874	$ 20,405	$ 24,699	$ 23,398	$ 27,965	$ 30,132	$ 27,715	$ 27,813	$ 25,315	
Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
Total Supplemental Cost	$ 21,601	$ 21,106	$ 21,686	$ 19,874	$ 20,405	$ 24,699	$ 23,398	$ 27,965	$ 30,132	$ 27,715	$ 27,813	$ 25,315	$ -
Supplemental At Customer Meter													
Capacity - kW	84	81	82	80	84	90	88	96	121	110	110	106	
Energy - kWh	41,188	40,243	41,351	37,895	38,907	47,096	44,615	53,323	57,454	52,846	53,033	48,270	556,222
Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
Average Cost $/MWH	$ 524.45	$ 524.45	$ 524.45	$ 524.45	$ 524.45	$ 524.45	$ 524.45	$ 524.45	$ 524.45	$ 524.45	$ 524.45	$ 524.45	
2008													
Supplemental At CRSP													
Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
Load Factor - %	-	-	-	-	-	-	-	-	-	-	-	-	-
Supplemental At Transmission													
Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Supplemental At Generator													
Capacity - kW	89	85	86	84	89	94	92	101	126	115	115	111	
Capacity $/kW/Month	-	-	-	-	-	-	-	-	-	-	-	-	
Capacity Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy - kWh	42,988	42,005	43,157	39,561	40,614	49,137	46,555	55,618	59,918	55,122	55,316	50,359	
Energy $/kWh	0.5294	0.5294	0.5294	0.5294	0.5294	0.5294	0.5294	0.5294	0.5294	0.5294	0.5294	0.5294	
Energy Cost	$ 22,757	$ 22,236	$ 22,847	$ 20,943	$ 21,500	$ 26,012	$ 24,645	$ 29,443	$ 31,720	$ 29,181	$ 29,283	$ 26,659	$ 307,226.08
Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
Total Supplemental Cost	$ 22,757	$ 22,236	$ 22,847	$ 20,943	$ 21,500	$ 26,012	$ 24,645	$ 29,443	$ 31,720	$ 29,181	$ 29,283	$ 26,659	$ 307,226.08
Supplemental At Customer Meter													
Capacity - kW	87	83	84	82	87	92	90	99	124	112	113	109	
Energy - kWh	42,128	41,164	42,294	38,770	39,802	48,154	45,624	54,505	58,720	54,020	54,210	49,352	568,743
Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
Average Cost $/MWH	$ 540.18	$ 540.18	$ 540.18	$ 540.18	$ 540.18	$ 540.18	$ 540.18	$ 540.18	$ 540.18	$ 540.18	$ 540.18	$ 540.18	
2009													
Supplemental At CRSP													
Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
Load Factor - %	-	-	-	-	-	-	-	-	-	-	-	-	-
Supplemental At Transmission													
Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	

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	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						Supplemental RESOURCES								
3														
4		January	February	March	April	May	June	July	August	September	October	November	December	Total
5		<<———— WINTER SEASON ————>>				<<———— SUMMER SEASON ————>>						<<—— WINTER SEASON ——>>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
71														
72	**Supplemental At Generator**													
73	Capacity - kW	91	87	89	86	91	97	95	104	129	118	118	114	
74	Capacity $/kW/Month	-	-	-	-	-	-	-	-	-	-	-	-	
75	Capacity Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
76	Energy - kWh	43,967	42,963	44,139	40,471	41,545	50,238	47,605	56,849	61,235	56,343	56,541	51,485	
77	Energy $/kWh	0.5453	0.5453	0.5453	0.5453	0.5453	0.5453	0.5453	0.5453	0.5453	0.5453	0.5453	0.5453	
78	Energy Cost	$ 23,973	$ 23,426	$ 24,067	$ 22,067	$ 22,653	$ 27,393	$ 25,957	$ 30,998	$ 33,389	$ 30,722	$ 30,830	$ 28,073	$ 323,549.05
79	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
80	Total Supplemental Cost	$ 23,973	$ 23,426	$ 24,067	$ 22,067	$ 22,653	$ 27,393	$ 25,957	$ 30,998	$ 33,389	$ 30,722	$ 30,830	$ 28,073	$ 323,549.05
81														
82	**Supplemental At Customer Meter**													
83	Capacity - kW	89	85	87	84	89	95	93	101	127	115	116	112	
84	Energy - kWh	43,087	42,104	43,256	39,661	40,714	49,234	46,653	55,712	60,011	55,217	55,411	50,456	581,515
85	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
86	Average Cost $/MWH	$ 556.39	$ 556.39	$ 556.39	$ 556.39	$ 556.39	$ 556.39	$ 556.39	$ 556.39	$ 556.39	$ 556.39	$ 556.39	$ 556.39	
87														
88	**2010**													
89	**Supplemental At CRSP**													
90	Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
91	Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
92	Energy $/kWh	-	-	-	-	-	-	-	-	-	-	-	-	
93														
94	**Supplemental At Transmission**													
95	Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
96	Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
97	Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
98														
99	**Supplemental At Generator**													
100	Capacity - kW	93	90	91	88	93	99	97	106	133	121	121	117	
101	Capacity $/kW/Month	-	-	-	-	-	-	-	-	-	-	-	-	
102	Capacity Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
103	Energy - kWh	44,965	43,942	45,141	41,399	42,495	51,362	48,676	58,105	62,579	57,589	57,791	52,634	
104	Energy $/kWh	0.5616	0.5616	0.5616	0.5616	0.5616	0.5616	0.5616	0.5616	0.5616	0.5616	0.5616	0.5616	
105	Energy Cost	$ 25,253	$ 24,678	$ 25,352	$ 23,250	$ 23,866	$ 28,846	$ 27,337	$ 32,633	$ 35,146	$ 32,343	$ 32,457	$ 29,560	$ 340,721.27
106	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
107	Total Supplemental Cost	$ 25,253	$ 24,678	$ 25,352	$ 23,250	$ 23,866	$ 28,846	$ 27,337	$ 32,633	$ 35,146	$ 32,343	$ 32,457	$ 29,560	$ 340,721.27
108														
109	**Supplemental At Customer Meter**													
110	Capacity - kW	92	88	89	86	92	97	95	104	130	118	119	114	
111	Energy - kWh	44,065	43,063	44,238	40,571	41,645	50,335	47,702	56,943	61,327	56,437	56,635	51,581	594,542
112	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
113	Average Cost $/MWH	$ 573.08	$ 573.08	$ 573.08	$ 573.08	$ 573.08	$ 573.08	$ 573.08	$ 573.08	$ 573.08	$ 573.08	$ 573.08	$ 573.08	
114														
115	**2011**													
116	**Supplemental At CRSP**													
117	Capacity - kW	0	0	0	0	0	0	0	0	0	0	0	0	0
118	Energy - kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
119	Load Factor - %	-	-	-	-	-	-	-	-	-	-	-	-	-
120														
121	**Supplemental At Transmission**													
122	Capacity - kW	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
123	Energy - kWh	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0
124	Loss Factor - %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
125														
126	**Supplemental At Generator**													
127	Capacity - kW	96	92	94	91	96	102	100	109	136	124	125	120	
128	Capacity $/kW/Month	-	-	-	-	-	-	-	-	-	-	-	-	
129	Capacity Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
130	Energy - kWh	45,983	44,939	46,162	42,346	43,463	52,508	49,768	59,386	63,949	58,860	59,066	53,805	
131	Energy $/kWh	0.5785	0.5785	0.5785	0.5785	0.5785	0.5785	0.5785	0.5785	0.5785	0.5785	0.5785	0.5785	
132	Energy Cost	$ 26,600	$ 25,996	$ 26,703	$ 24,496	$ 25,142	$ 30,374	$ 28,789	$ 34,353	$ 36,993	$ 34,048	$ 34,168	$ 31,125	$ 358,786.43
133	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
134	Total Supplemental Cost	$ 26,600	$ 25,996	$ 26,703	$ 24,496	$ 25,142	$ 30,374	$ 28,789	$ 34,353	$ 36,993	$ 34,048	$ 34,168	$ 31,125	$ 358,786.43

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	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1						Hualapai								
2						Supplemental RESOURCES								
3														
4		January	February	March	April	May	June	July	August	September	October	November	December	Total
5		<<———— WINTER SEASON ————>>				<<———— SUMMER SEASON ————>>						<<—— WINTER SEASON ——>>		
6	Hours	744	672	744	720	744	720	744	744	720	744	720	744	8,760
135														
136	**Supplemental At Customer Meter**													
137	Capacity - kW	94	90	92	89	94	100	98	107	133	121	122	117	
138	Energy - kWh	45,063	44,040	45,239	41,499	42,594	51,458	48,773	58,198	62,670	57,683	57,884	52,729	607,830
139	Loss Factor - %	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
140	Average Cost $/MWH	$ 590.27	$ 590.27	$ 590.27	$ 590.27	$ 590.27	$ 590.27	$ 590.27	$ 590.27	$ 590.27	$ 590.27	$ 590.27	$ 590.27	

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	A	B	C	D	E	F	G	H	I	J	K
1	**GCW Power System Operations and Maintenance Claculations**										
2	**Air Terminal**										
3		Quantity	Units			Avg kW	Estimated Peak Load	Load Factor	Capacity Factor	Annual Energy	
4	Monthly kWh Load	18,750	kWh	625	kWh/day	25.20	50	50.4%		225000	
5	Load Plus Losses	21,563	kWh	719	kWh/day						
6	Monthly kWh Production	25,938	kWh	865	kWh/day	34.86	67		52.0%		
7											
8	System Losses	15%							COST		
9								Annual	Monthly	per kWh @ Load	
10				Cost / unit	Extended Cost						
11											
12	Annual Fuel Consumption	17,762	gallons	$ 2.65	$ 47,070			$ 47,070	3,922.53	$ 0.2092	
13											
14	Annual O&M										
15	Parts										
16	Distilled Water	1200	gallons	$ 1.00	$ 1,200						
17	Genset Engine Oil	45	gallons	$ 10.00	$ 450						
18	Genset Oil Filter	9	each	$ 20.00	$ 180						
19	Genset Fuel Filter	5	each	$ 20.00	$ 100						
20	Genset Air Filter	3	each	$ 20.00	$ 60						
21	Service Calls	4	each	$ 2,500.00	$ 10,000						
22								$ 11,990	$ 999.17	$ 0.0533	
23	Labor										
24	Battery Equalization	96	hour	$ 25.00	$ 2,400						
25	Oil and Filter Change	18	hour	$ 75.00	$ 1,350						
26	Fuel Filter Change	5	hour	$ 75.00	$ 375						
27	Air Filter Change	3	hour	$ 75.00	$ 225						
28								$ 4,350	$ 362.50	$ 0.0193	
29											
30	Replacement Schedule										
31	Batteries	240	each	$ 720	$ 172,800	5.5	years	$ 31,418	2,618.18	$ 0.1396	
32	Inverter	1	each	$ 130,000	$ 130,000	7.5	years	$ 17,333	1,444.44	$ 0.0770	
33	Generator	1	each	$ 35,000	$ 35,000	4.5	years	$ 7,778	648.15	$ 0.0346	
34	Solar Modules	17	kW	$ 4,000	$ 68,000	20	years	$ 3,400	283.33	$ 0.0151	
35											
36	Assumptions			Total O&M Cost / kWh				$ 123,339.65	$ 10,278.30	$ 0.55	
37	Genset kW	50	kW								
38	Average Solar Hours/ day	6	hours/day								
39	Solar Array kW	17	kW				Monthly			Capacity Factor	
40	Daily Solar kWh	102	kWh	Solar kW x Daily Hours			3,060	Solar kWh per month		24.2%	
41	Gen Set kWh/day	617	kWh	Load plus system losses minus Solar kWh			18,503	Gen Set kWh per month		49.7%	
42	Genset Battery Charging hours	12	hours	Genset kWh / genset kW			21,563				
43	Gallons per Hour fuel consumption	4	gal/Hr	From Cat website specs for new 50kW unit + 25%							
44	Daily Fuel Consumption	49	gal/day								
45	Monthly Fuel Consumption	1480	gal/month								
46	Annual Fuel Consumption	17,762	gal/year								

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	A	B	C	D	E	F	G	H	I	J	K
47	**Residential**										
48		Quantity	Units			Avg kW	Estimated Load Factor	kW	# Residents	Avg kW per house	
49	Monthly kWh Load	32,400	kWh	1,080	kWh/day	43.5	40.0%	108.9	25	4.4	388800
50	Load Plus Losses	37,260	kWh	1,242	kWh/day						
51	Monthly kWh Production	40,543	kWh	1,351	kWh/day						
52						May be that energy is to high. Average kW should be more					
53	System Losses	15%						COST			
54								Annual	Monthly	per kWh	
55				Cost / unit	Extended Cost						
56											
57	Annual Fuel Consumption	33,005	gallons	$ 2.65	$ 87,463			$ 87,463	7,288.56	$ 0.2250	
58											
59	Annual O&M										
60	Parts										
61	Distilled Water	1800	gallons	$ 1.00	$ 1,800						
62	Genset Engine Oil	75	gallons	$ 10.00	$ 750						
63	Genset Oil Filter	15	each	$ 20.00	$ 300						
64	Genset Fuel Filter	8	each	$ 20.00	$ 160						
65	Genset Air Filter	5	each	$ 20.00	$ 100						
66	Service Calls	4	each	$ 2,500.00	$ 10,000						
67								$ 13,110	$ 1,092.50	$ 0.0337	
68	Labor										
69	Battery Equalization	144	hour	$ 25.00	$ 3,600						
70	Oil and Filter Change	30	hour	$ 75.00	$ 2,250						
71	Fuel Filter Change	8	hour	$ 75.00	$ 600						
72	Air Filter Change	5	hour	$ 75.00	$ 375						
73								$ 6,825	$ 568.75	$ 0.0176	
74	Replacement Schedule										
75	Batteries	240	each	$ 720	$ 172,800	3.7	years	$ 46,703	3,891.89	$ 0.1201	
76	Inverter	1	each	$ 130,000	$ 130,000	6	years	$ 21,667	1,805.56	$ 0.0557	
77	Generator	1	each	$ 35,000	$ 35,000	2.7	years	$ 12,963	1,080.25	$ 0.0333	
78	Solar Modules	17	kW	$ 4,000	$ 68,000	20	years	$ 3,400	283.33	$ 0.0087	
79											
80	**Assumptions**				Total O&M Cost			$ 192,130.05	$ 16,010.84	$ 0.49	
81	Genset kW	50	kW								
82	Average Solar Hours/ day	6	hours/day								
83	Solar Array kW	16	kW				Monthly			Capacity Factor	
84	Daily Solar kWh	96	kWh	Solar kW x Daily Hours			2,880	Solar kWh per month		22.8%	
85	Gen Set kWh/day	1,146	kWh	Load plus system losses minus Solar kWh			34,380	Gen Set kWh per month		92.4%	
86	Genset Battery Charging hours	23	hours	Genset kWh / genset kW			37,260				
87	Gallons per Hour fuel consumption	4	gal/Hr	From Cat website specs for new 50kW unit + 25%							
88	Daily Fuel Consumption	92	gal/day								
89	Monthly Fuel Consumption	2750	gal/month								
90	Annual Fuel Consumption	33,005	gal/year								
91											
92											
93											
94				2007	2008	2009	2010	2011			
95		Air Terminal	Residential	Total							
96	Total O&M per Year	$ 123,339.65	$ 192,130.05	$ 315,469.71							
97	Total O&M per month	$ 10,278.30	$ 16,010.84	$ 26,289.14							
98	Total Load kWh per month	18,750	32,400	51,150							
99	Avg $/kWh	0.54818	0.49416	0.51396	0.52938	0.54526	0.56162	0.57847			
100			Escalation Rate -	3.0%							
101											
102		Grand Canyon West			Grand Canyon West						

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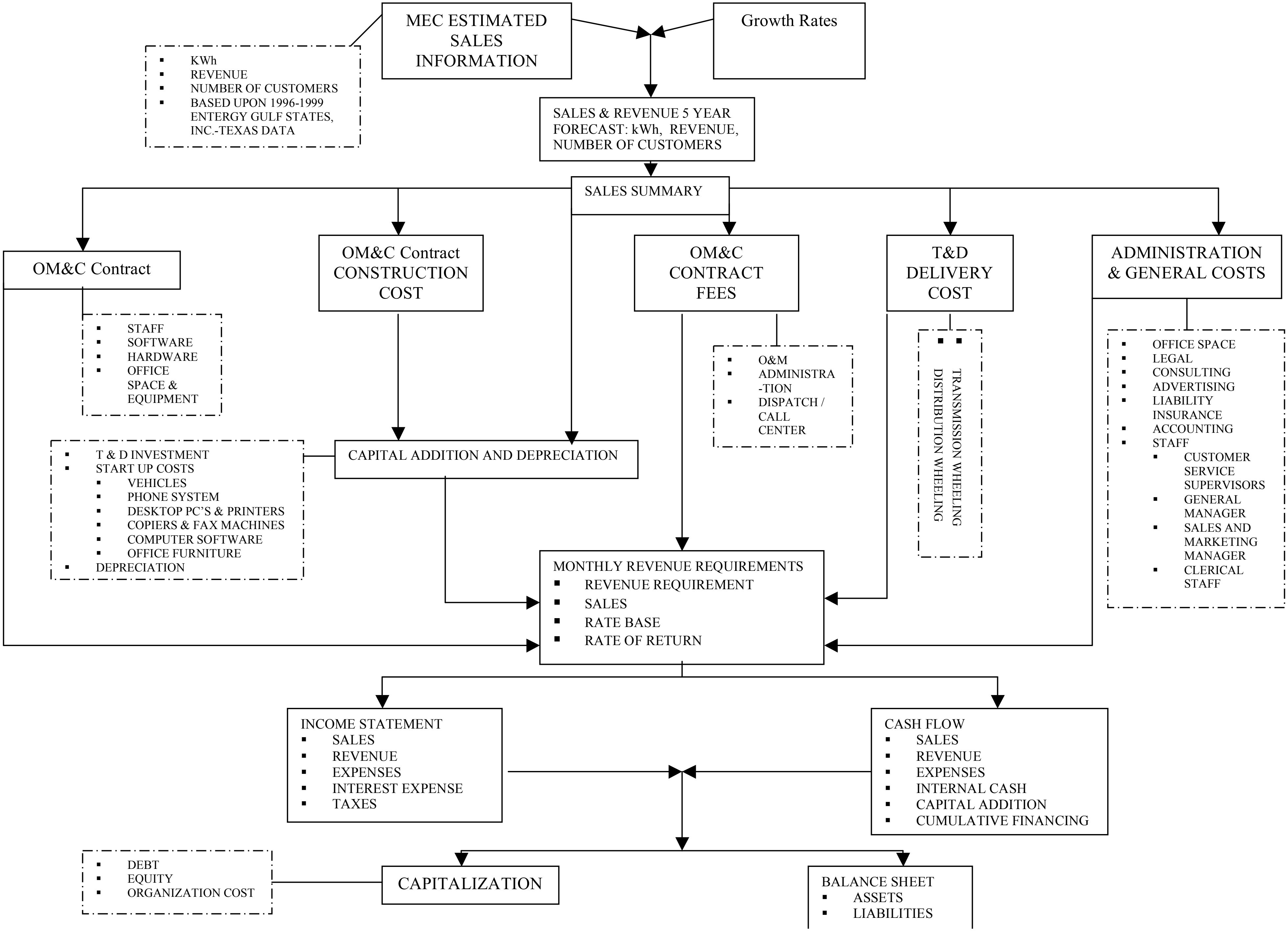
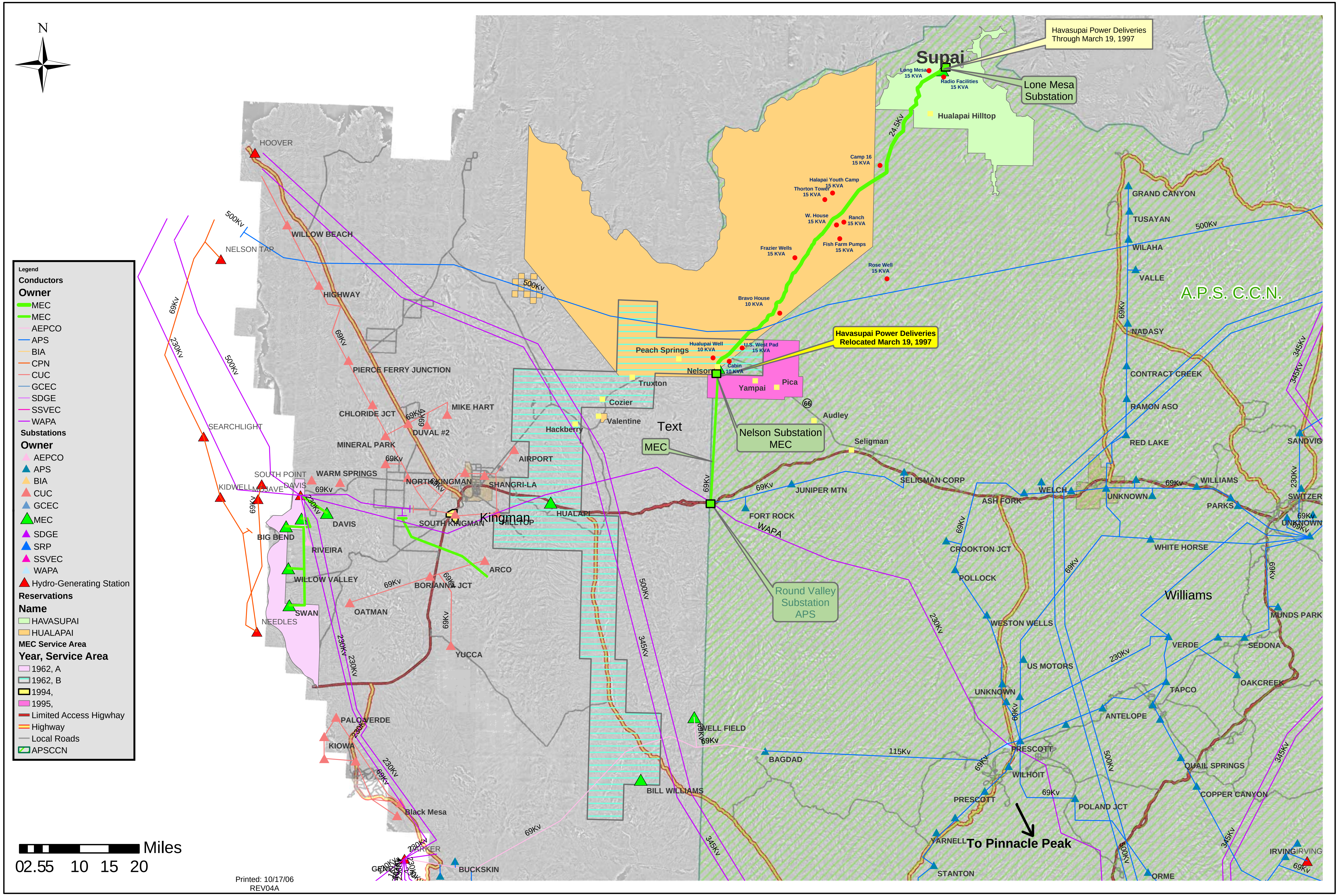
	A	B	C	D	E	F	G	H	I	J	K
103		Estimated Annual Average Operating Cost Including Fuel			Estimated Annual Average Retail Rate						
104		cents/kWh			cents/kWh						
105		**Year**	**cents/kWh**		**Year**	**cents/kWh**					
106		2007	0.51396		2007	0.50600					
107		2008	0.52938		2008	0.52100					
108		2009	0.54526		2009	0.53600					
109		2010	0.56162		2010	0.55100					
110		2011	0.57847		2011	0.56700					
111											

DRAFT

Hualapai Tribe

PROFORMA FLOW DIAGRAM





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