2018 Annual Report for the Hualapai Tribal Utility Authority

Prepared by: Hualapai Tribal Utility Authority Board and
General Manager

Presented to HTUA Board on April 3, 2019

Approved by HTUA Board on April 3, 2019

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Preface

Formation / Mission

Hualapai Tribal Utility Authority (HTUA) has been formed by the Hualapai Council in accordance with Hualapai rules, regulations and ordinances.

The five primary missions for the HTUA as defined by Section 107 of the Ordinance are as follows;

1) Establish and maintain electric power service for Grand Canyon West,

2) Establish and maintain water service for Grand Canyon West,

3) Establish and maintain sewage service for Grand Canyon West,

4) Establish and maintain telecommunications service,

5) Establish and maintain such additional utility services for such other locations within the Hualapai Reservation and on other Tribal lands under the jurisdiction of the Hualapai Tribe as the Tribal Council may deem appropriate pursuant to Section 108 of this Ordinance.

To accomplish these various missions, HTUA is authorized to carry out the following kinds of activities:

(1) To plan for, provide, and furnish electric power, water and wastewater utility services to GCW and provide telecommunication services for the Hualapai Reservation and other Tribal lands under the jurisdiction of the Hualapai Tribe. Such services may include other energy-related services, including energy conservation and the use of renewable energy technologies.

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

(3) To acquire, construct, operate, maintain, promote, and expand electric power service, water service, and wastewater service at GCW as well as acquire, construct, operate, maintain, promote, and expand telecommunications throughout the Hualapai Reservation and on such other locations within the Hualapai Reservation and on other Tribal lands under the jurisdiction of the Hualapai Tribe as the Tribal Council may deem appropriate pursuant to Section 108 of this Ordinance.

(4) To operate utility services so as to provide revenue sufficient to service debt on particular component projects as may be required by creditors on such component projects.

(5) To do everything necessary, proper, and 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 Hualapai Constitution.

Annual Report Requirements

In accordance with Section 110 of the Hualapai Tribal Utility Authority (HTUA) Ordinance, 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;

1) financial conditions,

2) proposed budget for the upcoming fiscal year,

3) rates for various classes of consumers,

4) progress on HTUA's mission, and

5) 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 HTUA. 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 HTUA from taking a planned action, but, if Council approval is required, a supplemental report to the Council (followed by Council approval) shall be required.

I. <u>Executive Summary</u>

HTUA has remained focused on the 5 primary mission goals as set forth in Section 107 of the HTUA Ordinance. During 2018, HTUA has been primarily focused on the development of a radial distribution line and substation to serve the current and the future electrical requirements for Grand Canyon West. HTUA is planning on leveraging the GCW power line to also satisfy its mission of providing telecommunication to GCW by specifying that a multi-strand fiber optic cable be installed as part of the GCW power line. The development process is such that most of 2018 has been spent working with the BLM to identify and evaluate alternative power routes. In June of this year the BLM required that an additional route (Pierce Ferry/Diamond Bar Route) be considered as an alternative route. This is a very time consuming process and we can expect another 6 to 9 months before the BLM makes a determination on its preferred route. With the inclusion of the necessary public hearings and comment periods we are forecasting the earliest construction could begin would be late 2019 or early 2020. HTUA has also been working with consultants on supplying the information required by the BLM as well as preliminary substation, fiber optic cable and power line design work. Additionally, HTUA has been working with TEP/UniSource on an interconnection agreement and a system impact study to determine the nature and cost of improvements to the TEP/Uni Source system to interconnect and accommodate the new power line to GCW. Finally, HTUA has been investigating and identifying potential financing agencies and the loan covenants that will be required to finance the project.

In connection with its work on GCW, the HTUA conducted a <u>cost of service study</u> for GCW and the rest of the Hualapai Reservation. This study investigated the merits and associated cost of service for serving the electrical requirements of GCW and the rest of the Hualapai reservation-primarily Peach Springs today but additionally the HTUA also considered the impact and requirements for the HTUA to serve the future pumping loads associated with the potentially allocated water from the Colorado River. HTUA is working to make sure that any power line development for Grand Canyon West could, at some future date, be integrated or supportive of serving other electrical loads on the Hualapai Tribe's Reservation. The study also investigated where it will obtain the necessary power to serve the GCW electrical requirements and how the power will be delivered to HTUA. HTUA has taken a look at the costs of market power and has identified viable power line paths for delivery of power to GCW. Currently, it looks like GCW electrical load will be delivered thru a combination of Uni-Source and WAPA transmission grids. The actual power will be obtained from the market and perhaps some of the current federal hydro allocations currently allocated to the Hualapai Tribe. The bulk of this work was conducted with the assistance of an outside consultant and is captured within the cost of service study Appendix B of this report. The study concluded that the electrical load on the reservation is not large enough at this time for the HTUA to economically operate an electric utility.

HTUA also investigated the installation of a Community Scale Solar Project to serve the community of Peach Springs. The results of the study appeared favorable however due to the lack of direct access to the regional transmission grid it was determined that the project could not move forward at this time. The only off-taker for excess generation period was Mohave Electric Co-operative. The terms presented by Mohave Electric in its purchase power agreement were unacceptable at this time. The Community Sale Solar study is attached as Appendix C.

II. <u>Mission Related Accomplishments 2018</u>

1) General Manager: Retention of a part time Genera Manager with Engineering and Tribal Utility Management/Operations background

2) Grand Canyon West Radial Distribution Line:

   a) Oversight of preliminary work by surveyor and environmental consultant to stake power line routes and perform the Environmental Assessment (EA) to analyze multiple routes to Grand Canyon West,

   b) Oversight of preliminary work by engineering and financial consultants to assist the HTUA's loan application to USDA/Rural Utilities Service to finance the power line to Grand Canyon West

   c) Oversight of technical interconnection study for the new power line to GCW from Tucson Electric/UniSource with a connection point of Dolan Springs substation located on Pierce Ferry Road

   d) Investigation into surrounding area utilities grids and determination of how the GCW power line could be integrated into regional grid

   e) An understanding how HTUA could possibly provide electric service to the required pumping electric loads for utilization of the anticipated Colorado River water allocation

   f) Discussion with Mohave County regarding the utilization of the Pierce Ferry/Diamond Bar Road as an alternative power line path

   g) Coordination with the BLM's Kingman Field Office regarding the possible use of BLM ROW's for the power line Path

   h) Apply to BIA for an encroachment permit to place the proposed power line within the existing Diamond Bar roadway right-of-way

3.) Cost of Service Study: As a result of a successful application to the BIA's Tribal Energy Development Capacity Grant Program, the tribe was awarded $32,960 to perform a cost of service study. This is a prerequisite to understanding the costs involved to acquire and then operate the local electrical distribution system. The tribe hired Intergroup to perform the cost of service study to review existing customer classifications and load data, conduct preliminary annualized revenue requirements for the

HTUA (unbundled costs, allocation of costs among rate classes, capital additions), recommend rate design and cost of service model, and identify funding sources to finance the electric system. The study also identified the location of Mohave Electric assets in Peach Springs and the cost of said facilities and the identification of permitted and unpermitted ROW's for the existing Mohave Electric assets serving Peach Springs. The study concluded that the electrical load on the reservation is not large enough at this time for the HTUA to economically operate an electric utility.

4.) <u>Community Scale Solar project</u> The tribe was also able to secure a $75,000 grant from the BIA Energy and Mineral Development Program to perform a feasibility study for a community-scale solar array in Peach Springs. Rock Gap Engineering was hired to conduct the feasibility study which will recommend 1) the type of solar technology and design to utilize, 2) the optimum site to locate the solar array based on both location along the existing electric distribution line and land resources, 3) the correct size of the solar array to meet community need while not overloading the local utility's (MEC's) distribution system - via a system impact study, 4) identify funding sources to build the solar array and 5) draft a power purchase agreement which will ensure the project is economically feasible. Rock Gap has performed two field trips, conducted a soils test on two candidate sites, and made two presentations to the HTUA. The sites are promising and the soils can support a 1 MW array; however, the PPA offer from MEC of $25/MWhr prevents the solar project from being economically attractive without a significant subsidy, possibly via a DOE renewable energy grant. The solar site adjacent to the Lhoist mine could be developed as a merchant plant with power sold directly to Lhoist. The results of the study appeared favorable however due to the lack of direct access to the regional transmission grid it was determined that the project could not move forward at this time. The only off-taker for excess generation period was Mohave Electric Co-operative. The terms presented by Mohave Electric in its purchase power agreement were unacceptable at this time. The Community Sale Solar study as attached as Appendix C.

<u>5. HTUA presentation to HTUA Council</u> HTUA provided the Hualapai with a status update on the power line project into GCW. The Hualapai council was also provided with financial forecasts for HTUA (revenue/expenses estimates) based on different scenarios. Specifically revenue and expenses were looked at for the HTUA to provide electric service to; just GCW, GCW and Peach Springs, GCW-Peach Springs –future water pumping needs associated with the anticipated Colorado River water allocation. A copy of that presentation is included in Appendix D.

6.) <u>Telecommunication Related</u> HTUA continue to work with the Hualapai Council on several telecommunication related projects. HTUA in conjunction with the Hualapai Planning Department has recently released a request for proposal for assistance with negotiating a new right of way agreement with AT&T for its fiber optic cable that crosses the Hualapai reservation in certain sections. Tribal council would like to develop its own telecommunications infrastructure and has asked the Planning department to research funding sources on the behalf of the HTUA which would be the entity that is qualified to request and receive such funding.

<u>7.) Meeting with Gila River Indian Community Utility Authority</u> Members of the HTUA Board traveled to the Gila River Indian Reservations to meet with members of their Tribal Utility GRICUA to learn about

their experience with owning and operating a tribal electric utility. During the same visit some HTUA members also attended the Arizona Tribal Energy Association annual meeting.

III. FY 2018 Financial Report thru December 31, 2018

HTUA's operational budget for 2018 as approved by the Hualapai Council was $643,915. As of December 31, 2018 HTUA had expended $293,799 with a balance of budget at $350,116. The surplus is primarily due to longer than expected power line route approval process from the BLM. The $350,116 of unexpended budget funds is still required and has re-budgeting as reflected in the 2019 budget request.

HTUA Budget 2018--Expenditures to Date			
		12/31/2018	
Budget Item Description	***Budget Amount***	***Expenditures to Date***	**Remaining Budget Amount**
General Manager (Part Time Consultant)	**$ 64,824**	**$ 57,117**	**$ 7,707**
Legal Counsel	**$ 90,000**	**$ 17,657**	**$ 72,343**
(GCW) Engineering Consultant (IMEG)	**$ 60,700**	**$ 60,700**	**$ -**
(GCW) Surveyor Consultant (prelim & final)	**$ 175,000**	**$ 83,147**	**$ 91,853**
(GCW)NEPA Consultant	**$ 160,000**	**$ 36,534**	**$ 123,466**
(GCW)USDA Loan Application Consultants	**$ 55,400**	**$ 8,324**	**$ 47,076**
(GCW)Bureau of Land Management	**$ 20,000**	**$ -**	**$ 20,000**
Arizona Power Authority	**$ 7,946**	**$ 9,309**	**$ (1,363)**
Board Member Training & Travel	**$ 5,000**	**$ 3,475**	**$ 1,525**
Arizona Tribal Energy Assoc	**$ 1,500**	**$ 1,394**	**$ 106**
Public Outreach	**$ 3,545**	**$ -**	**$ 3,545**
Misc Unforseen	**$ -**		
anhorwave	**$ -**	**$ 1,394**	**$ (1,394)**
Mohave Electric		**$ 16**	**$ (16)**
Soutwest Courier		**$ 52**	**$ (52)**
Kingman Daily Miner		**$ 151**	**$ (151)**
Uni-source ---System Impact Study for (GCW)		**$ 12,994**	**$ (12,994)**
other professional		**$ 1,536**	**$ (1,536)**
			$ -
			$ -
Total Budget	**$ 643,915**	**$ 293,799**	**$ 350,116**

IV. Mission Goals for 2019

The council has directed HTUA to continue working on a plan to integrate all utilities. HTUA has the following mission related goals for 2019;

- Grand Canyon West Radial Distribution Line(Electric service mission)
    - Complete route alternative route analysis and finalize route selection
    - Secure necessary ROW
    - Complete study work with TEP / Uni-Source
    - Finalize TEP/ Uni-source interconnection agreement
    - Finalize power line and substation design
    - Identify financing options and make a final recommendation to council of a financing plan
    - Identify construction contractors and provide a construction RFP to construct GCW power line
    - Complete construction work plan
    - Complete long range financial plan for HTUA
    - Preliminary work on power supply for GCW
    - Preliminary work on telecommunication interconnection with broad band supplier for GCW

- Telecommunication Related(Telecommunication Service Mission)
    - Focus on improving telecommunications to Peach Springs that will satisfy council directive to provide free internet service (4G LTE) to student.
    - Assist with negotiations on AT&T fiber optic ROW renewal negotiations
    - Work with AT&T to bring a proposal forward to the council that will provide free internet service (4G LTE) to students
    - Seeking funding to establish an HTUA-operated telecommunication system.

- Water and Wastewater Service Goal
    - Continue to work with council on provisioning the pumping and delivery of the anticipated Colorado River water allocation to different areas on the Hualapai reservation
    - Develop a water and wastewater model that quantifies current needs/usage and a forecast of future needs with a primary focus on GCW.

V. Budget request for 2019

HTUA is requesting a budget amount of $899,899 of which over $700,000 is directly attributable to the GCW radial distribution line project.

Proposed HTUA Budget for 2019			Account No.	01-60-00-0000	
General Manager Consulting*	Rate	units/week	weeks	Total	Notes
Labor per Hour	$75.00	22	52	85,800.00	
Lodging per night	$125.00	2	6	1,500.00	
Per Diem	$45.00	0	0	0.00	
Mileage per visit	$0.535	250	12	1,605.00	
				88,905.00	
Legal Counsel	Rate	Units/Month	Months	Total	
Labor per Hour (composite rate)	$425.00	17	12	86,700.00	
Lodging per night	$100.00	2	2	600.00	
Per Diem	$45.00	2	2	180.00	
Mileage per visit	$0.535	400	2	428.00	
Total				87,908.00	
Other professional Services					
Transmission Line Design&Substation				350,000.00	
Survey work				100,000.00	
RUS construction work plan/load forecast				75,000.00	
Environmaental Work				110,000.00	
USDA finacial forecast long range				17,000.00	
				739,908.00	
Bureau of Land Management				**Total**	
Review and Processing Costs				5,000.00	
				5,000.00	
Arizona Power Authority BCP Power	Rate/MWHr	MWhrs/Month	Months	Total	
Capacity	$28.17	15.50	12	2,293.00	
Energy				2,947.00	
Recoverable Capital Advances				1,451.00	
				6,691.00	
Uni-source/Tucson Electric Study work	Tuition/Rate	Units/Students		Total	
Final interconnection design -cost	$50,000.00	1		50,000.00	
				50,000.00	
Board Member Training & Travel	Rate/Mile	Miles		Total	
Automobile	$0.575	3,000		1,725.00	
Per Diem	Rate/Quarter	Rate/Day	Days	Total	
Inside-State Per Diem	$11.25	$45.00	10	450.00	
Outside-State Per Diem	$15.00	$60.00	5	300.00	
Training/Conferences	Tuition/Rate	Units/Students		Total	
Solar Power International	$1,065.00	5		0.00	
Lodging	Room Rate	Nights		Total	
Hotel	$125.00	15		1,875.00	
				4,350.00	
Memberships	Annual Dues			Total	
Arizona Tribal Energy Assoc	$1,500			1,500.00	
				1,500.00	
Public Outreach	Rate/Cost	Units/Month	Months	Total	
Domain Hosting & Web support	$130.00	1	12	1,560.00	
Pamphlets	$0.50	500	1	250.00	
Postage	$1.47	500	1	735.00	
Food	$5.00	200	1	1,000.00	
Supplies				2,000.00	
				3,545.00	
Total Budget				**899,899.00**	

VI. Budget approved for 2019

The Tribal council approved $251,500 of the requested $899,899 as shown below.

HTUA 2019 Budget as Approved by Tribal Council				
Professional Services	**$ 250,000.00**			
Memberships and Subsciptions	**$ 1,500.00**			
	$ 251,500.00			

Appendix A: Meeting minutes from November 22, 2017 thru December 20, 2018

Hualapai Tribal Utility Authority (HTUA) Meeting Minutes

November 22, 2017, 9:12 AM to 11:25 AM, Hualapai Health Department, Peach Springs.

Board members:

Charles Vaughn, Chairman – present at 9:28 AM

Joe Montana, Vice-Chairman – present

Jamie Navenma, Secretary – present at 9:44 AM

Bill Cyr – present via telephone until approx. 10:30 AM

Rory Majenty – present via telephone

Support personnel and guests:

Kevin Davidson, Planning Director

Patrick Bowman, Intergroup (via telephone)

Lauren Ferrigni, Fennemore Craig (via telephone)

Patrick Black, Fennemore Craig (via telephone)

1) Call to Order

2) Roll Call

3) Review and Approval of Minutes from October 18, 2017, meeting

Mr. Montana entertained a motion to approve the meeting minutes of October 18, 2017, as written. Mr. Cyr made a motion to approve the minutes. Mr. Montana seconded the motion. Motion carried 2-0-1.

4) Project Updates

a. Proposed Power Line to Grand Canyon West

i. Update on Council action on draft Interconnect Agreement with UniSource Mr. Davidson reported that Council approved the HTUA's transmittal of the draft Interconnection Agreement (IA) to UniSource at its Special Council Meeting on November 21, 2017. Mr. Cyr asked if

UniSource has reviewed the draft IA and at what stage in the negotiation process is the tribe with UniSource. Ms. Ferrigni said that although UniSource has not yet had an opportunity to review the HTUA's draft Interconnection Agreement, UniSource should be familiar with large portions of the IA because it was drafted based on language that UniSource uses for both its Small and Large Generator Interconnection Agreements (SGIA and LGIA). Mr. Cyr asked if the language in the SGIA and LGIA has been approved by the Federal Energy Regulatory Commission (FERC). Ms. Ferrigni replied that the language has been approved by FERC. Mr. Cyr said he will review the IA in detail. Ms. Ferrigni stated in view that Council has approved the draft IA, it will be forwarded to UniSource to begin the more substantive negotiation process.

ii. **Update on Council action on bids for power line survey, environmental, construction work plan, and long-range financial forecast** Mr. Davidson said Council provisionally awarded contracts to Taney Engineering, T&D Services and Cobb Consulting for the survey, construction work plan and long-range financial forecast, respectively, at the November 4, 2017, Regular Council Meeting. Tierra Right-of-Way was provisionally awarded the environmental assessment contract at the Special Council Meeting on November 21, 2017. All awards are contingent upon Council approving the HTUA's FY 2018 budget. Mr. Majenty asked about Indian preference in the award process since SWCA's proposal included an Indian-owned company. Mr Davidson noted that the points awarded to SWCA in this category were not enough to overcome the points awarded to Tierra Right-of-Way under the cost considerations category.

iii. **Update on Council action on Cost Reimbursement Agreement with BLM** Mr. Davidson said in order for the BLM to process the tribe's SF-299 application for the right-of-way and the Plan of Development (POD), which describes the power line design and construction in detail, the tribe must enter into a cost reimbursement agreement with BLM. Mr. Whitefield has prepared the agreement and estimates the amount to be $33,723. This item was first heard by Council on November 4, 2017, but tabled due to concerns over the appeal process to BLM. Mr. Davidson said Council approved the Cost Reimbursement Agreement at the Special Council Meeting on November 21, 2017, after he explained that the tribe can appeal the decision on the environmental review to the Secretary of the Interior.

b. Cost of Service Study

i. Progress to Date Mr. Bowman gave an overview of the slide show presentation. There has been some delay in receiving the asset data from Mohave Electric Cooperative (MEC), with the last portion being received on November 15, 2017. The cost of service study will provide a revenue requirement and cost of service forecast to understand the feasibility of the Hualapai Tribal Utility Authority (HTUA) purchasing Peach Springs Distribution Assets from MEC to run a local electric distribution utility. The study is nearing completion for the Peach Springs analysis with the rate design step, if required, and report finalization remaining. Mr. Cyr asked should not the study also include Grand Canyon West given the scope of the RFP. Mr. Davidson said the information on electrical load at Grand Canyon West has been delayed due to the late installation of the data card on the generator's switchgear. Mr. Vaughn said the study should also take into account the anticipated electrical load caused by the tribe's pending water rights settlement which will require water to be pumped from the Colorado River up Diamond Creek Road then out to Grand Canyon West, a distance of some 70 miles. The HTUA should also look at purchasing off-reservation power line assets to bring power to the reservation.

Mr. Majenty noted that the electrical loads at Grand Canyon West are less in autumn with the air conditioning units not being used as much as they are in the summer coupled with the fact that the facilities are heated with propane. Peak electrical loads occur during summer. Mr. Cyr opined that including the electrical loads at Grand Canyon West and the electricity to pump the water from the Colorado River in the cost of service study could be the catalyst to make the HTUA a profitable utility.

Mr. Bowman next reviewed the preliminary conclusion (slide 5) in the table below:

	Revenue		**Costs**		***Difference***		**Rate Increase Required**
	$	¢/kWh	$	¢/kWh	***$***	***¢/kWh***	
2017 Estimate (without power supply rate reduction rider)	**828,452**	**10.26**	**1,082,430**	**13.41**	***-253,978***	***-3.15***	**30.7%**
2017 Estimate (with power supply rate reduction rider)	**687,172**	**8.51**	**941,151**	**11.66**	***-253,978***	***-3.15***	**37.0%**
2007 Feasibility (2010 forecast year)	580,403	9.21	709,330	11.25	*-128,927*	*-2.05*	22.2%
2009 Feasibility (2010 forecast year)	834,638	8.72	1,051,889	10.99	*-217,251*	*-2.27*	26.0%

The results indicate that a 31% average rate increase is required for HTUA profitability in Year 1. The increases would 37% if including the 2017 adjustment to rates for reduced power supply costs currently applied to electricity bills by MEC. Mr. Bowman said the HTUA could use power sales at Grand Canyon West to subsidize Peach Springs operations with only a five percent revenue shortfall. Mr. Cyr asked how much the shortfall would be reduced if the HTUA could purchase power at a lower price than MEC on the open market. The HTUA should not be bound by the cost fluctuations that MEC is subject to. The HTUA’s power purchase should be substantially less than what MEC pays for power. For example, a kilowatt of power in the Southwest market can be routinely purchased for less than two cents or less. If the HTUA purchases power on the open market, it would be substantially less than the six to seven cents per kilowatt that MEC is charging the tribe. Mr. Bowman said the HTUA could purchase power for itself but have to pay MEC to wheel it over the cooperative’s power lines to Peach Springs.

Mr. Vaughn asked about the cost of acquiring the MEC electrical distribution system. Mr. Bowman said the estimate is $740,000 which is the original cost less depreciation (OCLD), or “book value,” multiplied by 1.5 which seems to be a common multiplier to purchase depreciated assets. However, purchasing power is the biggest single cost for the HTUA at approximately $490,000 per year. Operating and maintaining (O&M) the distribution system is estimated at $96,000 annually. Administrative and general costs are estimated at $150,000 per year. This cost has been inferred from 2007 and 2009 feasibility studies performed by the tribe. Likewise, the $155,000 annual cost of replacing electrical distribution system assets is based on the age of the system derived from the 2007 and 2009 studies. Annual debt service, such as securing a RUS/USDA loan to purchase the system from MEC is estimated at $50,000 (20 year loan at 3% interest rate, maturing in 2038). These costs add up to a $941,000 annual budget. The 2009 study estimated it would require three cents per kilowatt sold to operate the HTUA; today the estimate to operate the HTUA is 5.3 cent per kilowatt sold.

Mr. Vaughn noted that MEC may use its off-reservation assets that the tribe depends upon for wheeling power to the community as well as delivering power to users beyond the reservation on Route 18 as leverage in the buy-out negotiations. Mr. Davidson asked if MEC is likely to require the tribe to purchase that portion of the 70-mile line that passes through the reservation and then serves Long Mesa and the Havasupai Indian Reservation. Mr. Cyr noted that when

Aha-Macav Power System (AMPS) purchased electrical distribution assets in Needles, California, Southern California Edison negotiated the sale of these assets to AMPS.

Mr. Cyr asked if the tribe has a record of the easements that MEC has on the reservation. Mr. Navenma advised the HTUA contact BIA's Realty Division to obtain these records. Mr. Davidson said he has requested these records from Ms. Varela, Realty Specialist for the Southern Paiute and Truxton Caňon Agencies.

In regard to the OCLD of $740,000, Mr. Cyr said the HTUA may be able to make a better deal and get the number closer to the "book value" (see table).

		2017 MEC Data	2007 Valuation Acc. Depreciation Weighting		
Code	**Distribution Asset Category**	**Quantity (#)**	**Gross Book Value ($)**	**Estimated Accumulated Depreciation (2007 Report %)**	**Estimated Net Book Value (OCLD)**
364	Poles, Towers & Fixtures	1,752	$ 552,337	$ 460,653	**$ 91,684**
365	Overhead Conductors & Devices	2,297,751	$ 1,448,783	$ 1,287,806	**$ 160,976**
366	Underground Conduits	2,280	$ 2,597	$ 519	**$ 2,077**
367	Underground Conductors & Devices		$ -	$ -	**$ -**
368	Transformers	312	$ 457,610	$ 370,446	**$ 87,164**
369	Services	3,391	$ 304,073	$ 202,715	**$ 101,358**
370	Meters	505	$ 134,102	$ 89,400	**$ 44,701**
373	Street Lighting & Signal System	35	$ 8,906	$ 3,563	**$ 5,344**
	Total	**2,306,026**	**$ 2,908,407**	**$ 2,415,102**	**$ 493,304**

Mr. Navenma asked if the system will be assessed during the negotiations with MEC. Mr. Bowman said the 2007 assessment was fairly complete, with most of the assets now being 10 years older. Mr. Navenma asked if MEC is replacing wood poles with steel. Mr. Davidson said the recent permits he has reviewed are using wood poles. Mr. Davidson asked if the assumed RUS/USDA loan amount is subject to a similar loan to value ratio as that of a home loan, typically 85% of the appraised value. Mr. Bowman said the loan would be based on the HTUA's ability to pay instead of asset valuation. Mr. Bowman added that replacing three percent of the assets per year is just ahead of annual system depreciation. To reduce annual debt service, the HTUA could opt for a 30-year term loan from RUS/USDA that reduces annual payment to $38,000.

Mr. Bowman next reviewed slide 14 which shows that comparable utilities have per-customer O&M costs of two to three times of the HTUA estimate of $685 per year. Mr. Bowman said if the HTUA uses MEC as a third-party to purchase energy or instead purchases directly from Arizona Electric Power Cooperative Inc. (AEPCO), Western or APS, power supply costs will likely be higher due to increased transmission charges (charged by MEC or other third parties to transfer energy that is currently included in rates paid to MEC). This does not include additional transmission charges that MEC may charge, which could further increase power supply costs. Including Grand Canyon West in the cost of service study will help reduce the HTUA's operational costs.

Mr. Bowman concluded his presentation by listing next steps as follows: 1) Review revised data from MEC which could adjust asset replacement and acquisition estimates; do not expect material changes to conclusions, 2) Consideration for included/excluded assets and acquisition negotiated price, 3) Rate design considerations if warranted, such as approach to rate increases, 4) Further discussion on electricity reliability issues, and 5) Review Grand Canyon West needs. Mr. Cyr thanked Mr. Bowman for his good analysis.

c. Community-Scale Solar Array Feasibility Study

i. Progress to Date Mr. Davidson briefly reviewed soils report prepared by Rock Gap's subcontractor – ATEK Engineering. The soils are adequate for a solar array. Mr. Montana asked at what depth the drill reached "refusal." Mr. Davidson referred to the soils logs (hollow stem auger refusal between 5' and 14' below grade). The next step is to negotiate a PPA with MEC. The team should include members of the HTUA Board. Mr. Davidson will contact Mr. Mason for his availability to meet with MEC as well.

To make the solar array a reality, Mr. Davidson referred to the grant notice of intent from the Department of Energy (DOE) which offers up to $1 million for energy infrastructure deployment on tribal lands such as constructing a community-scale array. The tribe will use the feasibility study prepared by Rock Gap as part of the grant application to the DOE.

d. Community Wi-Fi

i. Documentation on AT&T right-of-way on Hualapai Reservation Mr. Davidson said he contacted Mr. Luis Ortega of AT&T's Right-of-Way Division and was able to obtain more complete information on the rights-of-way granted by tribal Resolution Nos. 36-63 and 09-89 to AT&T to place the co-axial and then fiber optic cables, respectively; however, neither document contains the BIA approval of the right-of-way. AT&T made an offer of 50 years beginning on March 21, 1963, so the right-of-way may have expired in 2014.

ii. **Investigation by BIA into right-of-way lease terms** Given the incomplete information, Mr. Davidson has asked Ms. Varela of BIA Realty make a second inquiry with AT&T requesting the documents. Ms. Varela is also searching for the companion set of rights-of-way approvals that the BIA should have on file.

5) Review of FY 2017 Budget and FY 2018 Budget Request (Planning)

a. **Consideration and possible action on budget amendment** Mr. Davidson reviewed the proposed HTUA budget for 2018 with funds set aside for a General Manager ($64,824) legal counsel ($90,000), engineering consultants ($351,100),and training for linemen apprenticeship program ($20,000). The Finance Department asked for the budgets early this year so the draft budget showing a total request of $668,015.04 was submitted on October 13, 2017. Mr. Vaughn made a motion to approve the HTUA FY 2018 budget. Mr. Mr. Navenma seconded the motion. Motion approved 3-0-0-2 (Mr. Cyr and Mr. Majenty had left the meeting).

b. **Update on hearing with Budget Committee** Mr. Davidson said that budget committee has yet to meet with the various tribal departments, but should in the next few weeks.

6) Other Matters (Planning)

a. **Review of WAPA Contract 17-SLC-0817 and potential benefit partners** Mr. Vaughn said the contract was redundant and overly verbose. Mr. Black said it is modeled after the 2004 contract which may not be as streamlined as the more recent WAPA contract for the Boulder Canyon Project. Mr. Black added that unlike the Boulder Canyon Electric Service Contract, there is no mention of special dealings with the tribes' sovereign immunity. Mr. Vaughn said there is no guarantee that WAPA will deliver power to the tribes or other power customers which could be a real issue with future water shortages predicted in the Colorado River system. Mr. Davidson added that electricity generation is a third level priority for the Bureau of Reclamation with flood control and water delivery to agricultural, municipal and industrial users having a higher priority. Mr. Black said the power allocation to the tribe is a relatively small benefit, being part of an arrangement with a third-party utility company, and not critical to the tribe's operations. Mr. Vaughn made a motion to submit the contract to tribal council for approval. Mr. Montana seconded the motion. Motion approved 3-0-0-2.

b. **Review and possible action on draft 2017 Annual Report to Tribal Council per Section 110, HTUA Ordinance** Mr. Davidson reviewed the 2017 annual report noting the highlights of amending the HTUA Ordinance to allow for telecommunications and selecting consultants to help design and permit the power line to Grand Canyon West. Mr. Vaughn made a motion to approve the 2017 Annual Report. Mr. Navenma seconded the motion. Motion approved 4-0-0-1 with Majenty returning to the meeting.

c. **Election of Board Officers (Section 205, HTUA Ordinance)** Mr. Montana nominated Mr. Vaughn to be Chairman, seconded by Mr. Majenty; nomination approved 4-0-0-1. Mr. Vaughn nominated Mr. Montana be retained as Vice-Chairman and that Mr. Navenma be retained as Secretary, seconded by Mr. Majenty; nominations approved 4-0-0-1. Mr. Majenty nominated Mr. Cyr to be Treasurer, seconded by Mr. Vaughn; nomination approved 4-0-0-1.

d. **Discuss field trip to Gila River Indian Community Utility Authority** Mr. Cyr said it would benefit the HTUA Board to visit another tribal utility in Arizona to understand how they are handling similar issues with rights-of-way, purchasing power, etc. Mr. Davidson said he would contact Mr. Leonard Gold, General Manager for the Gila River Indian Community Utility Authority, and set up a meeting possibly in conjunction with the upcoming annual Arizona Tribal Energy Association conference on January 25-26, 2018, in Phoenix.

e. **Announcements** Mr. Vaughn asked about the location for the new tribal administration office. Mr. Davidson said there are 15 locations under consideration including one across the highway from the Indian Health Services clinic.

7) Set time and location for next meeting The next meeting was tentatively set for Wednesday, December 13, 2017, at 9:00 AM at the Hualapai Health Department, Peach Springs, pending availability of Mr. Cyr and Mr. Majenty.

8) Adjourned at 11:25 AM

Hualapai Tribal Utility Authority (HTUA) Meeting Minutes

December 13, 2017, 9:15 AM to 10:13 AM, Hualapai Health Department, Peach Springs.

Board members:

Charles Vaughn, Chairman – present

Joe Montana, Vice-Chairman – present

Jamie Navenma, Secretary – absent

Bill Cyr – present via telephone

Rory Majenty – absent

Support personnel and guests:

Kevin Davidson, Planning Director

Lauren Ferrigni, Fennemore Craig (via telephone)

Patrick Black, Fennemore Craig (via telephone)

Bob Becherer, IMEG (via telephone)

1) Call to Order

2) Roll Call

3) Review and Approval of Minutes from November 22, 2017, meeting

Mr. Cyr made a motion to approve the meeting minutes of November 22, 2017, as written. Mr. Montana seconded the motion. Motion carried 3-0-2.

4) Project Updates

a. Proposed Power Line to Grand Canyon West

i. Comments from UniSource on Interconnection Agreement Mr. Davidson reported that the draft Interconnect Agreement (IA) was transmitted to UniSource on November 27, 2017. Mr. Black said he has been in contact with UniSource's legal counsel but no comments have yet been received. Mr. Black noted that comments from UniSource may not be forthcoming until after the first of the year.

ii. **Status of contracts with prospective consultants** Mr. Davidson said he sent draft contracts last week to Taney Engineering, Tierra Right-of-Way, T&D Services+Q-Spec and Cobb Consulting for the survey, environmental review, construction work plan and long-range financial forecast, respectively, and has heard from the first three firms who are reviewing the language. Ideally, the four contracts will be ready for signature upon approval of the HTUA's FY2018 budget by tribal council in December 2017 so work can begin in late 2017.

iii. **Draft letter to private property owners along power line route** Mr. Davidson referred to the two letters in the agenda packet, the first addressed to Leonard Mardian, Pierce Ferry, LLC and the second addressed to James Rhodes, EB Acquisitions, LLC. The letters seek permission from both land owners to allow the HTUA's surveyor and environmental consultant to access the property for several hours each on two separate days in January of 2018 to conduct their reconnaissance. The letter is for Chairman Vaughn's signature with questions directed to Mr. Davidson. To conclude, the letters provide a signature line for Mr. Mardian and Mr. Rhodes to agree to the access request. Attached to the letter are two maps showing the common property corners and a detail map showing an area of 10,000 square feet that will be crossed. Mr. Davidson said this area allows for a 100-foot wide power line easement on each property in case one land owner refuses the HTUA's request. The letters met with approval of the HTUA Board by consensus and Mr. Vaughn agreed to sign both.

iv. **Hearing with Budget Committee** Mr. Davidson informed the Board that the HTUA's FY 2018 budget hearing with the Budget Committee will be on December 19th beginning at 10:00 AM and encouraged interested board members to attend to lend support for the HTUA's request. Mr. Vaughn asked about the make up the Budget Committee. Mr. Davidson replied the Chairman, Vice-Chairman, Finance Director and Grants & Contracts Officer are on the Committee; however, Council Members Bravo, S.M. Crozier and Havatone have shown an interest in the hearings in general and may attend one or more of the 24 sessions over the two-day period.

b. Cost of Service Study

i. Progress to Date Mr. Davidson referenced the revised 19-page study which incorporates the latest asset data from Mohave Electric Cooperative (MEC) received on November 15, 2017. The Cost of Service study will provide a revenue requirement and cost of service forecast to understand the feasibility of the HTUA purchasing Peach Springs electrical distribution assets from MEC to run a local electric distribution utility. The study shows a $247,000 annual deficit ($924,000 annual operations subtracted from $687,000 annual revenue) if the HTUA where to operate the utility grid in Peach Springs and not raise existing electric rates by some 30% to make up for the revenue shortfall. Intergroup is including the loads anticipated with the water rights settlement – some 8.9 MWs of additional load between the pumping stations along the pipeline route and some 5 MWs at Grand Canyon West for the water purification system. These new loads could eliminate the revenue shortfall if the KWhr charge for these new users is raised by 1.91 cents per KWhr.

Mr. Vaughn added that the water rights settlement bill S1770 is making progress with the US Senate Committee on Indian Affairs. However, the only route presented in S1770 is the Diamond Creek option which is the most expensive to construct and operate. Other, less expensive options, should be explored as well. Mr. Davidson noted the 2014 study produced by DOWL-HKM which did look at other options, but not in as much detail.

To conclude, Mr. Davidson said that Intergroup would be amendable to having Mr. Cyr join in on Cost of Service study effort. Mr. Cyr said he would be happy to help. By consensus, the HTUA Board agreed to have Mr. Cyr participate in the finalization of the Cost of Service study.

c. Community-Scale Solar Array Feasibility Study

i. Progress to Date and next steps Mr. Davidson briefly reviewed the update e-mail from Mr. Mason as follows: 1) Final report detailing construction and design parameters are being finalized and will bring draft copy for our meeting with MEC, 2) Meeting with MEC on December the 20th to discuss a Power Purchase Agreement (PPA) for the off take of solar array production of electricity, 3) Expected completion of study after MEC meeting with final analysis and proposal should be the end of January, 4) Discussion with MEC and Tribe to negotiate a price per watt and a escalation provisions over a 25 year life of the project.

ii. Meeting with MEC on Power Purchase Agreement Mr. Davidson said the meeting with MEC will be on December 20th beginning at 2:00 PM at the Health Department. The PPA offer from the tribe to MEC will start at \$60/MWhr which is likely to be countered by an MEC offer of \$30/MWhr based on conversations with MEC representatives in June of this year. Mr. Davidson said if we could get the MEC offer in writing at \$30/MWhr it could be used as grist in the pending DOE application as to why the tribe needs the federal funding to make the solar array financially feasible (the Department of Energy offers up to \$1 million for energy infrastructure deployment on tribal lands such as constructing a community-scale array). Mr. Cyr advised the PPA between the tribe and MEC should have an “off-ramp” or termination clause in case the HTUA decides to buy out the MEC distribution system on the reservation. This will ensure that the solar array will not have to continue to supply MEC with electricity for what would now be an off-reservation use.

Mr. Vaughn asked about the benefit of the solar power to Peach Springs. Mr. Davidson said the site location at the Burlington Northern and Santa Fe railroad’s West Peach Springs signal can easily be connected to the 3-phase power line that crosses Highway 66 just west of Mile Post 102 and then can feed both the Buck and Doe community to the west and the Peach Springs community to the east.

d. Community Wi-Fi

i. Update on BIA’s investigation into AT&T’s coaxial cable and fiber optic right-of-way lease terms Given the incomplete information the tribe has on file for the lease, Ms. Varela of BIA Realty has also contacted Mr. Luis Ortega of AT&T’s Right-of-Way Division and requested the lease documents. The information on the rights-of-way granted by tribal Resolution Nos. 36-63 and 09-89 to AT&T to place the co-axial and then fiber optic cables, respectively, do not contain the BIA approval of the right-of-way. Mr. Vaughn asked about the difference between coaxial and fiber optic technology. Mr. Davidson explained that the coaxial cable is akin to those used for audio speakers or cable TV while a fiber optic line uses light to transmit the signal. AT&T made an offer of 50 years beginning on March 21, 1964, so the right-of-way may have expired in 2014.

As discussed in a previous meeting, it would be wise to understand the easement situation with AT&T prior becoming a customer and determining a tap point on the fiber optic line for the tribe's use. Mr. Cyr asked if the tribe could re-sale the service to other tribal users and possibly displace Frontier Communications. Mr. Davidson said that may be possible, however, AT&T does not recognize the HTUA as a competitive local exchange carrier (CLEC); only Frontier has CLEC status on the Hualapai Reservation. Another obstacle to the connection is the tribe's end use point, preferably the tribal office. The council is considering a new location for an expanded administration building so the end point location has not yet been determined. The fiber optic line does have access points every few miles along the route, so the tap location may be shifted. Mr. Vaughn asked how long the AT&T line is on the reservation. Mr. Davidson said it is about 18 miles long (17.46 miles) and lies along the north side of Highway 66.

e. Mohave Electric Cooperative

i. Rights-of-Way on Record with BIA Mr. Davidson referred to two tables showing grants of easements for power line rights-of-way recorded with the BIA and those not recorded with BIA. Mr. Cyr asked the difference between the two data sets because BIA seems to have a record of both. Mr. Davidson said those easements recorded have a complete set of documentation behind them while those not recorded have only partial information such an application from MEC and possibly a tribal resolution but not a final, signed grant of easement. The table of recorded easements also shows that several have expired or are nearing the end of their term. The negotiation with MEC for renewal of these easements may play a role in the acquisition of MEC's electrical distribution assets on the reservation.

Mr. Vaughn asked about the power line serving the Mountain Bell repeater station. It appears to be on Grey Mountain. For the unrecorded easements, the service line to a private home in Section 24, T25N, R10W appears to be outside of the reservation boundary. This line may have been a direct request to MEC by the land owner and done outside of the BIA process.

ii. **Request to MEC to provide additional records of rights-of-way not on file with BIA** Mr. Cyr advised the letter to MEC not include the tables of the recorded and un-recorded grants of easement so MEC will be obligated to provide their complete set of records. Mr. Vaughn said references to the tables and maps should be deleted from the letter. The Board agreed by consensus to direct Mr. Davidson to send the revised request letter for grants of easement to MEC.

5) Other Matters (Planning)

a. **Set-up field trip to Gila River Indian Community Utility Authority** Mr. Davidson reported that Mr. Leonard Gold, General Manager for the Gila River Indian Community Utility Authority (GRICUA), can arrange for his board meet with the HTUA board on January 24th between 9:00 AM and 11:00 AM. This meeting can be done in conjunction with the upcoming annual Arizona Tribal Energy Association (ATEA) conference in Phoenix on the following day. Mr. Cyr advised we meet with GRICUA to discuss general topics and then have a separate meeting with Mr. Gold to discuss more specific and also his experience with the Ak-Chin Electric Utility Authority. Mr. Vaughn and Mr. Cyr said they were likely to meet with GRICUA and Mr. Gold, but not attend the ATEA conference. Mr. Montana will check his calendar. Mr. Davidson said he would ask board members Navenma and Majenty on their participation.

b. **Announcements** Merry Christmas! No other announcements.

6) Set time and location for next meeting Mr. Cyr asked if a January meeting is needed. Mr. Davidson said nothing is pressing; however, he would like to report on the status of the two feasibility studies and whether or not tribal council has approved the full budget request for the HTUA. The next meeting is set for Wednesday, January 10, 2018, at 9:00 AM at the Hualapai Health Department, Peach Springs.

7) Adjourned at 10:13 AM

Hualapai Tribal Utility Authority (HTUA) Meeting Minutes

January 10, 2018, 9:38 AM to 10:55 AM, Hualapai Health Department, Peach Springs.

Board members:

Charles Vaughn, Chairman – present

Joe Montana, Vice-Chairman – absent

Jamie Navenma, Secretary – present

Bill Cyr – present via telephone

Rory Majenty – absent

Support personnel and guests:

Kevin Davidson, Planning Director

Lauren Ferrigni, Fennemore Craig (via telephone)

Patrick Black, Fennemore Craig (via telephone)

Bob Becherer, IMEG (via telephone)

1) Call to Order

2) Roll Call

3) Review and Approval of Minutes from December 13, 2017, meeting

Mr. Vaughn made a motion to approve the meeting minutes of December 13, 2017, with minor corrections. Mr. Navenma seconded the motion. Motion carried 3-0-2.

4) FY 2018 Budget Review Mr. Davidson noted that $20,000 was taken from the Training line item that was reserved for linemen training and $4,100 was removed from the Travel fund leaving $5,000 in that line item. With these two items notwithstanding, the HTUA's budget was approved as presented in the total amount of $643,915.04 which will cover the anticipated professional service requests and the expense of hiring a part-time general manager for the HTUA.

5) Project Updates

a. **Proposed Power Line to Grand Canyon West**

i. **Comments from UniSource on Interconnection Agreement** Mr. Davidson reported that the draft Interconnect Agreement (IA) was transmitted to UniSource on November 27, 2017, and that Mr. Matt Bailey, Corporate Counsel for Tucson Electric Power Company (TEP) responded on January 9, 2018, via e-mail, indicating that he has circulated the HTUA's request through TEP's Transmission Planning Group and is awaiting a reply which will most likely include a step by step process and a formal application form for the HTUA to complete along with the name of TEP's contact. Ms. Ferrigni confirmed that TEP is working on a formal response to the HTUA detailing the overall interconnect process.

ii. **Status of contracts with consultants** Mr. Davidson said that he received signed contracts from Taney Engineering, Tierra Right-of-Way, T&D Services+Q-Spec and Cobb Consulting for the survey, environmental review, construction work plan and long-range financial forecast, respectively, and that all were given to the tribe's Grants and Contracts officer on December 28, 2017, for review and signature. Mr. Davidson said he will check on their status after today's meeting.

iii. **Kick-off meeting with consultants** Mr. Davidson said he will schedule a kick-off meeting shortly after the four contracts are signed. On a related topic, Mr. Vaughn asked how the Grand Canyon West Ranch is proceeding on getting grid power to their facility on Diamond Bar Road, some six miles east of Pierce Ferry Road. Mr. Becherer said he has talked to the new owners who acquired the property from Mr. Tuner and said the cost to extend a power line to the site is quite expensive. Mr. Vaughn said an investment by Grand Canyon West Ranch to build a power line part way along Diamond Bar Road could help the tribe to bring power to Grand Canyon West. Mr. Becherer said the cost to build a power line from Pierce Ferry Road to the Grand Canyon West Ranch is estimated to be between $1.5 and $2.0 million. Mr. Becherer said even if the Grand Canyon West Ranch was to pay this part of the cost, the HTUA's proposed power line along Tenny Ranch Road would still cost less to construct. Mr. Vaughn asked about the probability of either UniSource or BLM opposing the Tenny Ranch Road route. Mr. Becherer said UniSource should not have any issues with the route since they will not be owning or operating the power line. Mr. Davidson commented that one of the bidders for the environmental review said this project did not appear to be complex or controversial. Mr. Becherer added the BLM did not indicate any significant issues with the project during the right-of-way application process (SF299).

b. Cost of Service Study

i. Progress to Date Mr. Davidson referenced the e-mail from Ms. Davies of Intergroup detailing the teleconference with Mr. Cyr, Mr. Davidson and Intergroup to help the Cost of Service study focus on reducing power costs to the HTUA. As a result, Mr. Davidson has assembled the tribe's existing hydropower contracts, which are currently subject to a bill credit or benefit arrangement with a third-party utility, such at Navajo Tribal Utility Authority, and presented the data to Intergroup for analysis (see table). The existing hydropower contracts can provide nearly 40 percent of the current power demand in Peach Springs. Intergroup will calculate the cost of the remaining power supply needed to meet demand by time of day which may vary from as low as $5.00/MWhr up to $30.00/MWhr.

Operating Year 2018 Estimated Power Costs

Supplier	*KW/ Contract*	*KW/ Actual*	*KWHrs/ Contract*	*KWHrs/ Actual (AHP)*	*Total Power Costs OY2018*	*Delivery Point*	*Term*	*Notes*
Boulder Canyon Project, Western Sched D1 Summer (est in red)	382	242	583,160	370,000	$13,007.95	Mead 230KV bus	9/30/2067	Benefit Arrangment with Pechanga for 10 yrs. Termination prior to 10/1/2022 w/ penalty.
Boulder Canyon Project, Western Sched D1 Winter (est in red)	382	518	250,495	340,000	$12,408.55	Mead 230KV bus	9/30/2067	Benefit Arrangment with Pechanga for 10 yrs. Termination prior to 10/1/2022 w/ penalty.
Boulder Canyon Project, APA Sched D2	107	67	233,457	184,431	$7,918.67	Mead 230KV bus	9/30/2067	Have signed Bill Credit with MEC. May terminate w/ 30-days notice
Colorado River Storage Project, Western Summer	625	318	1,118,127	1,199,903	$34,051.82	Pinnacle Peak sub (230KV)	9/30/2024 & 9/30/2057	Existing contract in effect with NTUA until 9/30/2024. May terminate w/ 1 year notice
Colorado River Storage Project, Western Winter	609	351	1,163,130	1,163,130	$33,106.27	Pinnacle Peak sub (230KV)	9/30/2024 & 9/30/2057	Existing contract in effect with NTUA until 9/30/2024. May terminate w/ 1 year notice
Total or Avg KW Capacity	**1,106**	**782**	**3,348,369**	**3,257,464**	**$100,493.26**			

Mr. Davidson reviewed a set of tables obtained from Western showing the wheeling rates for the Boulder Canyon, Parker-Davis and other Western projects in the Desert Southwest Region. Intergroup will also research wheeling rates to bring electricity to the reservation, namely through Western's and Mohave Electric Cooperative's (MEC) grid.

On the topic of reliability, Mr. Davidson has acquired additional outage information on MEC's feeder lines from the Kingman, Round Valley and Nelson substations. Mr. Vaughn asked how the HTUA can improve reliability of the off-reservation transmission lines to take advantage of these low cost hydropower allocations. Mr. Cyr said the HTUA requires more information on the type and cause of the power outages, e.g. failures along the transmission and distribution lines as well as at the points of service. Some of the long duration outages may be caused by MEC not having enough staff available to respond immediately to the situation. Having additional linemen on MEC's staff may shorten repair times and restore power sooner to the customers. Mr. Vaughn estimated that MEC will still need at least 90 minutes to access the Round Valley substation and transmission line from their base of operations in Kingman. Mr. Cyr said showing evidence of substandard reliability by the existing transmission providers can be used to obtain funding from Western to improve reliability, i.e. transmission to the Hualapai Reservation. Mr. Vaughn asked that the circuit codes (68, 79, 80 and 81) from each feeder be identified to understand what loads they serve.[1] Also, how is "cut off" defined? Mr. Becherer said this is another name for an electrical switch. Mr. Vaughn asked what the cost would be to each tribal member to improve reliability of power service.

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c. Community Wi-Fi

i. Update on BIA's investigation into AT&T's coaxial cable and fiber optic right-of-way lease terms Given the incomplete information the tribe has on file for the lease, Ms. Varela of BIA Realty has also contacted Mr. Luis Ortega of AT&T's Right-of-Way Division and requested the lease documents. No additional information has been received from AT&T, so the tribe's next step should be to request a formal meeting with AT&T to discuss the contents of the existing lease.

d. Mohave Electric Cooperative

i. Request to MEC to provide records of rights-of-way not on file with BIA Mr. Davidson reviewed the letter sent to MEC in December requesting the records the Cooperative has on file for the grants of easements it has on the reservation. In response, MEC has requested a payment of $784.00 to perform a records search and transmit the information to the HTUA.

ii. Possible action to approve payment to MEC to provide additional records to HTUA Mr. Davidson requested the HTUA Board to approve the use of HTUA funds to pay MEC for these

[1] Circuit 68 serves areas west of the Chinatown switch including Buck & Doe, Music Mountain and VORTAC; Circuit 79 serves a property east of the reservation; Circuit 80 serves Peach Springs east of the Chinatown switch and along Nelson Road; Circuit 81 serves Havasupai and other points along the 70-mile line including the Youth Camp.

records. Mr. Vaughn requested that the inquiry be worded so that the tribe will not be getting records which do not pertain to the tribe. This may lower the cost of the invoice. Mr. Cyr made a motion to approve the expense using HTUA funds. Mr. Navenma seconded the motion. Motion approved 2-1-2.

6) Other Matters (Planning)

a. **Review and possible action on draft RFP for HTUA General Manager position** Mr. Davidson reviewed the draft RFP and noted that much of the scope has been taken from other job descriptions for electric utility general managers. The RFP follows the same outline as other RFPs issued by the Planning Department. Mr. Vaughn noted a spelling mistake and asked if the summary of the job description could be summarized. Mr. Cyr said the RFP reads okay. By consensus, the HTUA approved the RFP subject to a spell check.

b. **Set-up field trip to Gila River Indian Community Utility Authority** Mr. Davidson reported that Mr. Leonard Gold, General Manager for the Gila River Indian Community Utility Authority (GRICUA), has arranged for his board to meet with the HTUA board on January 24th at 9:30 AM. Mr. Vaughn, Mr. Navenma and Mr. Cyr said they will attend the meeting. Mr. Davidson said he will ask Mr. Montana if he can attend as well. Mr. Cyr stressed the importance of having Hualapai Tribal members on the HTUA Board meet with GRICUA. Mr. Vaughn and Mr. Cyr said they will not be attending the Arizona Tribal Energy Association meeting the following day in Phoenix. Mr. Navenma said he would be attending both meetings. Mr. Davidson will prepare travel requests accordingly and said Mr. Majenty will not be able to attend either meeting. Mr. Cyr will prepare a set of technical questions to present to GRICUA.

c. **Announcements** Happy New Year! No other announcements.

7) Set time and location for next meeting The next meeting is set for Wednesday, February 14, 2018, at 9:00 AM at the Hualapai Health Department, Peach Springs.

8) Adjourned at 10:55 AM

Hualapai Tribal Utility Authority Board Meeting

January 24, 2018

Gila River Indian Community Utility Authority, 6636 W. Sundust Rd, Chandler, Arizona

9:30 AM

1) Call to Order
2) Roll Call, Charlie Vaughn, Jamie Navenma and Bill Cyr in attendance for HTUA.
3) Open discussion with Gila River Indian Community Utility Authority on its operations
   a. Overview of GRIC – 17 member council. GRICUA Board is appointed by tribal council. There are some 24,000 GRIC tribal members. Board members must sign an affidavit of no-conflict of interest. Applications for board membership are advertised for 60-days. Selection committee makes recommendations to tribal council. Board members are not term limited. Board members may serve beyond their three-year term if re-appointment or new appointments are not made in a timely fashion.
   b. GRIC is the most fractionated tribe in the USA with several hundred allotments within the boundary of the reservation. This has caused difficulty for GRICUA to extend power lines, with some lines having to by-pass allotment owners who are not willing to allow an easement over the land. By contrast, the Hualapai have a few in-holdings within the reservation and three allotted parcels off-reservation in the Big Sandy Valley (Hwy 93).
   c. GRICUA began in the 1990s by working with San Carlos Irrigation Project (SCIP), a federally operated electric system, with reliability issues and seen as slow to respond to the tribe's needs. GRICUA first began serving new commercial loads on the reservation that SCIP could not serve such as the new casino. By serving only new customers, GRICUA was able to charge higher rates than to existing residential customers. The higher rates also include wheeling charges from Salt River Project and Western. Over the years, GRICUA has proved their ability to run a utility and has gained trust with SCIP to help maintain their electrical system on the reservation as well. The maintenance of these lines is performed via a PL93-638 contract with the federal government. Much of the power that GRICUA re-sales is purchased from SRP. GRICUA also has Western hydropower allocations in its energy portfolio. By having the hydropower contract power wheeled through Western, GRICUA has avoided some wheeling charges from SRP.
   d. New customers pay GRICUA for the interconnection facilities. GRICUA has a line extension credit for home owners for 100 or so feet of the power line built without cost to the customer. For operation, GRICUA first began with an administrative assistant and a Board who then began to contract out services such as line repair. Linemen where hired to build new infrastructure. One of these linemen is a tribal member. GRICUA was able to obtain tribal member employees via the Work Initiative Act (WIA) and through TERO.

e. GRICUA is looking at leasing a large portion of land to a third party-developer who is proposing to build a utility-scale solar array. GRIC will receive a lease payment and some of the power at avoided cost and re-sale it to customers on the reservation. This arrangement is more advantageous to the tribe than having GRICUA own and operate the solar array. Roof-top solar is problematic for GRICUA since they do not have a net–metering program for their customers so the return on investment for individuals is negative.

f. GRIC does not have the same constitutional issues regarding leasing (over $50,000) or incurring debt (greater than $250,000) that Hualapai does which requires a vote of tribal members in order to approve these ventures. Hualapai was able to amend its constitution to allow tribal council to vote to incur debt over $250,000 vs. holding a referendum vote. GRICUA does not require approval of GRIC tribal council to take on most debt. GRICUA can borrow up to $20 million without council approval. This ceiling was granted after GRICUA proved it could manage the electric service. GRICUA operates autonomously from tribal council; however, tribal council may step in and override a GRICUA decision.

g. It is best to engage tribal members on the benefits of having a tribal utility at an early age (5^{th} grade). GRICUA supports a STEAM (science, technology, engineering, architecture and mathematics) program and also has summer interns' work for the utility in meaningful positions.

h. GRIC has a master land use plan which has been developed through much public involvement. GRIC also adopted its own leasing regulations under the HEARTH Act (2012) and has an environmental review process which complies with the principals of the National Environmental Policy Act (NEPA).

i. For system reliability, GRICUA is seen as an improvement over service from SCIP. Lack of SCIP reliability was an impediment to commercial and residential users.

j. The main objective of the HTUA is to bring hard-line power to Grand Canyon West. This will allow future development to occur and also supply sufficient power to the anticipated electric loads to pump and purify the Colorado River water entitlement which should be fully implemented by 2028. The HTUA may also look at taking over billing from Mohave Electric Cooperative (MEC) as a way to develop the HTUA into an operational utility. Currently, the Ak-Chin Electric Service (ACES) provides this function. In addition, the construction of the power line to Grand Canyon West will help the HTUA gain valuable experience in building power lines. The HTUA should consider taking advantage of training offered by the Arizona Public Power Association.

k. The 2007 HTUA feasibility study, updated in 2009, noted that the power delivered to the Nelson substation could be split (most likely between Peach Springs and the MEC 70-mile line). The Hualapai are currently updating this study in the hopes of taking over control of the Peach Springs distribution system from MEC.

l. The key recommendation from GRICUA is to run the utility as a business, not a charity.

4) Adjourn

Hualapai Tribal Utility Authority (HTUA) Meeting Minutes

February 14, 2018, 9:15 AM to 10:00 AM, Hualapai Health Department, Peach Springs.

Board members:

Charles Vaughn, Chairman – present

Joe Montana, Vice-Chairman – present

Jamie Navenma, Secretary – present at 9:25 AM

Bill Cyr, Treasurer – present via telephone

Rory Majenty – absent

Support personnel and guests:

Kevin Davidson, Planning Director

Lauren Ferrigni, Fennemore Craig (via telephone)

Bob Becherer, IMEG (via telephone)

1) Call to Order

2) Roll Call

3) Review and Approval of Minutes from January 10, 2018, meeting

Mr. Vaughn made a motion to approve the meeting minutes of January 10, 2018, with minor corrections. Mr. Montana seconded the motion. Motion carried 3-0-2.

4) Project Updates

a. Proposed Power Line to Grand Canyon West

i. Outcome of Kick-off meeting with consultants Mr. Davidson reported that the kick-off meeting had nearly 30 people in attendance with half attending via the conference call. Mr. Montana and Mr. Majenty attended in person. The one and one half hour meeting went well and allowed the team players to introduce themselves to each other and designate their points of contact.

Mr. Vaughn asked for some elaboration and Mr. Davidson replied that the BIA will request the HTUA to prepare a right-of-way plat for the power line on the reservation and have it memorialized with a tribal council resolution. For Western Area Power Administration, the application to cross their right-of-way is a single page, much of which has been reviewed by Western last year. Mr. Whitefield at the BLM will have the most work to do representing the lead agency on environmental review, but he did not see any apparent issues with the routes.

ii. **Load Forecast and possible amendment to T&D + Q-Spec contract** Mr. Davidson said one item brought up at the kick-off meeting with the USDA was identifying which consultant will prepare the load forecast (7 CFR 1710.205 and 207) for Grand Canyon West. T&D Services + Q-Spec can assist with this effort but it is not an explicit part of their contract. Mr. Becherer has done a significant amount of load forecasting for the project so far and is the logical person to fully develop it with support from T&D Services. This is the first step in the loan application and should be done in the next six to eight weeks. To help with the load forecast, Mr. Vaughn requested Mr. Davidson contact Grand Canyon Resort Corporation to obtain their annual visitation counts. This may be done with a formal letter if need be.

Mr. Becherer said he will use the 2015 Master Plan for Grand Canyon West to estimate load. Mr. Vaughn reminded those in attendance that the master plan has not been formally adopted by the tribe. Using the tribe's water rights bill would be appropriate. Mr. Davidson said he will send Mr. Becherer S.1770 for use in the load projections. Mr. Becherer will include water pumping in the load calculation in case the take out point for the water rights settlement is at Grand Canyon West. Mr. Cyr requested that the spreadsheet analysis allow for different load scenarios so the HTUA can make its own projections. Mr. Becherer added that having the current demand and usage from the diesel generators is necessary for the projections since it will establish a benchmark to ground truth the projections we are currently using to estimate today's load and usage. Mr. Cyr said estimating the current small load at Grand Canyon West may not be as critical since no more than two generators are operating at once (below 1.5 MW). Mr. Vaughn said the load forecast should include public facilities such as a school, clinic and other support uses that the Hualapai people will demand as part of a new community at Grand Canyon West.

iii. **Access to private lands along power line route** Mr. Davidson said he has yet to hear from Mr. Rhodes or Mr. Mardian on giving their permission to the HTUA to access their private lands for the power line survey and archeological survey. To help this along, Mr. Davidson presented Mr. Vaughn with an update of the original letters dated December 13, 2017, for his signature. The new letters will be delivered to each land owner via courier to confirm they are handed to a person.

iv. **Status of Interconnection Agreement** Mr. Davidson said Tucson Electric Power (TEP) has acknowledged receiving the interconnection request in an e-mail dated February 1, 2018, and estimated it would take until the end of the month to have a formal proposal from TEP. Ms. Ferrigni said she would follow-up with TEP if the HTUA does receive a formal proposal in the next few weeks.

b. Cost of Service Study

i. **Progress to Date** Mr. Davidson referenced the e-mail from Mr. Bowman of Intergroup and said the revised draft should be available for himself and Mr. Cyr to review within the next week. The study will be presented to the HTUA at the March Board meeting.

c. Community-Scale Solar Array Feasibility Study

i. **Presentation date to tribal council** Mr. Davidson said Mr. Mason is preparing to make a presentation to tribal council on March 10th. The goal is to have council understand the cost of the project including any benefits. Mr. Vaughn said as long as MEC has control over purchasing and scheduling the power, there is no benefit to Hualapai. Also, with the new solar module tariff imposed in January, the overall cost of the solar power plant has increased by over $100,000 making its financing more tenuous even if the tribe were to obtain a one million dollar grant from the Department of Energy (DOE) to help offset construction costs.

d. Community Wi-Fi

i. Update on BIA's investigation into AT&T's coaxial cable and fiber optic right-of-way lease terms Given the incomplete information the tribe has on file for the lease, Ms. Varela of BIA Realty has also contacted Mr. Luis Ortega of AT&T's Right-of-Way Division and requested the lease documents. With no additional information forthcoming, Ms. Varela will recommend the tribe set-up a formal meeting with AT&T to discuss the contents of the existing lease and how to proceed. Mr. Vaughn advised Mr. Davidson to apprise council of the situation.

e. Mohave Electric Cooperative

i. Request to MEC to provide records of rights-of-way not on file with BIA Mr. Davidson said that MEC is currently assembling the data requested by the HTUA at last month's meeting. Mr. Vaughn noted that the leases should only be those that are relevant to Hualapai.

5) Other Matters (Planning)

a. Review of meeting with Gila River Indian Community Utility Authority Mr. Davidson reviewed the two pages of notes taken from the January 24, 2018, meeting with GRICUA. Mr. Vaughn suggested that HTUA take over the billing operation from MEC by placing a meter at the reservation boundary. This approach proved effective for GRUCUA when they began their operations. Mr. Davidson noted that the key piece of advice from the GRICUA Board is to treat the utility as business not charity (see minutes of Special HTUA Board meeting of January 24, 2018, posted at https://www.hualapaiutility.org/ for a full discussion).

b. Highlights from ATEA conference Mr. Davidson referred the Board to three of the presentations made at the ATEA conference which the HTUA may find of interest. The Ak-Chin Energy Services (ACES) presentation discussed several issues including how they are addressing residential customers with extreme energy uses through educational efforts. The Sandia National Labs presentation by Sandra Begay reviewed efforts by NREL to bring energy education and renewable technology to Indian Country. The ITCA presentation discussed the DOE's weatherization program which may be implemented by tribal housing authorities. Mr. Navenma said the Hualapai Housing Department has used these funds in the past, however, funding has not proved adequate to fully weatherize a home. All presentations may be found at: http://www.tribal-energy.org/).

c. **Announcements** The Arizona Power Authority is hosting a luncheon on Friday with a presentation on the history of Western Area Power Administration. No other announcements.

6) Set time and location for next meeting The next meeting is set for Wednesday, March 14, 2018, at 9:00 AM at the Hualapai Health Department, Peach Springs.

7) Adjourned at 10:00 AM

Hualapai Tribal Utility Authority (HTUA) Meeting Minutes

March 14, 2018, 9:20 AM to 11:00 AM, Hualapai Health Department, Peach Springs.

Board members:

Charles Vaughn, Chairman – present

Joe Montana, Vice-Chairman – present

Jamie Navenma, Secretary – present

Bill Cyr, Treasurer – present

Rory Majenty – present via telephone

Support personnel and guests:

Kevin Davidson, Planning Director

Lauren Ferrigni, Fennemore Craig (via telephone)

Bob Becherer, IMEG (via telephone)

Tom Mason, Rock Gap Engineering (via telephone)

Patrick Bowman, Intergroup (via telephone)

1) Call to Order[1]

2) Roll Call

3) Review and Approval of Minutes from February 14, 2018, meeting

Mr. Cyr made a motion to approve the meeting minutes of February 14, 2018. Mr. Montana seconded the motion. Motion carried 4-0-1.

[1] HTUA entered the conference call link at 9:10 AM and learned from Mr. Becherer's discussion with Mr. Bowman that new loads along Buck and Doe Road where the proposed 69 KV line will be built should be large enough to warrant the cost of installing step-down transformers. This would also apply to loads along the 69 KV line if it was to run into Peach Springs, a distance of some 60 miles from the Dolan Springs substation. Mr. Vaughn asked what size conductor is needed to run power to Peach Springs to avoid voltage drop. Mr. Becherer advised using a 4-aught conductor. However, the conductor would have to be upsized from the Dolan Springs substation to the "T" on Buck and Doe Road where the line divides to serve loads at Grand Canyon West and Peach Springs. Mr. Cyr added that voltage drop can be controlled with regulators, capacitors and tap chargers.

4) Project Updates

a. Proposed Power Line to Grand Canyon West

i. Status of Survey and access to private lands along power line route Mr. Davidson reported that as of March 4, 2018, Taney Engineering was setting panels along the route and was beginning to stake the route from the Dolan Springs substation to Tenny Ranch Road. Mr. Cyr asked about the type of panels and Mr. Davidson replied these will be used by the aerial photographer to ortho-rectify the photos to the actual survey coordinates. After the flight is complete, the panels will be removed.

For access to private land, Mr. Mardian has granted permission to the HTUA to access his property in Section 13 for the power line survey and archeological survey. However, Mr. Davidson noted that Mr. Mardian's permission does not give the HTUA rights to construct a power line across his property. Mr. Vaughn asked what compensation Mr. Mardian would likely seek for having a power line cross his land. Mr. Davidson said he may be looking for access to power. Mr. Vaughn asked if this is the only route to Grand Canyon West. Mr. Davidson said a second option would be to cross land owned by Mr. Rhodes whose property is located on the opposite side of the "butterfly" in Section 19 with BLM holdings on the either side (Sections 18 and 24). Mr. Rhodes has not responded to the HTUA's inquiry to cross his land. Mr. Davidson opined that if the HTUA's radial distribution line serves a non-tribal load off of the reservation, it may be considered a transmission line for at least the first mile or so of the power line's run and that portion may require FERC approval.

ii. Status of National Environmental Policy Act (NEPA) review Mr. Davidson said Andy Whitefield, Bureau of Land Management, has set-up a kick-off meeting for the NEPA review with Tierra Right-of-Way for 10:30 AM on Tuesday, March 20, 2018, at the Kingman Field Office. The priority route is along Tenny Ranch Road, with the Clay Springs Road route only being investigated if the Tenny Ranch Road route proves untenable during the NEPA review.

iii. Status of Interconnection Agreement Mr. Davidson reviewed his notes from the March 13, 2018, meeting with Tucson Electric Power (TEP)/UniSource as follows: 1) model the load as well as back-up generators, 2) look at outages and impacts of those outages on the system and also range of service, and 3) determine best path to send Hoover power to Grand Canyon West. To do this TEP will need to file an OASIS report to transmit this power. The System Impact Study will take about 60 days and focus on an initial 3 MW load. The HTUA may ask for additional impact studies as loads grow beyond 3 MWs (up to 9 MWs in the next ten years). The new Grand Canyon West substation will be used to monitor load and be configured in such a way as to allow the Grand Canyon West generator set to run independently of TEP/UniSource power supply. The HTUA prefers only a 30 second to 60 second gap between a UniSource outage and generator start up. Ideally, generators will run in parallel with UniSource if power quality needs improving. To proceed, the HTUA will provide TEP with the generator specification. The cost of the impact study is $30,000. TEP will send the agreement for signature. The HTUA will contact Ms. June Deering at UniSource's Kingman Office to determine if there are any remaining funds from original $100,000 deposit made by the tribe in 2010 for the initial analysis to credit toward the new System Impact Study. Mr. Vaughn noted this new expense may require a budget adjustment through the Finance Department.

Mr. Vaughn asked how the HTUA could contain the power produced by the existing generators at Grand Canyon West. Mr. Becherer replied the new Grand Canyon West substation could be designed to keep the power from being put onto the new 69 KV and sent back to Dolan Springs. Mr. Cyr asked about UniSource wanting to synchronize their grid power with the existing generator sets to maintain power quality. Mr. Becherer was also surprised to hear this from UniSource but said it would be good to have such a plan in place. Mr. Cyr asked if the 30- to 60-second power outage to generator start-up was a requirement of the HTUA. Mr. Becherer said he is looking to optimize the response time of the generators to keep Grand Canyon West energized. The gap should allow the generators to start-up, synchronize and lock-out the new substation.

iv. Load Forecast and possible amendment to T&D + Q-Spec contract Mr. Davidson said one item brought up at the kick-off meeting in February was identifying which consultant will prepare the load forecast (7 CFR 1710.205 and 207) for Grand Canyon West. Mr. Becherer has done a significant amount of load forecasting for the project so far and is the logical person to fully develop. To that end, IMEG has submitted a contract amendment in the amount of $9,340 to allow Mr. Becherer to perform this task. Mr. Cyr requested, in light of a latter agenda item regarding the hiring of a part-time General Manager for the HTUA, that this item be tabled. Mr Davidson said the study can be delayed somewhat. Mr. Vaughn seconded the motion. Motion approved 4-0-1. Mr. Davidson noted the HTUA is now receiving telemetry from the generators, key to the load study.

b. Cost of Service Study

i. Progress to Date Mr. Davidson introduced Intergroup's new findings by noting that Mohave Electric Cooperative (MEC) does not currently have authorization to wheel third-party power to customers from any substation including the Round Valley (near mile post 92 on Interstate-40) or the Hualapai (Blake Ranch) substations; however, MEC may be able to develop an O&M charge to do so which would require Arizona Corporation Commission approval. Another option to deliver electricity to the reservation is to construct a new power line from the Round Valley substation to the Nelson substation where the tribe can easily access it. Mr. Bowman said the original findings noted a $250,000 annual operating deficit to the HTUA should it take over MEC's electrical service in Peach Springs. This would require an electrical rate increase of 37 percent for the HTUA to break even. To help reduce the amount of rate increases, new loads at Grand Canyon West and the pumping of the tribe's future anticipated Colorado River water allocation (water rights settlement) are needed. The cost of the HTUA purchasing bulk power is not appreciably different than those costs incurred by MEC (5 cents vs. 5.8 cents per KWHr). Western Area Power Administration (WAPA) may supply the tribe's hydropower allocation, and additional power as needed, to the Round Valley substation: however, the challenge is to deliver that power to the Nelson substation as Mr. Davidson noted above. Mr. Vaughn asked about the possibility of receiving power from APS. Mr. Bowman said such a supply could come with a utility-scale solar array connected to the Eldorado-Moenkopi 500 KV line on the Hualapai Reservation. This line may be considered for conversion to Direct Current making it even a less likely option. Aside from a new MEC O&M charge or new 69 KV line from Round Valley to Nelson, the new 69 KV power line to Grand Canyon West could also supply power to Peach

Springs via Buck and Doe Road.[2] Mr. Bowman added that MEC is open to working with the HTUA on setting up an O&M charge to wheel power to the reservation.

Mr. Bowman said the tribe's hydropower allocations from WAPA could be delivered to Round Valley at about five cents per KWHr. Wheeling charges over WAPA's system would be about $30,000 per year. The tribe's annual Hoover power allocations (D1 and D2) amount to about 1,000 MWHrs of energy per year. However, the tribe's existing revenue from these allocations through the bill credit with MEC and benefit arrangements with Pechanga and Navajo would be negated if the tribe used this power directly. The HTUA would also have to pay MEC an O&M charge to bring this power from its substations. Even with a retail rate of 8.5 cents per KWHr, the small loads in Peach Springs make it difficult for existing customers absorb a rate increase.

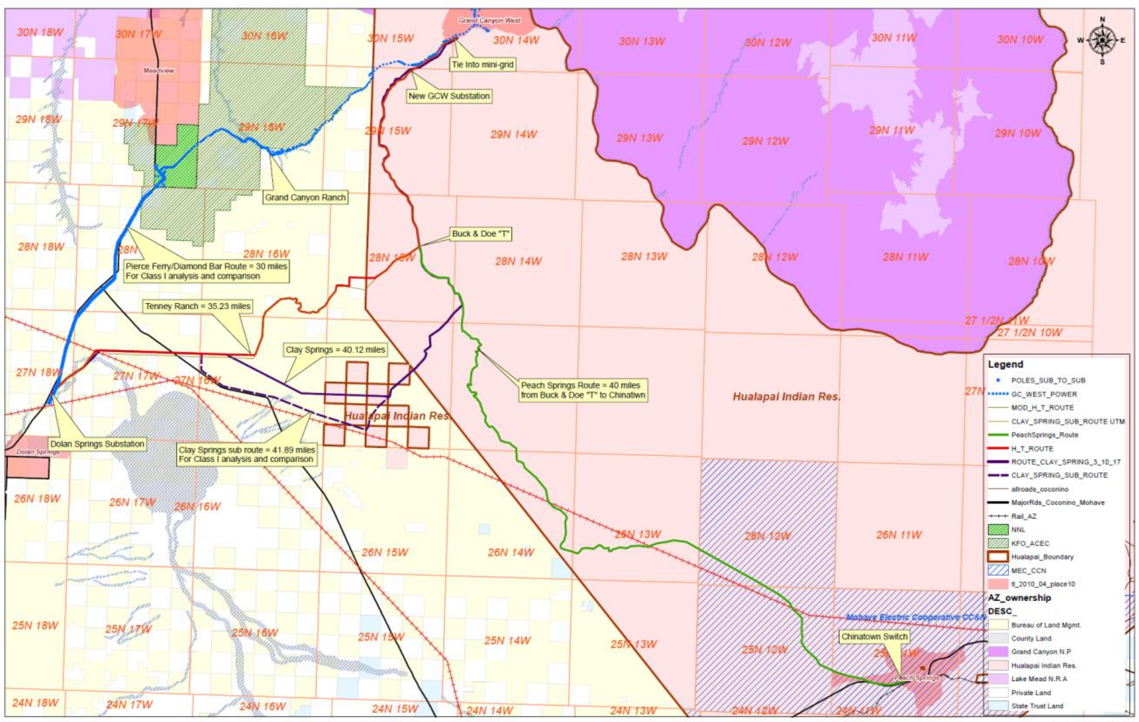
In regard to purchasing the existing electrical system in Peach Springs, some of the equipment is encumbered by a USDA loan so the price may exceed net book value to meet USDA's minimum asset value criteria. Also, the meters are proprietary and must be returned to MEC. The HTUA will need to budget for replacement meters. Mohave Electric Cooperative also must maintain a 24.9 KV line between its Hualapai and Nelson substations for redundancy and to serve downstream customers. This would asset reconfiguration with the HTUA or a new and separate power line between the two substations. Building a new power line for MEC would be an extra cost to the HTUA. Mohave Electric Cooperative prefers one delivery point to supply power to the tribe, namely the Nelson substation. The HTUA would most likely want to serve all loads on the reservation (Burlington Northern Santa Fe and Federal Aviation Administration) aside from its own. However, taking over the 70-mile line to the Havasupai may be an exception given the responsibility of maintaining the line for mostly downstream customers. Mr. Davidson asked if having one point of power delivery from MEC would perpetuate the "radial line" issue. Mr. Bowman said not in the this case because MEC's loop between substations could be tapped by the HTUA to supply power in the case of the Round Valley–Nelson supply going off line. Mr. Cyr noted that WAPA has a mandate to deliver hydropower to tribes.

Looking at delivering power from UniSource via the proposed Grand Canyon West 69 KV line may be an option. Mr. Becherer said the distance is at least 34 miles from the Buck and Doe "T"

[2] See discussion of this option under Footnote 1 on page 1.

to Peach Springs (see map).[3] Mr. Vaughn noted that building a 69 KV power line will allow for a water diversion option at Grand Canyon West. Bringing the water allocation to Grand Canyon West will cost less than diverting it at Diamond Creek and then building a 70-mile long pipeline to Grand Canyon West. Mr. Davidson asked if a 60-plus-mile long 69 KV power line is feasible. Mr. Cyr said it could but a 115 KV or 138 KV line would be more efficient. Mr. Navenma said the tribe should look at the long-term growth of the tribe and provide enough power for both future water pumping as well as increased population in both Peach Springs and Grand Canyon West.

69 KV Powerline Routes from Dolan Springs Substation to Grand Canyon West



c. Community-Scale Solar Array Feasibility Study

i. Presentation to tribal council Mr. Davidson reviewed the presentation made by Mr. Mason to tribal council on Saturday, March 10, 2018. Tribal council is seriously considering placing the array at the Nelson site where is can serve both Peach Springs and the lime plant. The resolution was approved for a 1 MW solar in Peach Springs[4]. Mr. Vaughn noted that MEC would have

[3] The distance from the Buck and Doe "T" to the Chinatown switch is approximately 40 miles. The connecting to the 24.9 KV line on Buck and Doe Road would be approximately 36 miles.

[4] At the meeting Mr. Davidson noted the resolution was tabled but was informed by staff that it was approved.

complete control of the power if the array was built at the West Peach Springs signal site and it would require a subsidy from the tribe to operate with no benefit to Hualapai. Mr. Mason read an extract form the Department of Energy (DOE) grant which the tribe is planning to apply for to help build the solar array as follows: “All proposed projects must be on tribal land and controlled by the tribe.” Mr. Mason said the array must be grid-connected to grant eligible. However, some of the power from the Nelson solar array could be sold to Lhoist mine “behind the meter” akin to a roof-top solar array. The tribe would build a single line to Lhoist to deliver the power “behind the meter.” The balance of the power would be sold to MEC and delivered to the Nelson substation where it would be sent back into Peach Springs. By having two customers, with one paying a near retail rate for power, the array should make economic sense. Mr. Cyr asked if the HTUA had recommended a site to tribal council. Mr. Davidson replied that it had not and that the Saturday presentation to council was to test their interest in the solar array. Mr, Vaughn noted Lhoist’s high start-up demand (7 MWs). Mr. Vaughn asked if the DOE grant required management of the array. Mr. Mason said he had added staffing costs to the solar array budget.

Moving back to the discussion of managing the tribal utility authority, Mr. Montana asked if the HTUA would want to take over the task of reading meters on the reservation. Mr. Navenma advised the HTUA sub-contract meter reading and billing to a qualified company.

d. Mohave Electric Cooperative

i. Request to MEC to provide records of rights-of-way not on file with BIA Mr. Davidson said that he just received MEC’s data in the mail and will be reviewing it with the BIA next.

5) Other Matters (Planning)

a. Review and possible action on Statement of Qualifications HTUA General Manager Mr. Davidson said Mr. Cyr of BC Consulting applied for the part-time manager position by the deadline. One other person asked about the position after the closing date on February 26, 2018. Mr. Davidson has scored Mr. Cyr’s SOQ and found his firm to be acceptable. Mr. Cyr noted his experience with the Aha Macav Power, some 35 years in the power industry as an engineer and said that the HTUA is developing a good plan which should be profitable. Mr. Cyr asked if he could retain his board membership while serving as the part-time GM. Mr. Davidson will review the HTUA Ordinance with the attorney to confirm the answer. Mr. Vaughn, Navenma, Montana and Majenty all found Mr. Cyr to be well qualified and a good fit for the HTUA's requirements of a General Manager. Mr. Vaughn made a motion to accept Mr. Cyr of BC Consulting as the part-time general manager for the HTUA, Mr. Navenma seconded the motion. Motion passed 4-0-1 with Mr. Cyr abstaining.

b. **Announcements** The DOE has published the NOFA for community-scale solar array. No other announcements.

6) **Set time and location for next meeting** The next meeting is set for Wednesday, April 11, 2018, at 9:00 AM at the Hualapai Health Department, Peach Springs.

7) **Adjourned at 11:00 AM**

Hualapai Tribal Utility Authority (HTUA) Meeting Minutes

April 11, 2018, 9:20 AM to 10:55 AM, Hualapai Health Department, Peach Springs.

Board members:

Charles Vaughn, Chairman – absent

Joe Montana, Vice-Chairman – present

Jamie Navenma, Secretary – present

Treasurer – Vacant

Rory Majenty – present via telephone

Support personnel and guests:

Bill Cyr, General Manager

Kevin Davidson, Planning Director

Peter Bungart, Cultural Resources Director

Lauren Ferrigni, Fennemore Craig

Patrick Black, Fennemore Craig

Mike Jackson, IMEG

Bob Becherer, IMEG (via telephone)

Todd Stoval, Taney Engineering (via telephone)

1) Call to Order

2) Roll Call

3) Welcome new General Manager

The HTUA Board and attendees welcomed Mr. Cyr as the new general manager. Mr. Davidson had Mr. Cyr sign the tribe's Professional Services contract to commemorate the transition. Mr. Cyr has resigned from the HTUA Board to assume the role of general manager for the HTUA.

4) Review and Approval of Minutes from March 14, 2018, meeting

Mr. Navenma made a motion to approve the meeting minutes of March 14, 2018. Mr. Montana seconded the motion. Motion carried 3-0-1.

5) Project Updates

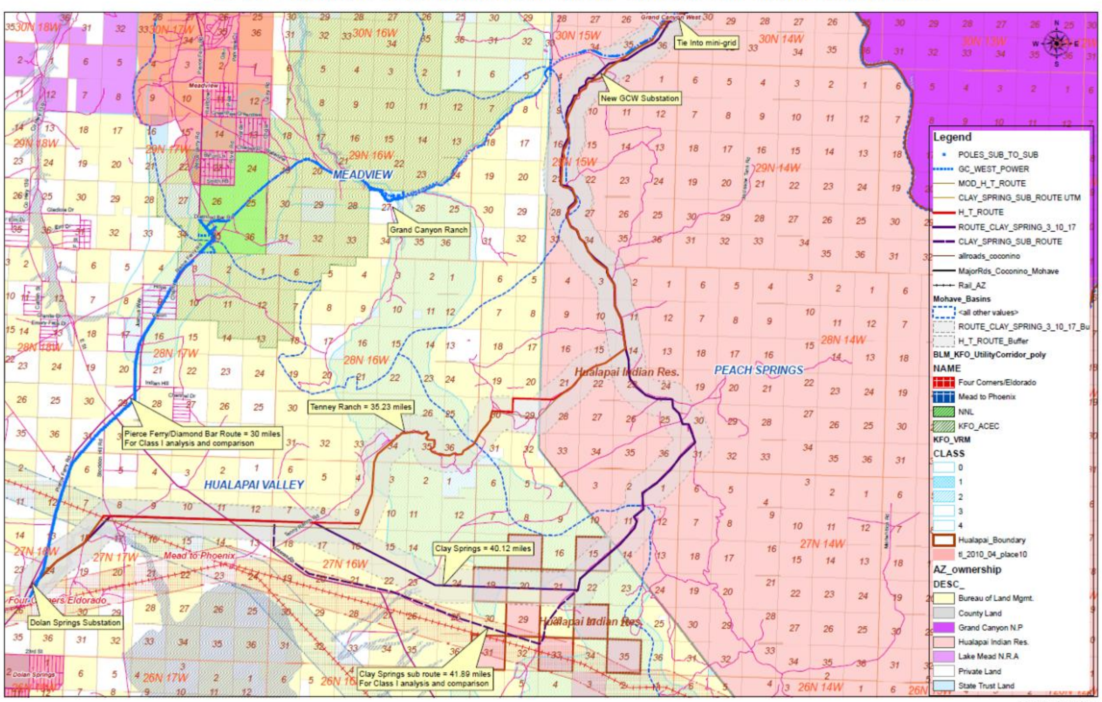
a. Proposed Power Line to Grand Canyon West

i. Status of power line survey and scheduling a field trip Mr. Stoval reported that all survey stakes marking the centerline of the 35-mile power line have been placed except for the last mile along that portion of Tenny Ranch Road where there is steep terrain and roadway switch backs. This area was left un-staked until the project engineer can walk the route to determine the preferred course of the power line. Mr. Stoval said the aerial survey, showing topography, should be complete by June 4, 2018. Mr. Cyr asked if he could obtain a map showing the alternate routes. Mr. Becherer said he would provide Mr. Cyr with a map to review. To help provide an understanding of the topography in question, Mr Stoval will transmit an electronic file (kmz) that can be mapped in Google Earth. Mr. Bungart noted the potential of artifacts being discovered along both the Tenny Ranch Road routes and Clay Springs Road route given that these areas were frequented by both the Grass Springs and Clay Springs bands of Hualapai. Mr. Cyr asked about the need to walk the staked route. Mr. Becherer advised those areas along Tenny Ranch Road that have yet to be staked be covered on foot and marked so Mr. Stoval can finish out this portion of the contract. However, those portions that cross open terrain may not need as much scrutiny and can be reconnoitered by air. Mr. Stoval added that most of the staking is along existing roads and trails that may be accessed by motor vehicle. The stakes are six-foot high PVC placed over rebar which are driven into the ground some 24 inches. Stakes are spaced 500 feet apart with smaller wooden stakes placed between if terrain obstructs the 500-foot line of sight between the PVC markers.

ii. Status of NEPA review, cooperating agencies (USDA & BIA) and revised Indirect Cost Agreement with BLM Mr. Cyr asked Mr. Davidson to update the board on the results of the kick-off meeting for the NEPA review with the tribe, BLM, and Tierra Right-of-Way held on Tuesday, March 20, 2018, at the Kingman Field Office. Mr. Davidson reviewed the meeting minutes and stated the most significant impact to the region may be on the transportation network given that the power line will allow more growth to occur at Grand Canyon West, namely a hotel, welcome center and eventually a community. This will be especially true if the tribe is able to settle its water rights to the Colorado River which will allow more growth on the reservation in general. However, the foot print of the power line should be nearly the same whether it serves a 3 MW or a 10 MW load at Grand Canyon West.

Alternative routes discussed this far have been 1) Grapevine Canyon following Pierce Ferry, Diamond Bar, and Buck and Doe Roads: this alternative has been discussed extensively but has been eliminated from detailed analysis due to its crossing through the Grapevine Mesa-Joshua Tree Forest Area of Critical Environmental Concern (ACEC) and the Joshua Tree National Natural Landmark (NNL), 2) Tenny Ranch Road, a.k.a. Hells Canyon Road, is the Tribe's preferred alternative, even though steep terrain may make construction difficult in areas. This route crosses northern Hualapai Valley to Antares Road then easterly along an existing road to intersect with the Tenny Ranch Road, generally following it to Buck and Doe Road then north to Grand Canyon West, and 3) Clay Springs Road which follows the Tenny Ranch Road Alternative for the most part, except instead of turning east near Tenny Ranch it would continue somewhat parallel to Antares Road to Clay Springs Road, then northeast to Buck and Doe Road and north to Grand Canyon West (see map). This site has several cultural concerns identified by the Hualapai Cultural Resources Department. All routes originate at the existing UniSource 69 KV substation on Pierce Ferry Road just north of Dolan Springs.

69 KV Powerline Routes from Dolan Springs Substation to Grand Canyon West



Project components and design consist of: 1) a 50-foot wide right-of-way (ROW) for the power line, 25 foot wide ROW for access roads where it would be outside the power line ROW, temporary ROW areas for construction of 50 feet on either side of power line ROW and 25 feet wide on either side of access roads, 2) right-of-way for two lay-down areas with one adjacent to Antares Road near its intersection with Tenny Ranch Road, and the other on the Hualapai Reservation adjacent to Buck and Doe Road, 3) Structures would be single wooden poles approximately 55 feet in height with steel self-weathering poles at turning points and for longer spans, 4) poles and hardware configuration would be "raptor proof" with non-specular conductors. Wood poles are suggested in lieu of steel poles to save cost. Steel poles are anticipated along Tenny Ranch Road steel poles where they may reduce the number of poles that would otherwise be used in steep terrain.

For construction access and maintenance, existing roads would be used as much as possible and, in areas of little slope, access would likely be created by vehicle/equipment travel; however, wash crossings should be contoured. Access to pole locations will be described in the environmental assessment, especially in regards to methods of installing poles in steep terrain. Areas of disturbance, both temporary and residual, will be estimated and described in the EA. Reclamation may be required anytime there would be access to the poles, unless there is no road included in the ROW grant. Travel lanes will be kept to 12 feet in width, however, wider roads may be considered if there are access issues. Access routes will be determined and surveyed for cultural artifacts. Access roads over flat country are anticipated to stay within the 50-foot right-of-way.

For the preparation of the EA, it is being drafted by Tierra Right-of-Way. Scoping meetings should be held in Peach Springs and Dolan Springs. The EA should be complete in 10 months. The USDA will also be reviewing the EA since it is linked to an existing Rural Utility Services (RUS) grant and future RUS loan. The BLM's Kingman Field Office staff will identify resource concerns. For example, Mexican Vole habitat may need to be addressed. Both routes cross through Class 2 visual resource management areas (VRM). Key observation points must be identified. The EA should also consider the view-shed or landscape perspective during the visual analysis. The EA should develop thresholds for this process and examine resource concerns such as visual, wildlife, cultural assets. Also, new Wilderness characteristic inventories will be taken into account for this analysis. Numerous cultural sites have not been registered with Arizona State Museum within the Clay Springs area.

In regard to processing the EA, the tribe and Tierra Right-of-Way request the BLM to have comments prepared within 2 weeks of submittal for review barring unusual circumstances. New federal guidelines for EAs limit page length to between 25-50 pages. Appendices and reference documents are not included in the page limit. The priority route is along Tenny Ranch Road, with the Clay Springs Road route only being investigated if the Tenny Ranch Road route proves untenable during the NEPA review.

To conclude, Mr. Polacek of the USDA has requested a letter from the BLM stating that the BLM act as the lead agency in performing the EA and that USDA will be a cooperating agency. The BLM is also working with BIA to designate that agency as a cooperating agency.

iii. Review of Interconnection Agreement and possible action on payment to Tucson Electric Power to complete System Impact Study Mr. Davidson reported that UniSource has $14,028.77 in funds remaining from the original system impact study performed in 2012 and is looking to see how they can transfer the money to TEP to help for the new system impact study which requires a $30,000 deposit to begin. Mr. Cyr asked about the parameters of the study. Mr. Becherer and Mr. Davidson reviewed their notes from the March 13, 2018, meeting with Tucson Electric Power (TEP)/UniSource as follows: 1) model the load (up to 3 MWs) as well as back-up generators, 2) look at outages and impacts of those outages on the system and also range of service, and 3) determine best path to send Hoover power to Grand Canyon West. To proceed, the HTUA will provide TEP with the diesel generator specifications. Mr. Cyr asked if it would be better to model the total capacity of the system to determine how much power UniSource can deliver to the substation. Mr. Cyr advised the board that it would be best to discuss the scope of the study with TEP prior to paying them the deposit to begin the study. Mr. Davidson will provide the results of the 2012 study for Mr. Cyr to review.

b. Cost of Service Study

i. Progress to Date Mr. Davidson noted the cost of service study is nearing completion. The major findings of the study indicate that serving Peach Springs alone is too small of a load to be economically viable. Adding a large water pumping load would improve the economics assuming the load was charged a retail rate and connected to the existing MEC electrical distribution system. Serving load at Grand Canyon West may help spread the cost to a large commercial customer; however, the cost of paying for a new power line to serve the Grand Canyon West load may make the energy more expensive than the current diesel generation.

ii. Review and possible action on payment to MEC to obtain net book value of facilities Mr. Davidson said MEC would like an additional $3,031.87 to provide the tribe with the net book value of the electrical facilities on the reservation. The data would prove useful if the tribe seeks to buyout the electrical system in the next few years. Mr. Cyr said he would first like to meet with Mr. Carlson, MEC's CEO to understand how open MEC is to divesting itself of its facilities on the Hualapai Reservation. Also, if the HTUA were to pursue the purchase, MEC would provide the net book value to help with the negotiation process. The board decided to defer to the question of payment and allow Mr. Cyr to meet with Mr. Carlson.

c. Community-Scale Solar Array Feasibility Study

i. Revised Power Purchase Agreement sent to MEC for comment Mr. Davidson reviewed the draft PPA and said the price per MWhr was set at MEC's avoided cost rate of $25.00/MWhr over the 25 year agreement with adjustments for inflation made every five years. The agreement allows the HTUA to sell power to other users. This would include the near-by chemical lime plant. Mr. Campos is reviewing the document and should have comments shortly. Mr. Bungart asked if the future operations of the chemical lime have been taken in to account. Is there a danger of the mine shutting down operations during the life span of the solar array?

ii. Status of grant application to Department of Energy Mr. Davidson said the grant is due on April 19th. Mr. Cyr asked when DOE is expected to make the award announcements. Mr. Davidson said he is expecting a notification in late June of 2018. Mr. Montana asked if any excess power could be wheeled outside of the MEC grid and could the HTUA add additional solar capacity on to the grid. Mr. Cyr said he will ask Mr. Carlson about MEC's ability to wheel power to points off the reservation.

d. Mohave Electric Cooperative

i. Review records of rights-of-way on file Mr. Davidson referred to a table of power line easements he was able to obtain from MEC. Some of these easements have expired or are about to expire. Mr. Cyr asked if these could be mapped. Mr. Davidson said they could be using a GIS file he received from MEC last fall. When it comes to renegotiating the easements, Mr. Black advised that Mr. Cyr first talk to the Arizona Corporation Commission because they are sympathetic to issues of tribal sovereignty.

6) Other Matters (Planning)

a. Obligation of new Boulder Canyon Project power allottees to report to WAPA Mr. Davidson notified the HTUA that they must provide a yearly financial report as specified under Section 34 of the Arizona Power Authority Power Sales Contract. This applies to the tribe's Schedule D2 allocation which is set up in a bill credit arrangement with MEC. Mr. Cyr said this is a report that he can produce for the HTUA.

b. Update on tribal council actions on Community Connect grant and AT&T wireless proposal Mr. Davidson reviewed the USDA Community Connect grant opportunity that the tribe is both applying for to bring fiber optic to Grand Canyon West and in writing a support letter for WECOM's application to extend their fiber optic line from Valle Vista to Peach Springs. The grant requires a 15 percent tribal cash match. This would reduce the tribe's cost to build the 48-strand fiber optic under build along the new power line from approximately $700,000 to $105,000.

For the AT&T wireless proposal, Mr. Davidson said two cellular towers are proposed, one at Gray Mountain and the other at Grand Canyon West. Both towers will be within 100 or so feet of the existing radio communication towers. This is part of the FirstNet program which is designed to enhance public safety by increasing the speed of telecommunications for first-responders. Tribal council is looking to pursue this venture with AT&T.

c. **Proposed Big Chino Valley Pumped Storage project** Mr. Davidson next referred to a notice from Big Chino Valley Pumped Storage, LLC on a proposed 3,000 MW energy project located just south of Interstate-40 at Picacho Butte. The pre-application document states the project will provide energy storage and grid stabilization for the Southwest with connection points on both the Western and APS transmission lines. Mr. Davidson noted the APS interconnection point is about 15 miles east of the Hualapai Reservation and could provide a tie-in point for a future utility-scale solar array. Mr. Black said there would be significant water loss through evaporation which may prove problematic when facing Arizona's ongoing drought and problems with groundwater depletion statewide. Mr. Black also noted that FERC may not understand this project requires Arizona Corporation Commission (ACC) review and approval. The proposal does fall in line with the current state ballot initiative to have 50% of power produced in Arizona derived from renewable sources by 2030[1] and the ACC initiative to have 80% by 2050. The ACC proposal includes conventional hydropower and nuclear.

d. **Announcements** Mr. Davidson said the tribe is carrying forward six sites for the new administration building as part of the environmental review. The environmental assessment should be complete this year.

7) Set time and location for next meeting The next meeting is set for Wednesday, May 23, 2018, at 9:00 AM at the Hualapai Health Department, Peach Springs.

8) Adjourned at 10:55 AM

[1] The Clean Energy for a Healthy Arizona Amendment requires affected electric utilities to provide at least 50% of their annual retail sales of electricity from renewable energy sources by 2030. The Amendment defines renewable energy sources to include solar, wind, small-scale hydropower, and other sources that are replaced rapidly by a natural, ongoing process (excluding nuclear or fossil fuel). Distributed renewable energy sources, like rooftop solar, must comprise at least 10% of utilities' annual retail sales of electricity by 2030. The Amendment allows electric utilities to earn and trade credits to meet these requirements.

Hualapai Tribal Utility Authority (HTUA) Meeting Minutes

May 23, 2018 Hualapai Health Department Conference Room

1. **Call to Order** *The meeting was called to order by Chairman Vaughn at approximately 9:20 am.*

2. **Roll Call**

   Board Members
   Charles Vaughn, Chairman present
   Joe Montana, Vice Chairman present via phone
   Jamie Navenma, Secretary present via phone
   Treasurer- Vacant
   Rory Majenty- Present---Absent

   Support Personnel and Guest
   Bill Cyr, General Manager present
   Kevin Davidson, Planning Director present
   Patrick Bowman Intergroup present via phone
   Bob Becherer IMEG present via phone

3. **Review and Approve Minutes from April 11, 2018**

   Mr. Vaughn made a motion to approve April 11, 2018 Board meeting minutes with a second by Mr. Navenma —board approved 3-0

4. **Project Update**
   a. **Proposed Power Line to Grand Canyon West**
      i. Status of power line survey- Bobs Report

Mr. Robert Becherer provided an written update included in May 23, 2018 Board package along with a verbal presentation by phone. In Summary

- Initial identification of culturally sensitive sites to avoid
- Identification of private property to avoid
- Recommending moving proposed substation site at Grand Canyon West
- Rest of Bobs report is available in May 23, 2018 Board package

ii. **Status of NEPA/ Environmental**

Work by our consultants and BLM continues to move forward - no real road blocks uncovered yet. Plans for a line walk with BLM out of Kingman in June are being firmed up.

iii. **Review of Transmission Interconnection System Impact Study Agreement and possible action on payment to Tucson Electric Power (TEP)to complete system impact study.**

The Board reviewed a system impact agreement between HTUA and Uni-source/Tucson Electric Power to study the technical merits of a transmission line from Dolan Springs to Grand Canyon West. On a motion by Mr. Naverma and a second by Mr. Vaughn the Board approved 3-0 to proceed with the study and authorized the expenditure of $30,000 to complete the study. (Note: HTUA had a credit of $17,005.85 on account with TEP so the balance due was only $12,994.15. The entire agreement was presented to the Board and is available in the May 23, 2018 Board package.

b. **Cost of Service**

i. **Final Report**

The final report for the cost of service study was provided to the Board in the May 23, 2018 Board package and a verbal presentation to the Board was provided by Patrick Bowman of Intergroup. The study is quite extensive and the key take away is

- Rates would need to increase by at least 30% to all customers on the Hualapai reservation if HTUA would acquire the assets from MEC and take over the day to day operation of supplying electricity to the Hualapai nation

ii. **Simplified HTUA business model (handout)**

Mr. Cyr provided a handout of a simplified business model that was supportive of the cost of service study. The simplified model concluded that if the Hualapai's move forward with becoming an operating utility - that the Hualapai's general fund will need to supplement its income until enough customers or electrical load is acquired or developed to fully support the HTUA revenue requirements. A copy of this hand out can be found at the end of the minute in this section. Mr. Cyr also *recommended that the Board meet with the council to ensure HTUA actions are consistent with Hualapai council goals.*

iii. **Quick look at Financing transmission line**

Mr. Cyr informed the board that regardless of the financing agency that the cost to finance the project will be about $4,300 dollars per month for 30 years at 3% for every million dollars borrowed or in this case if the lines net cost is $15 million then the month payment will exceed $60,000 per month. He also informed the Board that no agency would fund such a project if the borrowing party did not have the revenue to support such a payment and that in the case of HTAU it does not and will not have the revenue to support such a payment. Mr. Cyr again suggested that the Board meet with Hualapai council to discuss how it would like to finance project

- *Tribe pays for line*
- *Tribe pays for line and assigns long term Debt back to HTUA*
- *Grand Canyon west pays for line*
- *Other*

c. **Community- Scale Solar Array (Kevin)**

Mr. Davidson updated the Board on the two items listed below. He should have more information on both items for next month's Board meetings

i. **Revised PPA sent to MEC for comment**

ii. **Status of grant application to DOE**

d. **Mohave Electric Cooperative**

i. **Discussions with MEC**

Mr. Cyr discussed a couple of recent calls he had with MEC management. Mr. Cyr would like to meet with Tribal Council and the HTUA Board to firm up expectations prior to entering into discussions with MEC.

5. **Other matters**

a. **Update on tribal council actions (Kevin)**

Kevin provided the Board with an update regarding his attendance at recent Board meetings

b. **Cell tower AT&T (Kevin)**

Kevin provided a presentation that AT&T made to council regarding proposed upgrades to cell service by ATT that wouldrequire the _utilization of some Trivial assets. Full presentation in May Board package_

c. **Solar Field Trip with US Global**

   Kevin provided a presentation that a meeting he had with Global including a written summary regarding Global provided by Global.. Kevin was not optimistic that anything would result from this meeting

d. **Discussions with WAPA- invite to next Board meeting**

   Mr. Cyr informed the Board that it is agreeable in meeting with Board to discuss how WAPA might be able to help HTUA.   Mr. Cyr would like to have that meeting after the HTUA Board has meet with Tribal Council

e. **BCP Customer Meeting to Review Draft Master Schedule FY18 & FY19**

   Informative email presented to Board regarding an upcoming BCP customer meeting

f. **New Board Member**

   Tabled to next meeting as we may have two vacancies

g. **Announcements**

   none

6. **Set time and location for next meeting**

   Next meeting scheduled for June 27, 2018.

7. **Adjourn**

   Adjourned at 11.00 am

Hualapai Tribal Utility Authority (HTUA) Meeting Minute

July 5, 2018 Hualapai Health Department Conference Room

1. **Call to Order**

   The meeting was called to order by Chairman Vaughn at approximately 9:24am.

2. **Roll Call**

   Board Members
   Charles Vaughn, Chairman- present
   Joe Montana, Vice Chairman- present
   Jamie Navenma, Secretary- present
   Treasurer- Vacant
   Rory Majenty- via telephone

   Support Personnel and Guest
   Bill Cyr, General Manager present
   Kevin Davidson, Planning Director present
   Peter Bungart, Cultural Resources Director
   Patrick Bowman Intergroup - via telephone
   Bob Becherer IMEG - via telephone

3. **Review and Approve Minutes from May 23, 2018**

   Mr. Vaughn made a motion to approve May 23, 2018 Board meeting minutes with a second by Mr. Montana—board approved 3-0

4. **HTUA Meeting with tribal council**

   Mr. Cyr briefed the HTUA board members of his efforts to secure a meeting with the tribal council. Mr. Cyr and Mr. Davidson will work together to schedule a meeting with the tribal council as soon as possible. Key items for discussion with the Hualapai council;

   1. *Revenue and expense forecast*
      - *Acquisition of MEC assets for Peach Springs*
      - *Impact of serving GCW load*
      - *Required additional load to break even*
      - *Impact of Colorado River water pumping load*
      - *Other planned future developments by tribe- housing, casino, hotel...*

2. *Update on GCW transmission line*
    - *General routing discussions*
        - *Right of way work to date*
        - *Environmental work (cultural/ BLM)*
    - *Estimated cost*
    - *How to pay for the line*
        - *Hualapai pay 100% cash*
        - *GCW pay 100% cash*
        - *Financing line- note covenants*
3. *HTUA Governance Structure*
    - *Day to day operational financial decisions will be substantial*
    - *The ability to make quick decisions to maintain reliability*
    - *Models of other successful Arizona tribal utilities- Gila River, Aha Macav Power, Navajo Tribal Utility Authority or Tohono O'odham.*
    - *Ramifications of governance's structure to the Hualapai Constitution.*

5. Review HTUA simplified Expense/ Revenue Model

Mr. Cyr presented to the board for the second time a simplified expense revenue model for HTUA. Mr. Cyr indicated that he would present with the board assistant the same simplified/ revenue model to the Hualapai council when they meet.

Mr. Cyr also informed the board that the day to day operation of the electric utility will require that HTUA have the flexibility to make financial decisions that may exceed limitations imposed by the current HTUA board structure. The HTUA board and the council may want to consider changing the structure to be more aligned with other successful tribal utilities in the states such as, Gila River, Aha Macav Power, Navajo tribal utility authority or Tohono O'odham.

Mr. Vaughn and Mr. Davidson indicated that such a structure may require changes to the Hualapai Constitution. The board instructed Mr. Cyr to obtain the most recent Hualapai constitution for discussion at the next board meeting.

6. Project Update

a. Proposed Power Line to Grand Canyon West

1. Status of power line survey- Bobs Report

- *Mr. Becherer provided an update on the right of way work that has been performed to date. In summary the right of way consultants have laid out staking for the proposed transmission line routing. Kevin Davidson indicated that he is still waiting for some data from the right-of-way consultant that he can use to develop a more robust, dynamic map linked to google earth (GIS).*

2. Status of NEPA/ Environmental
    - BLM field trip (Kevin)
        - *Mr. Davidson had reported to the board the results from a recent field trip that included BLM, as well as cultural representative from the Hualapai's Cultural Resources Department. Mr. Davidson reported about half a dozen sensitive areas associated with the current routing, and provided detailed maps that depicted minor adjustments to the original proposed routing that could be used to avoid the sensitive areas. Additionally, Mr. Davidson indicated that the BLM was asking if the Diamond Bar Road Route offered an alternative route of consideration. Mr. Davidson explained to the board that the route had been considered and ultimately rejected due to cost, and a high incidence of private land requiring right-of-way. Mr. Peter Bungart, Cultural Resources Director, related to the board that even though the Diamond Bar route presents additional cost and private right away concerns, that the board may want to reconsider this route to avoided environment issues and cultural issues that were discovered during the field trip. Mr. Cyr and Mr. Davidson reminded Mr. Bungart and the board that the alternative paths for proposed routing on Tenney Ranch Road Route, should be sufficient to avoid the environmental and cultural sensitive areas identified during the recent field trip.*
3. Tucson Electric Power System Impact Study Dolan Springs to Grand Canyon West
    - *Mr. Cyr updated the board on the status of the study. We are still waiting to hear back about the final study parameters.*

- Other discussions with WAPA
    - *Mr. Cyr informed the board that he has had an initial discussion with WAPA regarding a new transmission line for the Hualapai Peach Springs customers that would originate from Round Valley substation. (see item 4 below) WAPA also indicated that there may be a possibility of grant money to pay for a system study associated with a Round Valley to Peach Springs transmission lines. Mr. Cyr will work with Mr. Davidson to research said grant money.*

4. Round Valley to Peach Springs Transmission Line?

b. Community- Scale Solar Array (Kevin)

- *Mr. Davidson reported to the board that based on the PPA proposed by MEC that the proposed solar project is essentially not economically feasible or desirable for the Hualapai tribe to pursue.*

c. Mohave Electric Cooperative discussions—Update

1. Discussions with MEC
    - *Mr. Cyr reported that no additional discussions have accrued with MEC*

7. Other matters

a. Update on tribal council actions (Kevin)

- *Mr. Davidson updated the board on his recent interactions at tribal council meetings.*

b. Cell tower AT&T (Kevin)

- *Mr. Davidson updated the board on a proposed AT&T wireless project that is under consideration by the Hualapai Council.*

c. New Board Member

- *Mr. Davidson updated the board that we have not received any applications for the open board seat on the HTUA board.*

d. Southwest Power Conference

- *Mr. Cyr informed the board about an upcoming southwest conference, after discussion Mr. Cyr and board member's will not be attending.*

e. Announcements

8. Set time and location for next meeting

Next meeting scheduled for August 14, 2018 at Hualapai Health, Education and Wellness Department.

9. Adjourn

Adjourned at approximately 11:00am.

Hualapai Tribal Utility Authority (HTUA) Meeting Minute

August 17th, 2018 Hualapai

Health Department Conference Room

1. **Call to Order**

   The meeting was called to order by Chairman Vaughn at approximately 9:12am.

2. **Roll Call**

   Board Members
   Charles Vaughn, Chairman- present
   Joe Montana, Vice Chairman- present @ 9:30
   Jamie Navenma, Secretary- via telephone
   Treasurer- Vacant
   Rory Majenty- via telephone

   Support Personnel and Guest

   Bill Cyr, General Manager

   Kevin Davidson, Planning Director

3. **Review and Approve Minutes from July 5th, 2018**

   Mr. Vaughn made a motion to approve July 5th, 2018 Board meeting minutes with a second by Mr. Navenma

4. **HTUA Meeting with tribal council**

   Mr. Cyr and Mr. Davidson briefed the Board on the recent meeting with Hualapai Tribal Council that occurred on July 26, 2018 in council chambers. In summary the following items were presented and discussed with council

   - *Revenue and expense forecast*
   - *Acquisition of MEC assets for Peach Springs*
   - *Impact of serving GCW load*
   - *Required additional load to break even*

- *Impact of Colorado River water pumping load (assumes water rights settlement)*
- *Other planned future developments by tribe- housing, casino, hotel…*
- *Update on GCW transmission line*
- *General routing discussions*
- *Right of way work to date*
- *Environmental work (Hualapai Cultural Dept/ BLM)*
- *Estimated cost*
- *How to pay for the line*
  - *Hualapai pay 100% cash*
  - *GCW pay 100% cash*
  - *Financing line- note covenants*

- *HTUA Governance Structure*
- *Day to day operational financial decisions will be substantial*
- *The ability to make quick decisions to maintain reliability*
- *Models of other successful Arizona tribal utilities- Gila River, Aha Macav Power, Navajo Tribal Utility Authority or Tohono O'odham.*
- *Ramifications of governance's structure to the Hualapai Constitution.*
- *Possible field trip to visit proposed routes with Tribal elders and other cultural representatives*

The HTUA Board had a general discussion on the meeting and felt that it may be a good idea to make periodic presentations on the progress of the Grand Canyon West transmission line every couple of months. In general the direction from the council was not specific other than to continue moving forward with project design and to bring back a final proposal for council consideration in the future.

5. Discussion of Constitution of the Hualapai Tribe

The board discussed the Hualapai Constitution provisions that appear to require modification for the Grand Canyon West project to go forward. Mr. Vaughn indicated that he sits on the committee responsible for recommending changes to the constitution and as such he will bring forward the HTUA Boards concerns regarding needed changes to support HTUA efforts

6. Proposed Power Line to Grand Canyon West

a. Status of power line survey

- **Alternative route matrix – Kevin Davidson**

The Board was provided with a copy of a constraint matrix for all of the Grand Canyon West Transmission line routes that are under consideration. Mr. Davidson went over the matrix which identified constraints by category such as Biological, Hydrology, and Cultural, visual, economics and many more. The Matrix will be used by HTUA, BLM and others to assist in evaluating feasibility of the different routes.

b. Discussion of meeting with BLM on July 27th

The Board was then presented with the minutes from a July 27, 2018 meeting with the BLM in Kingman. The major take away from that meeting is that the BLM is strongly suggesting that the Piece Ferry/Diamond Bar route be looked at very closely again. The BLM appears to prefer this route as it travels for the most part along an existing roadway. Other routes raise environmental issues that may be more difficult to overcome than those imposed by the Pierce Ferry/Diamond Bar route.

c. Status of NEPA/ Environmental

The Board was informed that environmental works proceeds slowly as the Pierce Ferry / Diamond Bar route is looked at again.

d. Tucson Electric Power System Impact Study Dolan Springs to Grand Canyon West

Mr. Cyr briefed the Board about the current status of the interconnection study with Uni-Source. His presentation included a review of recent communication between HTUA and UniSource regarding the study. Mr., Cyr informed the Board that this study represents an initial study and that additional monies will need to be expended to obtain a final design and final cost from UniSource.

e. Financing options

The Board was presented with general information and recent communications associated with potential funding sources as listed below. As we finalize the route selection and transmission line design the actual cost of the proposed line will become more firm. Once we have better cost estimates we will begin the process of finding someone to finance the project. This could be combination of cash, grants and loans.

Kevin indicated his concern and provided recent communication that we are at risk of losing the USDA grant monies already in place. The take away is that we need to continue to make progress or we will lose these grant monies.

1. **Rural Community Assistant Corporation**

2. **Department of Energy Financing**
3. **Update on $1,881,130 High Cost Energy Grant from USDA/RUS for Hualapai Indian Tribe, GCW interconnections**

f. **Pierce Ferry/ Diamond Bar**

1. **Route Discussion**

The Board was briefed on recent work surrounding the new review of the Pierce Ferry/Diamond Bar route, including on a recent field trip to review the Pierce Ferry/Diamond Bar route by Mr., Cyr and Mr. Davidson on August 11, 2018. The Pierce Ferry Diamond Bar route was traveled and photos were taken of road crossings and other signification power line route features. This information was provided to the Board and will be provided to the Mohave County Public Works Department and our transmission line design consultants. The Board was also briefed on discussions with the county for securing the use of the county ROW to locate the proposed transmission in. Once all necessary information is collected, we will be applying to the county for the right to locate poles in said ROW.

2. **Legal opinion on county ROW**

The Board was provided with a confidential memo from our legal representative- Patrick Black

7. **Federal Hydro Power/ WAPA**

The Board was presented with various correspondences as listed below regarding Federal Hydro Power Allocations and misc. correspondence from WAPA.

a. **FERC order BCP-F10- Motion to pay fee $ 1504.84**

On a motion by Mr. Vaughn and a second by Mr. Montana the Board approved 4-0 the payment of $1,504.84 to the Boulder Canyon Project for higher transitional costs than expected.

b. **New BCP rate schedule**

c. **Bureau of Reclamation- Pechanga benefitting agreement for Schedule D power**

d. **Greetings from WAPA Desert Southwest Customer Liaison**

e. Boulder Canyon Project Federal register notice

8. Other Matters

a. Update on tribal council actions (Kevin)

Mr. Davidson updated the Board on his recent attendance at council meetings

b. AT&T fiber optic – update- Kevin

Mr. Davidson updated the Board on the AT&T project. Mr. Vaughn recommended the right-of-way for the fiber optic line, which expired in 2014, be renegotiated.

c. Power Market historical and forward-looking prices

Mr. Cyr updated the Board on historical, current and forecasted power costs in the region.

d. New Board Member

The Board was informed that no one has applied for Board position. On a motion by Mr. Montana and a second by Mr. Vaughn the Board approved 4-0 to continue with the search until October 30th.

e. Announcements

9. Set time and location for next meeting

The Board set the next meeting date for September 13 at 9am in the small conference room at the Health, Education and Wellness Department.

10. Adjourn at 11:00 AM

Hualapai Tribal Utility Authority Board Meeting Minutes

September 13, 2018 @ 9:00AM

Large Conference Room Hualapai Health, Education and Wellness Dept

1. **Call to Order**

   The meeting was called to order by Joe Montana, Vice Chairman at 9:05 am.

2. **Roll Call**

   Board Members
   Charles Vaughn, Chairman - absent
   Joe Montana, Vice Chairman - present
   Jamie Navenma, Secretary - present via phone
   Treasurer- Vacant
   Rory Majenty- Present via phone

   Support Personnel and Guest
   Bill Cyr, General Manager, present
   Kevin Davidson, Planning Director, present
   Mike Jackson, IMEG , present via phone until item 5

3. **Review and Approve Minutes from August 17, 2018**

   The minutes of the previous meeting were reviewed and approved by the Board 3-0 on a motion by Rory Majenty with a second by Jamie Navenma.

4. **Proposed Power Line to Grand Canyon West**

   a. **Status of power line survey**

      The status of the power line survey was reviewed with the Board. In summary, no additional work on the survey was conducted due to new efforts focused on the Diamond Bar/Pierce Ferry route. The detailed review of this alternative route is being conducted at the request of the BLM office in Kingman.

b. **Status of NEPA/ Environmental**

The status of the NEPA/ Environmental work was reviewed with the Board. In summary, no additional work on the NEPA/Environmental was conducted due to new efforts focused on the Diamond Bar/Pierce Ferry route. The detailed review of this alternative route is being conducted at the request of the BLM office in Kingman.

c. **Status Tucson Electric Power System Impact Study Dolan Springs to Grand Canyon West**

The status of the Tucson Electric Power System Impact Study Dolan Springs to Grand Canyon West work was reviewed with the Board. Tucson has delayed study results until September 21, 2018.

d. **Status Pierce Ferry/ Diamond Bar**

i. County right of way request

ii. IMEG Work related to materials to be provided to county

The status of the data submittal to Mohave County regarding the new Pierce Ferry/Diamond Bad Route was presented to the Board. Specifically, the Board reviewed a memo from Steve Latoski of Mohave County detailing the nature of the information requested by the county. Kevin Davidson and Mike Jackson provided the Board with a copy of the requested data and went over the new routes;

- *Width of ROW*
- *Pole height*
- *Approximate location of poles in ROW*
- *Estimated road crossings*
- *Difficult locations like narrow right-of-way through the Joshua Park subdivision and the technical concerns arising from crossing the 345 KV and 500 KV transmission lines*

The Board directed Mr. Davidson and Mr. Cyr to seek approval and signature from the Hualapai Council chair before submitting any data request back to the county. The Board requested that any written correspondence be signed by the Hualapai Council Chair, Dr. Clarke and Mr. Cyr.

The Board entered into an off agenda discussion regarding a recent inquiry from Colin McBeath the new CEO of the Grand Canyon Resort Corporation regarding the use of solar at Grand Canyon West as a more cost effective solution than a transmission line. Mr. Cyr and Mr. Davidson will keep the Board informed regarding this request. At this time little is known about the proposal so it is difficult to make any concrete conclusions but the Board was concerned about:

- *What does the Hualapai Council want*
- *Reliability of the system*
- *Will batteries be large enough to survive through extended power outages or long periods of clouds*
- *System will be complex -who will service system*
- *Unlike a transmission line, it will be costly for the system to be expanded to meet expansion at Grand Canyon West*

5. **Financial**

   a. 2018 Budget YTD, year-end forecast, Draft 2019 Budget

Draft 2019 budget was presented to the Board for initial review. A more complete budget will be prepared for the next HTUA Board meeting where it will be considered for approval by the HTUA Board.

6. **Federal Hydro Power/WAPA/Other Power related**

   a. **New transmission rates CRSP**

   The Board reviewed correspondence from Department of Energy -CRSP regarding a new transmission rate.

   b. **New BCP rate schedule—WAPA Presentation**

   The Board reviewed correspondence and a presentation from WAPA -regarding proposed rate. changes to the base rate. The proposed 9 percent rate reduction should be in effect, if approved in January 2019.

   c. **Pechanga request to assign Pechanga representatives to BCP committees**

   The Board reviewed a request from Pechanga that we appoint representatives from their organization to various BCP committees. After discussion, the Board decided not to recommend appointment of any representation from Pechanga.

7. **Other Matters**

   a. **Update on tribal council actions (Kevin)**

   b. **AT&T fiber optic - update- Kevin**

   The Tribe will be looking into securing a grant to build the tower AT&T would need to mount their telecommunications equipment then the tribe would rent space on the tower to AT&T. The council is also looking for consultants experienced with determining lease value for ROW associated with the Fiber optic line crossing the reservation

   c. Replacement Board member Search

      i. Sheri YellowHawk

   The Board reviewed an application from Sheri YellowHawk to serve as a HTUA Board member ---the Board decided to refer this request directly to Hualapai Chair Dr. Clarke for his input on how to proceed.

d. **Announcements**

Jamie Navenma announced his plans to resign from the HTUA Board. He will supply a written notice after today's meeting

8. **Set time and location for next meeting**

   Next meeting date will be in the same location at 9:00 am on October 18,2018

9. **Adjourn**

Hualapai Tribal Utility Authority Board Meeting Board Meeting Minutes

October18, 2018 @ 9:00AM

Large Conference Room Hualapai Health, Education and Wellness Dept

1. Call to Order

   The meeting was called to order by Chairmen Charles Vaughn at 9:08

2. Roll Call

   Board Members
   Charles Vaughn, Chairman- present
   Joe Montana, Vice Chairman- present
   Secretary- Vacant
   Treasurer- Vacant
   Rory Majenty- via telephone

   Support Personnel and Guest
   Bill Cyr, General Manager
   Kevin Davidson, Planning Director
   Andy Whitefield –BLM For discussion regarding BLM transmission line route analysis only --- via telephone

3. Review and Approve Minutes from September 13, 2018

   The minutes were approved 3-0 on a motion by Mr. Vaughn and a second by Mr. Montana

4. Proposed Power Line to Grand Canyon West
   a. Status of power line survey
   b. Status of NEPA/ Environmental
      - *Item a and item b were discussed in detail with the Board and with Andy Whitefield of the BLM. Andy explained that the BLM is interested in determining the feasibility of the Diamond Bar Pierce Ferry route becoming one of the routes (primary or alternative). Andy indicated that he had phone calls into groups that may have opposition to the Diamond Bar route such as the friends of the Joshua Tree Forest. Additionally, he and his staff are prepared to move forward with visual impact assessments for both the Pierce Ferry Diamond Bar route and the Tenney Ranch route. Chairmen Vaughn reminded Andy that that as a government agency the BLM has to also consider the United States Trust obligation to Native American Tribes. Specifically any decision regarding routes must also consider these Trust responsibilities in*

addition to any other third parties concerns. To only consider environmental aspects of routes does not meet the government's Trust responsibilities back to the Hualapai Tribe. Andy indicated that he will look into this aspect of the route evaluation as his study work moves forward. Andy also indicated that the work he is performing will span many months perhaps not concluding until the third or 4th quarter next year. Andy then disconnected from the call in line and the Board meeting continued.

c. Status Pierce Ferry/Diamond Bar

i. County right of way request letter
ii. Proposed agreement from county
iii. Comment from legal-Patrick Black

Discussion below covers i, ii, iii

The Board then discussed the recent proposal from the county that would allow the HTUA to utilize the existing ROW on the Pierce Ferry Road at no cost in exchange for the Hualapai Tribe taking over the responsibility of the maintenance on the Diamond Bar Road. The Board agreed that such a decision was one that would have to be made by the Hualapai council and not by the HTUA Board.

Kevin and Bill discussed legal review that Patrick Black has performed on the proposed agreement from the county. In addition they explained to the Board that they are in close consultation with Phil Wisely the Public Services Director for the Hualapai Tribe. They will both continue to monitor the developments regarding the proposed exchange of services for the responsibility of maintaining the Diamond Bar Road but recognize that Phil and others will need to take the lead in this area. All three items listed below we discussed in detail with the Board.

d. Status Tucson Electric Power System Impact Study Dolan Springs to Grand Canyon West

Mr. Cyr informed the Board that the interconnection study results were still not available. He also informed the Board that Uni-Source Tucson Electric will be conducting further study work that will require a $50,000 deposit. This study work will be directed at determining final design and the costs of the specific equipment for the interconnection and the labor associated with installing said equipment to facilitate the interconnection.

5. Financial 2019 Budget proposal

    a. Budget letter request from Hualapai Council---Wanda

    The Board reviewed the 2019 Budget request letter from Wanda Easter. 2019 Budget request are due by October 22, 2018.

    b. 2019 HTUA Budget request –Handout

    The 2019 Budget request proposal was presented tohe HTUA Board for consideration.. Various items were discussed with a primary focus on the impact BLM will have on the project schedule. The project may not move forward quickly until BLM finalizes its preferred route. We are at the point with BLM for them to conduct visual impact assessment on poles and how they blend or do not blend into existing environment.

    After the discussion the Board approved a motion (3-0) recommending the 2019 Budget amount of $899,899 for approval by the Hualapai Tribe with the motion being made by Mr. Vaughn and a second by Mr. Montana.

6. Federal Hydro Power/ WAPA/Other Power related

    The Board then reviewed various pieces of correspondence related to the Boulder Canyon Project associated with the Hualapai's hydro allocation.

    a. BCP public information request
    b. BCP monthly Newsletter
    c. BCP 10 year plan

7. Other Matters

    a. Update on tribal council actions (Kevin)

    Kevin reported that he had not attended any recent Tribal Council meetings so he had nothing to report on.

    b. AT&T fiber optic easement and review of draft RFP – update- Kevin

    Kevin briefed the Board on a request for proposal he is working on. The RFP is for assistance in negotiating the terms of a ROW renewal associated with the existing fiber optic cable that crosses certain locations of the Hualapai reservation. He informed the Board that the RFP would be going out in the next week or so,

c. Replacement Board member Search

i. Board member resignation

The Board discussed the recent resignation of a Board member and the lack of progress of attracting any qualified applicants. Existing Board members will reach out to any potential candidates over the next month. The results of these efforts will be discussed at next Board meeting and a new direction for finding replacement Board members may be discussed at that time.

d. Announcements

i. Arizona Tribal Energy Association – meeting Notice

The Board reviewed the upcoming ATEA meeting. Mr. Cyr indicated that he might attend but was uncertain at this time. No other Board member committed to attendance at this time.

8. Set time and location for next meeting

The next meeting date was set for November 15 at 9:00 am at the Room Hualapai Health, Education and Wellness center.

9. Adjourn

Motion to adjourn was by Mr. Vaugh second by Mr. Montana. The Board voted 3-0 to adjourn.

Agenda for Hualapai Tribal Utility Authority Board Meeting Minutes

November 15, 2018 @ 9:00AM

Large Conference Room Hualapai Health, Education and Wellness Dept

1. Call to Order

   The meeting was called to order by Mr. Vaughn at 9:10am

2. Roll Call

   Board Members

   Charles Vaughn, Chairman - *Present*
   Joe Montana, Vice Chairman - *Present*
   Secretary- Vacant
   Treasurer- Vacant
   Rory Majenty - *Via Telephone*

   Support Personnel and Guest(s)

   Bill Cyr, General Manager - *Via Telephone*
   Kevin Davidson, Planning Director - *Present*

3. Review and Approve Minutes from October 18, 2018

   The minutes were approved 3 - 0 on a motion by Mr. Vaughn and a second by Mr. Montana

4. Proposed Power Line to Grand Canyon West
   a. Status of BLM work
      - *Mr. Cyr briefed the Board on the status of BLM Environmental related work. Mr. Cyr informed the Board that both he and Kevin Davidson had a conference call with BLM to gain a better understanding of the timeline for completion of BLM work. The bottom line is that BLM does not expect to have initial study work completed until May or June of 2019. We are, and the BLM are hopeful that the Environmental work will result in a Finding of No Significant Impact (FONSI). After the initial Environmental work is completed, there will be a need for several public comment periods, as well as public presentations. In the end, it looks like the earliest that construction could commence would be the beginning of the 4th quarter 2019. In parallel of the Environmental work, we will be working to secure the final Right of Way approval from the BLM, BIA, County and possible independent land owners. The actual Rights of Way obtained will be dependent on the preferred route selected.*

        With Board concurrence, Mr. Cyr and Mr. Davidson will re-emphasize the importance of the BLM completing its work and will also work with Tierra Right of Way so see if they might help expedite *the BLM work. Specifically, Tierra will help BLM expedite the current hurdle which is the visual impact of key observation points on both the Diamond Bar route and the Tenney Ranch/Hells Canyon route. The Board also authorized Mr. Cyr and Mr. Davidson to meet with the Friends of Joshua Tree, sooner than later.*

b. Status of power line survey

c. Status of NEPA/ Environmental

- *See discussion in 4a*

d. Status Pierce Ferry/Diamond Bar

- *Kevin Davidson then lead a discussion regarding the Pierce Ferry/Diamond Bar option. Mr. Davidson is in the process of determining if the power line along the Diamond Bar portion of this route can be placed in the road right of way. Mr. Davidson is working with the BIA to determine if an encroachment permit can be issued for this section. Mr. Davidson also informed the Board that there may be an existing right of way in Section 27 (land owned by a private 3rd party) that we may be able to utilize for this section of line. Mr. Majenty reminded the Board and Mr. Davidson that the Hualapai Tribe had donated a parcel of land for use by the Friends of the Joshua Trees. Finally, Mr. Davidson and the Board agreed that any discussions and approvals for the grant of easement along Pierce Ferry Road by the County will need to be negotiated and approved with the Hualapai Tribal Council's full cooperation and knowledge.*

e. Status Tucson Electric Power System Impact Study Dolan Springs to Grand Canyon West

i. Review Draft Study results

- *Mr. Cyr led a discussion on the preliminary Tucson Electric/UniSource system impact study. The initial findings determined that the existing Grand Canyon West electrical load can be serviced by the proposed new transmission line originating from the Dolan Springs substation. It appears a voltage regulating device - specifically a multi-stepped switched capacitor bank will need to be installed as part of the project. Tucson Electric/UniSource will finalize the study and forward to HTUA as soon as possible. Additionally, they will provide us a with a cost estimate to determine the system impact fees for Hualapai's share of developing the interconnection and capacitor bank. Specifically, they will give us a construction budget estimate for the interconnection work at Dolan Springs as well as HTUA's share of the proposed capacitor bank.*

f. Status Final Transmission Line/Substation Design

- *Mr. Cyr then informed the Board that the final transmission line design will not occur until final route selection is made. In recognition of the upcoming HTUA presentation* *to the Hualapai Tribal Council on Saturday, December 8, 2018 the Board wanted to make sure the following pictures were included in the presentation:*

- *Dolan Springs substation*
- *Intersection of Diamond Bar/Pierce Ferry Roads*
- *Tenney Ranch/Hells Canyon*

Additionally, the Board wanted Mr. Cyr to be prepared to discuss the following merits of a transmission line versus any solar power plant located at Grand Canyon West:

- *Ease of adding additional electrical load, like Casinos, Golf Courses, Hotels*
- *Reliability as it pertains to, what do you do when the Sun does not shine*
- *HTUA has already secured a 1.8 million grant to offset the cost of the transmission line*
- *The transmission line can be leveraged for future loop system from Dolan Springs to Grand Canyon West to Peach Springs and then back out to Round Valley (WAPA)*
- *The transmission line can be leveraged to supply the electrical requirements for the pumping stations required to pump water from the Grand Canyon up to the Hualapai Nation per the anticipated Hualapai Colorado River Water Allocation.*

g. Financing

i. Cooperative Finance Corporation

- *Mr. Cyr introduced the Board to a possible financing alternative The Cooperative Finance Corporation can be used to finance the entire project or to act as a construction loan provider prior to obtaining a long term financing package from the USDA or others.*

ii. DOE Webinar

- *Kevin Davidson informed the Board of a DOE financing Webinar which had already occurred.*

5. 2018 Annual Report

- *Mr. Cyr and Mr. Davidson presented a draft 2018 Annual Report for the Board. A motion to approve the Annual Report was made by Mr. Majenty and a second by Mr. Vaughn.*
  The Annual Report is scheduled to be presented to the Hualapai Tribal Council on Saturday, December 8, 2018. Mr. Cyr will have the draft report to Mr. Davidson by November 30, 2018.

6. Federal Hydro Power/ WAPA/Other Power related

i. WAPA Meeting Request

- *The Board was presented with a request to meet with WAPA leadership. The Board instructed Mr. Davidson to get back to WAPA and schedule the meeting with WAPA during our regularly scheduled Board Meeting on January 17, 2019.*

7. Other Matters

   a. Update on tribal council actions (Kevin)

      - *Mr. Davidson updated the HTUA Board regarding the proposed new cell towers by AT & T. The new cell towers will improve coverage and emergency response across the Hualapai Reservation. AT & T had proposed to the Council they would construct two (2) new towers and lease the land from the Hualapai Trible. The Council, in line with the HTUA goals and objectives, has directed HTUA and the Planning Department to look at the possibility of constructing the cell towers internally and then leasing space back to AT & T. Mr. Davidson and Planning's grant writer will look for funding and if found will apply for grants or other funding for this project on behalf of the HTUA.*

   b. AT&T fiber optic easement and status of RFP - update- Kevin

      - *Mr. Davidson updated the Board on the pending fiber optic right of way easement negotiations. The Council has asked HTUA and Planning to assist in this project. Mr. Davidson has completed a request for proposal and sent them to various firms that would be capable of providing the required assistance. The RFP proposals are due back on November 21, 2018. Mr. Davidson will provide any additional updates at the next scheduled Board meeting.*

   c. Replacement Board Member Search

      - *The Board requested that Mr. Davidson modify the qualifications for prospective board members. Specifically, the past experience requirements will be reduced to hopefully stimulate a more robust response from the Hualapai Community.*

   d. Announcements

8. Set time and location for next meeting

   - *Next meeting date was set for December 20, 2018 at 9:00am in the conference room at the Hualapai Health, Education and Wellness Center*

9. Adjourn

   - *Motion to adjourn was by Mr. Vaughn, second by Mr. Majenty. The Board voted 3-0.*

Agenda for Hualapai Tribal Utility Authority Board Meeting
December 20, 2018 @ 9:00AM
Hualapai Health, Education and Wellness Dept Conference Room

1. Call to Order – Meeting was called to order at 9:19am by Chairman Vaughn

2. Roll Call

   Board Members

   Charles Vaughn, Chairman – Present

   Joe Montana, Vice Chairman - Present

   Secretary- Vacant

   Treasurer- Vacant

   Rory Majenty – Via Telephone

   Support Personnel and Guest(s)

   Bill Cyr, General Manager – joined meeting at approximately 10:00am – was at Tribal Council Budget Meeting

   Kevin Davidson, Planning Director - Present

3. Review and Approve Minutes from November 15, 2018

   The minutes were approved as written 3 – 0 on a motion by Mr. Majenty and second by Mr. Montana

4. Discussion with Friends of Joshua Tree – invited (tentative)

   Board reviewed proposal by Friends of Joshua Tree to meet with BLM at the Kingman Field Office and agreed the Board should meet separately with them without the BLM staff present. The Board would like the HTUA to draft a formal request letter to Mr. Steffen to invite Friends of Joshua Tree to meet at another venue, possibly a restaurant in Meadview, Dolan Springs or Peach Springs.

5. Proposed Power Line to Grand Canyon West

   a. Status of BLM work

      Mr. Davidson updated the Board that the BLM has a new Archeologist and will be in the field in early January to establish the KOPs.

b. Status of power line survey

- Discuss Diamond Bar maintenance cost

  Mr. Davidson updated the Board on the issue surrounding the annual maintenance cost for the Diamond Bar Road. Mr. Cyr will contact Phil of the Public Works Department to obtain his estimate of what the maintenance costs would be.

- Discuss Clay Springs Alternative Route

  Mr. Davidson updated the Board that the Clay Springs Alternative has been relegated to a simple Class I analysis (literature review) in the EA in favor of the Pierce Ferry/Diamond Bar route which has been elevated from a Class I to the Class III analysis.

c. Status of NEPA/ Environmental

BLM and Tierra Right-of Way will be out on both the Diamond Bar and Tenney Ranch Route, working on environmental reconnaissance as well as development of KOPs. We have also received a BIA Encroachment permit application which we will review prior to the next board meeting.

d. Status Pierce Ferry/Diamond Bar

e. Status Tucson Electric Power System Impact Study Dolan Springs to Grand Canyon West

Mr. Cyr briefed the Board that Tucson Electric has indicated that the study is not complete and they continue to work on the final report.

f. Status Final Transmission Line/Substation Design

******At this juncture Mr. Cyr joined the meeting and presented the Board with a verbal presentation regarding the HTUA 2019 Budget. Mr. Cyr's presentation was based on information received at the Tribal Council meeting he had just left.***
Mr. Cyr informed the Board that the Tribal Council had only approved $250,000 of the $899,899 budgeted requested amount. Wanda will forward the final approved budget in the near future. The Council indicated that they reduced the requested amount to allow HTUA to spend additional time evaluating the merits of the following:

- *Prioritization of HTUA serving different portions of the reservation*
  - *Peach Springs*
  - *Grand Canyon West*
  - *Water allocation pumping requirements*

- *This prioritization will also include best route across the reservation*
    - *Primary feed from Dolan Springs*
    - *Primary feed from Round Valley substation*
    - *Primary feed from other WAPA substation*
- *For the above possible primary locations include alternative routes as well as potential for looped system.*
- *Evaluate the economics of the HTUA Electric Utility serving all electric requirements on the reservation*
- *Evaluate the economics of the HTUA Water Utility serving all water requirements on the reservation*
- *Evaluate the economics of the HTUA Wastewater Utility serving all wastewater requirements on the reservation*
- *Evaluate the economics of the HTUA Telecommunication Utility serving all telecommunications requirements on the reservation*
- *Final results will look at HTUA as a combined service provider for electric, water, wastewater, telecommunications*

Mr. Cyr would prepare an outline for use at the next HTUA Board meeting so that a more detailed strategic plan outline can be created so that all the information can be collected, collated and analyzed to satisfy this new request from the Tribal Council.

Note: The Council did indicate that the one-line item approved as-is is the continuation of the contract for Mr. Cyr to continue as General Manager of HTUA.

g. Financing

6. Hualapai Tribal Utility Authority Presentation of 2018 Annual Report to Hualapai Tribal Council

The Board was provided with the subject presentation. Mr. Cyr informed the Board that the Annual Report was not approved, pending approval of the final budget for HTUA.

7. **Federal Hydro Power/ WAPA/Other Power related**

The Board was informed that WAPA will be in attendance at the next meeting to discuss the CRSP Allocation. The Board was also provided information on a training session for Open Access Transmission Tariffs (OATT).

8. Other Matters

The Board was updated on the following items:

a. Update on tribal council actions – Kevin

b. AT&T fiber optic easement and status of RFP – update – Kevin

c. Big Chino Valley Pumped Storage Project

d. Arizona Tribal Energy Association (ATEA) Annual Meeting – January 23-24, 2019

e. Mohave Electric Cooperative – Recent outages affecting Peach Springs

f. Replacement Board Member Search

g. Announcements

9. Set time and location for next meeting

Next meeting date was set for January 17, 2019 at 9:00am in the conference room at the Hualapai Health, Education and Wellness Center

10. Adjourn

Appendix B: Cost of Service Study

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MEMORANDUM

DATE:	**MAY 18, 2018**	**PROJECT:**	HTUA COST OF SERVICE STUDY
TO:	Kevin Davidson		
FROM:	Patrick Bowman Melissa Davies		
SUBJECT:	Summary of Work Completed for HTUA Cost of Service Study		

InterGroup Consultants was retained by the Hualapai Tribal Utility Authority ("HTUA"), an entity of the Hualapai Tribe (the "Tribe"), to complete a "Cost of Service Study" to assist the Tribe in advancing the objective to provide electric service directly to its members.

Reports and presentations provided to estimate the cost to serve Peach Springs, and initial considerations for potential Grand Canyon West electricity services by the HTUA include the following documents, attached to this memo:

1. A summary memo dated July 27, 2017 with preliminary findings and issues after initial review of available cost of service information and previous studies.
2. A memo dated July 27, 2017 reviewing the 2007 and 2009 feasibility study inputs and assumptions and initial comparison to known MEC cost data.
3. A Review of Small Utility Comparables dated September 1, 2017 to understand cost structures, operations and rates for customers served by small utilities, usually municipally owned. The available cost breakdowns are compared to Peach Springs 2007 and 2009 feasibility studies and MEC comparable costs.
4. A presentation to the HTUA Board dated November 15, 2017 with preliminary findings on average rates for Peach Springs electricity served by HTUA.
5. A preliminary Report dated November 9, 2017 which the Board presentation is based on with cost estimates and methodology explained for HTUA serving Peach Springs.
6. An Updated Report, Dated December 11, 2017 with edited figures based on MEC provided data.
7. A summary of discussions InterGroup Consultants had with Western Area Power Administration (WAPA) and Mohave Electric Cooperative (MEC) on the subject of power supply considerations

and options for future Peach Springs and Grand Canyon West service. This includes discussions with:

a. Kevin Schaefer, Public Utilities (Rates) Specialist for WAPA Desert Southwest Region

b. Parker Wicks & Brent Oseik, Contracts and Energy Manager for WAPA Salt Lake City

c. John Paulsen, Manager of the Energy Management and Marketing Office for WAPA Desert Southwest Region

d. John Steward, Transmission Business Unit Manager for WAPA

e. Rick Campos, Manager of Engineering, Operations and Energy Services for MEC

8. WAPA Palo Verde Forward Prices from February 5, 2018 (provided by John Paulsen)

9. A memo, dated March 12, 2018 which sets out updated findings on cost estimates (specifically related to power supply interviews with WAPA and MEC), in preparing for the March 14, 2018 HTUA Board meeting compared to the preliminary November results presented to the Board.

10. A presentation dated March 15, 2018 intended for the Board meeting of March 14, 2018 (presentation received edits after the fact).

11. The forecast 5 year revenue requirement at existing assumptions for Peach Springs electricity serviced by HTUA for the years 2019 – 2023. This is based on the best known assumptions as of April, 2018 and reflects updates to power supply costs from the interviews conducted by WAPA and MEC.

12. An overview of the excel model data including data and assumptions used to calculate the forecast revenue requirement.

13. An embedded excel file, Forecast Cost of Service model, dated April 2018, which was prepared to analyze the cost estimates for an HTUA operation serving Peach Springs. The model provides a comparison of costs to service the utility needs under HTUA service compared to the current MEC service model and consists of a five year forecast revenue requirement, as well as input tabs which calculate the forecast revenue requirement and supporting tabs that provide the base data for the input tabs.

    a. Updates to the model that are not currently incorporated include:

        i. Updated net book valuations of distribution assets from MEC (to estimate acquisition costs). Currently data was provided by MEC at a gross book value and net book value was estimated in the 'Asset Replacement' tab of the model based on previous depreciation analysis done in the 2007 Feasibility Study and estimates on age of asset from MEC's 2016 Rate Change Application.

        ii. Acquisition Value/Capital Cost for Meters (not available for purchase by MEC).

        iii. There is only a nominal value estimate included for the cost of developing a new arrangement with MEC (wheeling power to the Nelson sub) and AEPCO (use of the Round Valley substation) to transmit electricity. At present a nominal value is incorporated ($10/year) to run the model (located in the 'Forecast Inputs' tab). As this would be a new arrangement there were no comparables available to estimate at this time.

1.0 Peach Springs Rate COS Summary Memo

InterGroup CONSULTANTS

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MEMORANDUM

DATE:	July 27, 2017	**PROJECT:**	P845
TO:	Kevin Davidson, HTUA		
FROM:	Patrick Bowman, Melissa Davies		
SUBJECT:	**Peach Springs Distribution Cost of Service**		

Attached is a memo to file reviewing the 2007 and 2009 feasibility study inputs and assumptions, and updating, where known, the data for the latest MEC filings and loads.

In short, the memo highlights the various assumptions and flags a few fairly major concerns about the feasibility of the concept.

First, on the positive side, it is noted that at least 3 other very small utility operations in the range of the Peach Springs size operate in the United States with rates that are in the range of what MEC charges (2 in Iowa and 1 in South Dakota). Obviously more would have to be known about these operations to know their cost makeup and how they operate (e.g., Iowa is known to have relatively low bulk power rates, so it's possible they keep the overall power cost low despite inefficiencies of a small distribution operation through savings on bulk power).

Second, since the time of the 2007 and 2009 studies, MEC's rates have seen considerable movement. Base rates increased over 2.5 cents/kW.h on average. This may assist in sustaining the earlier study conclusions regarding competitiveness with MEC's rates, as the benchmark may have become easier to reach. What has not been fully deciphered yet is the Power Cost Adjustment. At the same time as MEC's base rates increased 2.5 cents/kW.h, this "rider" has gone from zero (2006/07) to a 3.5 cents/kW.h charge (2008/09), to a 1.75 cents/kW.h refund (2015/16/17). It is unknown what if any rider will exist past 2017 at this time.

At its core, the memo highlights that at the current time, MEC's rates for the non-bulk power component (i.e., excluding generation and transmission) include approximately 1.6 cents for annual costs (operations, maintenance, and administration), 1.0 cents for asset related components (depreciation, interest, and taxes) and 0.2 cents for reserves. In effect, this sets out the benchmark that HTUA must meet to achieve competitive rates, assuming HTUA can acquire bulk power Freight on Board (FOB) at the Nelson substation at the same cost as MEC. This last assumption may be optimistic taking into account both power supply and transmission costs, but it may also be aided over time if HTUA can use hydro-electric power allotments to help bring down the average cost.

So the issue in this first pass becomes how likely it is that HTUA can develop a utility that can operate at 1.6 cents/kW.h for all operating costs, 1.0 cents for all capital related costs, and 0.2 cents/kW.h for reserves. Unfortunately, the latest MEC data does not support some of the 2009 study assumptions regarding large load growth in the commercial sector. Energy usage today remains at approximately 6.9 GW.h (well below the 9.6 GW.h assumed in the 2009 study) which means the operating cost budget could not exceed approximately $110,000 and the capital related component not exceed approximately $70,000, while providing $14,000 for annual reserves.

Assessing each area:

- On **operating related costs**, the 2007 study assumed that operating costs could be secured for in the range of $61,000 per year, and that Peach Springs would bear a share of overall administrative costs of $109,000. These values are in 2008 dollars so should at minimum be escalated for inflation. We have not tried to independently confirm the operating cost assumption, but do have concern with the administrative cost, which includes only $61,000 in total salaries (does not imply significant experience or backup for staff) and $5,000 each for accounting and legal (appears low). A further $31,000 was provided for "industry experts" which may be generous and help address tight budgets in other areas. In short, it is uncertain though not optimistic that HTUA could develop an operating utility with a budget limited to $110,000.
- On the **capital related costs**, the problems are larger. First, even the 2007 study did not show $70,000 to be sustainable within a few years of the assets being purchased. That 2007 study was based on paying only $210,000 for the assets (only $600 per customer, or less than 4 months' revenue, which is clearly low) and then reinvesting $200,000 per year for 4 years. However this study also notes that the system replacement cost is $3.8 million and indicates that much of it would need to be replaced relatively soon (asset average age in most asset classes was already near or beyond the normal useable life) so the $200,000 per year average investment appears potentially low. The 2009 study indicates MEC had spent further capital dollars in Peach Springs ($70,000) and that the capital cost estimate should be raised to $353,000. Using the GCW interest rate assumption midpoint (3%) even if capital costs had not increased from the $353,000 level to today's situation, and $200,000 was to be spent per year on reinvestment, the interest cost alone by year 4 ($1.153M in plant) would total $35,000. If the original purchase price is depreciated (or principal repayment over 10 years reflecting near end-of-life assets, and the new investment is depreciation on average over 45 years, then by year 4 depreciation/principal expense exceeds $53,000. Outside of any taxes or fees that might be payable, this totals over $88,000/year based on what are likely to be low capital cost assumptions.
- For **reserves**, we have no immediate way to assess the sufficiency of the specific $14,000 value, but given it is tied to what MEC assumes for their system we will assume it is within a reasonable range for that operating environment and utility asset conditions.

In short, outside of reserves, which we will assume are adequate in the above values, it appears unlikely that Peach Springs could be served at a cost comparable to MEC's rates, even with the optimistic assumption that bulk power (generation and transmission) could be secured for precisely the same cost as MEC achieves for its customers on average. Operating costs at $110,000 per year and capital related costs at $70,000 per year are unlikely to be achieved.

Further, the utility finance model above would consume almost all revenue from rates in direct annual costs of operations, administration, and interest, and leave very little surplus cash flow to finance the major reinvestment assumed ($200,000 per year – possibly more if the $3.8 million replacement cost must be incurred sooner than that pace of funding would suggest).

The issue of how the earlier studies found a feasible scenario are useful to summarize:

- In 2007, it was assumed that HTUA would make use of all available low cost hydro-electric power allocations (e.g., CRSP) without in any way recognizing with the lost revenue that arises if this power is used for Peach Springs rather than sold elsewhere (or used for GCW).
- In 2007 it was also assumed that the capital costs would total only $210,000.
- Finally, in 2007 the study did not show Peach Springs as a viable scenario – it was only when GCW was included, with an assumed major profit on the GCW component of the utility, that Peach Springs could be served competitively (in short, even in that analysis Peach Springs operated at a loss).
- By 2009, the feasibility analysis used a more realistic capital cost (buy out) value of $353,000, but concluded feasibility only based on a much higher load forecast (9.6 GW.h) that has not ultimately arisen (loads today only 6.9 GW.h).
- Further, feasibility in each case still required a rate increase of $85,000. While this was portrayed as a rate increase of 5-6%, this was only achieved by rolling in increases to Grand Canyon West loads. Based on solely Peach Springs' loads (which is likely the best assumption at this time, as GCW is not proving to have significant cost savings surplus to share with PS) the increases would have been measured to be more on the order of 15% or more.

We should find time to discuss how best to proceed. Development of rates is possible, but likely not within the scope of the project as first set out – that is, rates that can be competitive with MEC. Options involve a more thorough review of costs to seek reductions that are not yet apparent, options for government funded subsidies or lower-to-no-cost financing, and any other options that we could jointly identify. These options could include concurrent work undertaken by Rock Gap Engineering on the feasibility of community-scale solar with potential financing options including a DOE grant covering 50% of a 1 MW solar array or Net Market Tax credits.

2.0 Peach Springs 2007 & 2009 Feasibility Review

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MEMORANDUM

DATE:	July 27, 2017	**PROJECT:**	P845
TO:	File	**FILE:**	
CC:			
FROM:	Melissa Davies		
SUBJECT:	**DRAFT - Review of 2007 and 2009 Feasibility Studies, and updated date, re: purchase of Peach Springs distribution assets by Hualapai Tribal Utility Authority (HTUA)**		

1.0 OVERVIEW

The population base of the Hualapai Indian Tribe is located predominantly in Peach Springs, Arizona. Currently the area electricity distribution services are provided by Mohave Electric Cooperative (MEC). The Hualapai Tribal Utility Authority (HTUA) and Hualapai Tribal Council (HTC) on behalf of the Tribe has considered purchasing the distribution assets from MEC, in an effort to provide services to the Hualapai Reservation. A Feasibility study was undertaken in 2007 and updated in 2009 to determine the financial viability of HTUA purchasing and operating these assets. The 2007 and 2009 studies concluded that the purchase may be feasible and recommended the creation of a tribal utility authority to investigate further. The authority has now been created.

InterGroup was retained to provide a Cost of Service analysis for Peach Springs building upon the work of the earlier feasibility studies.

This memo reviews the methods used in the two feasibility studies in an effort to understand the conclusions made as well as discussion for financial and qualitative considerations to help guide a decision on purchasing these assets given the passage of time.

2.0 FEASIBILITY STUDY RESULTS AND COMPARABILITY TO MEC

The 2007 feasibility study undertook an analysis of asset condition and acquisition, operation costs and considerations, and electricity and transmission costs. The 2009 study provides an update for market and supply/demand considerations. Comparatively MEC filed a Rate Change Application for 2016 based on a test year ending December 31, 2015[1]. The costs on a total basis, and presented on cents per kWh basis are presented below in comparison to the 2007 and 2009 Feasibility results.

Table 1: Operating Cost Comparison for Peach Springs Feasibility Results vs. MEC 2015 Test Year (Dollars and cents/kWh)[2]

	2010 Forecast Year				2015 Test Year	
Peach Springs - Base Case	**2007 Study**	***2007 cents/ kWh***	**2009 Update**	***2009 cents/ kWh***	**MEC Adjusted Test Year**	***MEC cents/ kWh***
Power Supply (Generation)	337,509	*5.355*	582,314	*6.084*	51,416,541	*7.825*
Power Supply (Transmission)	119,916	*1.902*	191,998	*2.006*		-
OM&C - Distribution Related	50,206	*0.797*	105,554	*1.103*	3,909,283	*0.595*
OM&C - Customer Related	11,569	*0.184*		-	2,287,946	*0.348*
Administrative & General	113,974	*1.808*	127,400	*1.331*	4,156,695	*0.633*
Depreciation/Debt Service - Principal	8,290	*0.132*		-	3,032,902	*0.462*
Finance Expense/Debt Service - Interest	62,560	*0.993*	39,623	*0.414*	1,728,465	*0.263*
Other Expenses (tax)		-		-	1,596,432	*0.243*
Reserves	5,306	*0.084*	5,000	*0.052*	1,305,071	*0.199*
Total Projected Costs	**709,330**	***11.254***	**1,051,889**	***10.991***	**69,433,335**	***10.566***

The 2007 Feasibility Study estimates MEC projected costs on a per kWh basis of 11.254 cents/kWh. The 2009 Feasibility Update has a reduced forecast of 10.991 cents/kWh, this is largely due to increases in forecast energy consumption (more specifically industrial energy usage) that has not materialized as total costs increased from the 2007 Feasibility. Costs largely rose in the feasibility as a result of increased power supply costs. Increases in the acquisition cost of assets were offset on an annualized basis likely by decreases to the assumed interest rate (an annualized rate of 7.838% on a 30-year term basis was used to forecast in 2007; borrowing terms were not provided for the 2009 update). Comparatively, based on the recent MEC Rate Change Application, projected costs on a per kWh basis are 10.566 cents/kWh for the 2015 adjusted test year (based on actuals as filed in 2016).

Table 2 provides a comparison of forecast revenue to costs for HTUA in the 2007 feasibility study and 2009 update (using the base case for costs). It compares the MEC 2015 test year costs (proportioned to represent the Peach Springs specific cost allocation for comparison purposes[3]) with Peach Springs' related revenue based on actual 2016 load, with the approved 2017 MEC rate.

[1] MEC's 2016 Rate Change Application for test year ending December 31, 2015, Attachment 4, MEC FINANCIAL SECTION OF RATE AND COST OF SERVICE STUDY, Schedule C-1.0 Adjusted Test Year Income Statement for Year ending 12/31/2015 (pdf page 84 - of 251). Reserve set equal to operating margin consistent with fact that MEC is a co-op so income generated is re-invested in the utility (i.e. provides similar characteristics to explicit contributions to reserves).

[2] Total kWh used is consistent with feasibility studies for 2010 test year – 6.3 GWh in 2007 feasibility; 9.57 GWh in 2009 Feasibility Update. MEC 2015 Adjusted Test Year Operating Income, December 31, 2015 per Attachment 4, Schedule C-1.0. MEC cents/kWh calculation based on 2015 test year total system sales (before third party sales) of 657.1 GWh provided in Attachment 4, Schedule E-7.2 of Rate Change Application 7.26.16 (pdf page 134 of 251).

[3] 2015 MEC Test Year Weighted for 2016 Peach Springs Energy Sales approximates the amount of Peach Springs costs directly assigned to Peach Springs based on percentage of Peach Springs Energy to total MEC sales. The resulting amount $731,944 assumes costs are equivalent across all MEC service areas which is likely not fully accurate. 2016 actual load forecast is used with approved 2017 rates to represent expected revenues as a result of the most recent rate change.

Table 2: Revenue to Cost Comparison for Feasibility and MEC Test Year

	Revenue		Costs		*Difference*	
	$	¢/kWh	$	¢/kWh	***$***	***¢/kWh***
2007 Feasibility (2010 forecast year)	580,403	9.21	709,330	11.25	***-128,927***	***-2.05***
2009 Feasibility (2010 forecast year)	834,638	8.72	1,051,889	10.99	***-217,251***	***-2.27***
2015 MEC Test Year Weighted for 2016 Peach Springs energy sales	731,944	10.57	731,886	10.57	***58***	***0.00***

In the interim period since the 2007 and 2009 feasibility studies were conducted, total revenue collected from Peach Springs' customers has increased. However, expected utility costs have also increased.

Items that merit further consideration in order to fully test the 2007 and 2009 studies include the following:

- Power Supply assumptions that included contract arrangements that the HTUA may not now have immediate access to (including 2.8 million kWh supplied through the CRSP power supply arrangement that appears unavailable to the community until approximately 2025 under current contract. Note however that Section 6.1 of the NTUA benefit arrangement contract does provide an option for early termination, which requires Hualapai to give NTUA 12 months notice prior to termination of the contract. Under this provision, early access to the CRSP power supply arrangement may be available if economic);

- Asset condition and replacement costs that may underestimate the acquisition cost (if distribution network has since has major replacements) or underestimated the expected replacement cost that will need to take place in the near-term after acquisition;

- Operating, Maintenance and Construction (OM&C) forecast costs that were set to be comparable to MEC on a per kWh basis. This may underestimate the level of efficiencies MEC receives by operating on a much larger basis;

- Use of a Principal & Interest model for forecasting annual revenue requirement instead of the more commonly used method in utility rate making of annual depreciation added to annual finance expenses. Overall while the 2007 feasibility (at least) has equal annual forecast principal and interest payments, such that the total amount remains consistent over time, the 2009 study included no principal repayment. Even the 2007 approach will not fully capture within the revenue requirement the costs needed to maintain a reliable distribution utility (specifically, the model assumes the interest portion will slowly decrease in amount while the principal portion increases in the annual payment breakdown, consistent with full amortization – this approach to costing would not provide sufficient rates or cash to address depreciation, much less plant replacement and reinvestment). However the 2009 model is further concerning, it appears, by including no principal repayment during the term of the loan, nor depreciation in the cost structure (i.e., if a balloon repayment structure were assumed, this would provide no cash flow to make the balloon payment, and no surplus cash flow during the term of the loan for any needed utility reinvestment).

- o Inclusion of only a small reserve contribution (only $5,000 per year) which could lead to instability in rates if unforeseen costs occur (which is likely given asset condition).

2.1 REVENUE AND CUSTOMER LOAD FORECAST

The 2007 Feasibility study forecast total annual sales at 6.3 GWh for Peach Springs. This was largely from residential and small commercial energy sales, with two large commercial customers (with combined sales of 1 GWh. The 2009 Feasibility Update included a substantially increased load forecast due entirely to the addition of three new large commercial customers resulting in increased sales of over 3 GWh.

As seen in the graph below of Peach Springs actual energy sales, this large commercial customer growth has not materialized and actual energy usage has been mostly steady over the timeframe 2011 – 2016.

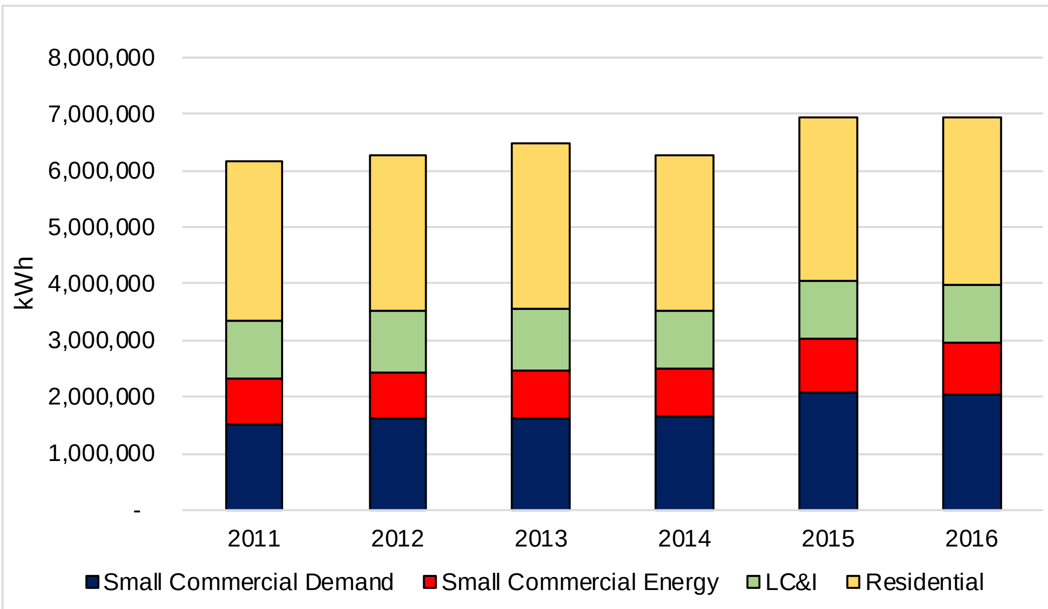

Figure 1: Total Peach Springs Actual Energy Sales (kWh) 2011 - 2016

Resulting actual and feasibility study forecast revenues are provided in the tables below – Table 3 uses base rates approved for MEC, Table 4 also includes Power Cost Adjustment riders. The Power Cost Adjustment rider appears to be a mechanism that allows MEC to defer actual power costs where these different (positive or negative) from that assumed when base rates were set. This means that the rider is likely a lagging indicator of the bulk power costs being experienced. This means that when new base rates are set, within some short period of time the rider would return to zero (since base rates should be tracking the new power costs) and then over time as power costs drift upwards or downwards, in time a new rider will be implemented to address any deferred balances in this account.

For comparability reasons, Table 3 is likely a better use for comparisons (particularly tied to Table 1 above) than Table 4. Streetlight loads are not included due to their inconsistent treatment in the earlier studies, and their relatively small overall load. Actual rates and riders charged to Peach Springs customers by MEC for the period 2007 to 2017 are provided in Table 5.

Table 3: Peach Springs Forecast Load, Revenue and Average Rates Comparison 2007 Feasibility, 2009 Update and MEC Actuals[4]

Load	2010 Forecast Year		Peach Springs Actual 2011	2012	2013	2014	2015	2016	2016
Rate	**2007 Feasibility (2010 forecast year)**	**2009 Feasibility (2010 forecast year)**	**MEC Average Rate (1991 approved rate)**	**MEC Average Rate (2012 approved rate)**	**MEC Average Rate (2012 approved rate)**	**MEC Average Rate (2012 approved rate)**	**MEC Average Rate (2012 approved rate)**	**MEC Average Rate (2012 approved rate)**	**MEC Average Rate (2017 approved rate)**
Residential									
kWh	2,933,587	2,995,894	2,812,349	2,770,117	2,912,868	2,755,143	2,898,656	2,960,536	2,960,536
revenue	$ 286,939	$ 294,576	$ 272,767	$ 337,699	$ 351,721	$ 336,675	$ 350,682	$ 357,375	$ 364,427
Average Consumers	377	362	340	340	342	344	344	347	347
Avg. Energy Rate (cents/kWh)	**9.78**	**9.83**	**9.70**	**12.19**	**12.07**	**12.22**	**12.10**	**12.07**	**12.31**
Small Commercial - Energy									
kWh	2,352,795	2,369,972	804,842	811,278	847,173	847,100	928,651	899,063	899,063
revenue	$ 219,514	$ 229,736	$ 75,779	$ 102,633	$ 107,310	$ 107,475	$ 117,128	$ 115,038	$ 117,480
Average Consumers	73	82	70	73	77	77	82	86	86
Avg. Energy Rate (cents/kWh)	**9.33**	**9.69**	**9.42**	**12.65**	**12.67**	**12.69**	**12.61**	**12.80**	**13.07**
Small Commercial - Demand									
kWh			1,522,180	1,627,182	1,634,968	1,643,650	2,090,987	2,058,822	2,058,822
revenue			$ 91,011	$ 132,451	$ 134,231	$ 135,640	$ 170,129	$ 168,087	$ 171,830
Average Load Factor			33.7%	35.5%	34.5%	33.6%	35.7%	35.4%	35.4%
Average Consumers			17	18	21	22	23	24	24
Avg. Energy Rate (cents/kWh)			**5.98**	**8.14**	**8.21**	**8.25**	**8.14**	**8.16**	**8.35**
Small Commercial - Total									
kWh	2,352,795	2,369,972	2,327,022	2,438,460	2,482,141	2,490,750	3,019,638	2,957,885	2,957,885
revenue	219,514	229,736	166,790	235,085	241,542	243,115	287,258	283,125	289,310
Average Load Factor	0.0%	0.0%	33.7%	35.5%	34.5%	33.6%	35.7%	35.4%	35.4%
Average Consumers	73	82	87	91	97	99	105	110	110
Avg. Energy Rate (cents/kWh)	**9.33**	**9.69**	**7.17**	**9.64**	**9.73**	**9.76**	**9.51**	**9.57**	**9.78**
Large Commercial									
kWh	1016712	4,205,027	1,033,200	1,072,400	1,086,160	1,029,360	1,027,680	1,008,080	1,008,080
revenue	$ 73,950	$ 310,326	$ 51,042	$ 81,653	$ 82,542	$ 78,690	$ 78,328	$ 76,982	$ 78,207
Load Factor	50.0%	50.0%	50.7%	53.8%	56.1%	50.7%	56.0%	54.4%	54.4%
Average Consumers	2	5	2	2	2	2	2	2	2
Avg. Energy Rate (cents/kWh)	**7.27**	**7.38**	**4.94**	**7.61**	**7.60**	**7.64**	**7.62**	**7.64**	**7.76**
Total									
kWh	**6,303,094**	**9,570,893**	**6,172,571**	**6,280,977**	**6,481,169**	**6,275,253**	**6,945,974**	**6,926,501**	**6,926,501**
revenue	**580,403**	**834,638**	**490,599**	**654,438**	**675,804**	**658,480**	**716,268**	**717,482**	**731,944**
Average Consumers	**378**	**363**	**341**	**341**	**343**	**345**	**345**	**348**	**348**
Avg. Energy Rate (cents/kWh)	**9.21**	**8.72**	**7.95**	**10.42**	**10.43**	**10.49**	**10.31**	**10.36**	**10.57**

[4] MEC average energy rate based on rates approved in Arizona Corporation Commission Decision No. 75931, dated January 13, 2017. Actual Peach Springs load and energy is used for kWh calculation for each year 2011 to 2016; as provided by MEC. Residential energy rate for MEC switched to a block rate structure for the 2012 rate (i.e. specific energy rate charged for first 400 kWh, a higher rate charged for next 600 kWh and the highest rate charged for any and all usage above 1000 kWh, see Table 5 for block rates charged by year). For simplicity, it is assumed 60% of load for residential is in the first block, 30% in second block and 10% in third block based on a cursory review of average annual use for this class in the 2013 year.

Table 4: Peach Springs Forecast Load, Revenue and Average Rates Comparison 2007 Feasibility, 2009 Update and MEC Actuals (with rate riders)[5]

			Peach Springs Actual						
Load	**2010 Forecast Year**		**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2016**
Rate	**2007 Feasibility (2010 forecast year)**	**2009 Feasibility (2010 forecast year)**	**MEC Average Rate (1991 approved rate w 2011 rider)**	**MEC Average Rate (2012 approved rate w 2012 rider)**	**MEC Average Rate (2012 approved rate w 2013 rider)**	**MEC Average Rate (2012 approved rate w 2014 rider)**	**MEC Average Rate (2012 approved rate w 2015 rider)**	**MEC Average Rate (2012 approved rate w 2016 rider)**	**MEC Average Rate (2017 approved rate w 2017 rider)**
Residential									
kWh	2,933,587	2,995,894	2,812,349	2,770,117	2,912,868	2,755,143	2,898,656	2,960,536	2,960,536
revenue	$ 286,939	$ 294,576	$ 326,787	$ 363,669	$ 351,975	$ 321,532	$ 312,890	$ 305,823	$ 312,618
Average Consumers	377	362	340	340	342	344	344	347	347
Avg. Energy Rate (cents/kWh)	**9.78**	**9.83**	**11.62**	**13.13**	**12.08**	**11.67**	**10.79**	**10.33**	**10.56**
Small Commercial - Energy									
kWh	2,352,795	2,369,972	804,842	811,278	847,173	847,100	928,651	899,063	899,063
revenue	$ 219,514	$ 229,736	$ 91,239	$ 110,239	$ 107,310	$ 102,745	$ 104,940	$ 99,304	$ 101,746
Average Consumers	73	82	70	73	77	77	82	86	86
Avg. Energy Rate (cents/kWh)	**9.33**	**9.69**	**11.34**	**13.59**	**12.67**	**12.13**	**11.30**	**11.05**	**11.32**
Small Commercial - Demand									
kWh			1,522,180	1,627,182	1,634,968	1,643,650	2,090,987	2,058,822	2,058,822
revenue			$ 120,249	$ 147,706	$ 134,231	$ 126,463	$ 142,685	$ 132,058	$ 135,800
Average Load Factor			33.7%	35.5%	34.5%	33.6%	35.7%	35.4%	35.4%
Average Consumers			17	18	21	22	23	24	24
Avg. Energy Rate (cents/kWh)			**7.90**	**9.08**	**8.21**	**7.69**	**6.82**	**6.41**	**6.60**
Small Commercial - Total									
kWh	2,352,795	2,369,972	2,327,022	2,438,460	2,482,141	2,490,750	3,019,638	2,957,885	2,957,885
revenue	219,514	229,736	211,488	257,945	241,542	229,208	247,625	231,362	237,547
Average Load Factor	0.0%	0.0%	33.7%	35.5%	34.5%	33.6%	35.7%	35.4%	35.4%
Average Consumers	73	82	87	91	97	99	105	110	110
Avg. Energy Rate (cents/kWh)	**9.33**	**9.69**	**9.09**	**10.58**	**9.73**	**9.20**	**8.20**	**7.82**	**8.03**
Large Commercial									
kWh	1016712	4,205,027	1,033,200	1,072,400	1,086,160	1,029,360	1,027,680	1,008,080	1,008,080
revenue	$ 73,950	$ 310,326	$ 70,888	$ 91,707	$ 82,542	$ 72,943	$ 64,840	$ 59,341	$ 60,566
Load Factor	50.0%	50.0%	50.7%	53.8%	56.1%	50.7%	56.0%	54.4%	54.4%
Average Consumers	2	5	2	2	2	2	2	2	2
Avg. Energy Rate (cents/kWh)	**7.27**	**7.38**	**6.86**	**8.55**	**7.60**	**7.09**	**6.31**	**5.89**	**6.01**
Total									
kWh	**6,303,094**	**9,570,893**	**6,172,571**	**6,280,977**	**6,481,169**	**6,275,253**	**6,945,974**	**6,926,501**	**6,926,501**
revenue	**580,403**	**834,638**	**609,164**	**713,322**	**676,058**	**623,683**	**625,355**	**596,526**	**610,730**
Average Consumers	**378**	**363**	**341**	**341**	**343**	**345**	**345**	**348**	**348**
Avg. Energy Rate (cents/kWh)	**9.21**	**8.72**	**9.87**	**11.36**	**10.43**	**9.94**	**9.00**	**8.61**	**8.82**

[5] MEC average energy rate based on rates approved in Arizona Corporation Commission Decision No. 75931, dated January 13, 2017. Actual Peach Springs load and energy is used for kWh calculation for each year 2011 to 2016; as provided by MEC. Residential energy rate for MEC switched to a block structure for the 2012 rate. For simplicity, it is assumed 60% of load for residential is in the first block, 30% in second block and 10% in third block based on a cursory review of average annual use for this class in the 2013 year.

Table 5: Peach Springs Actual Electricity Rates per Year as Charged by MEC (with rate riders) [6]

Peach Springs Actual Electricity Rates	2007 MEC 1991 approved rate w 2007 rider	2008 MEC 1991 approved rate w 2008 rider	2009 MEC 1991 approved rate w 2009 rider	2010 MEC 1991 approved rate w 2010 rider	2011 MEC 1991 approved rate w 2011 rider	2012 MEC 2012 approved rate w 2012 rider	2013 MEC 2012 approved rate w 2013 rider	2014 MEC 2012 approved rate w 2014 rider	2015 MEC 2012 approved rate w 2015 rider	2016 MEC 2012 approved rate w 2016 rider	2017 MEC 2017 approved rate w 2017 rider
Residential											
Monthly Service Charge ($/mth)	9.50	9.50	9.50	9.50	9.50	16.50	16.50	16.50	16.50	16.50	18.75
Energy Charge - First 400 kWh (cents/kWh)	0.08319	0.08319	0.08319	0.08319	0.08319	0.09008	0.09008	0.09008	0.09008	0.09008	0.08920
Energy Charge - Next 600 kWh (cents/kWh)	0.08319	0.08319	0.08319	0.08319	0.08319	0.10508	0.10508	0.10508	0.10508	0.10508	0.10420
Energy Charge - Over 1,000 kWh (cents/kWh)	0.08319	0.08319	0.08319	0.08319	0.08319	0.12008	0.12008	0.12008	0.12008	0.12008	0.11920
Energy Rider (cents/kWh)	0.00896	0.02583	0.03156	0.02450	0.01921	0.00938	- -	0.00558 -	0.01313 -	0.01750 -	0.01750
Small Commercial - Energy											
Monthly Service Charge ($/mth)	12.00	12.00	12.00	12.00	12.00	21.50	21.50	21.50	21.50	21.50	23.75
Energy Charge (cents/kWh)	0.08160	0.08160	0.08160	0.08160	0.08160	0.10335	0.10335	0.10335	0.10335	0.10335	0.10349
Energy Rider (cents/kWh)	0.00896	0.02583	0.03156	0.02450	0.01921	0.00938	- -	0.00558 -	0.01313 -	0.01750 -	0.01750
Total Energy Charge (cents/kWh)	0.09056	0.10743	0.11316	0.10610	0.10081	0.11272	0.10335	0.09776	0.09022	0.08585	0.08599
Small Commercial - Demand											
Monthly Service Charge ($/mth)	25.00	25.00	25.00	25.00	25.00	36.03	36.03	36.03	36.03	36.03	44.20
Billing Demand ($/kW)	8.25	8.25	8.25	8.25	8.25	$11.00	$11.00	$11.00	$11.00	$11.00	$11.00
Energy Charge (cents/kWh)	0.05374	0.05374	0.05374	0.05374	0.05374	0.07304	0.07304	0.07304	0.07304	0.07304	0.07371
Energy Rider (cents/kWh)	0.00896	0.02583	0.03156	0.02450	0.01921	0.00938	0.00000	-0.00558	-0.01313	-0.01750	-0.01750
Total Energy Charge (cents/kWh)	0.06270	0.07957	0.08530	0.07824	0.07295	0.08241	0.07304	0.06745	0.05991	0.05554	0.05621
Large Commercial & Industrial											
Monthly Service Charge ($/mth)	70.00	70.00	70.00	70.00	70.00	175.00	175.00	175.00	175.00	175.00	200.00
Billing Demand ($/kW)	9.75	9.75	9.75	9.75	9.75	10.98	10.98	10.98	10.98	10.98	10.98
Energy Charge (cents/kWh)	0.04558	0.04558	0.04558	0.04558	0.04558	0.06989	0.06989	0.06989	0.06989	0.06989	0.07051
Energy Rider (cents/kWh)	0.00896	0.02583	0.03156	0.02450	0.01921	0.00938	0.00000	-0.00558	-0.01313	-0.01750	-0.01750
Total Energy Charge (cents/kWh)	0.05454	0.07141	0.07714	0.07008	0.06479	0.07927	0.06989	0.06431	0.05677	0.05239	0.05301

[6] Rates for 2007 – 2011 as approved in Arizona Corporation Commission Decision 57172, rates from 2012 – 2016 as approved in Decision 73352 (effective September 1, 2012 but for simplicity purposes used for entirety of 2012 year), 2017 rates as approved in Decision 75931. Riders are annual average of monthly rate riders as provided by MEC for years 2007 – 2017. Residential block rate structure introduced in the 2012 residential rates (i.e. flat energy charge for residential customers from 1991 – 2011).

The tables above compare energy and load usage, revenue and average energy rates for Peach Springs by rate class. In general, the 2009 feasibility study, and to a lesser extent the 2007 feasibility, over-forecast the load requirements of Peach Springs for the time, resulting in higher forecast revenue and lower average energy rate than anticipated for the time period (2010 timeframe).

Since both feasibility studies were completed, MEC has raised electricity rates twice, in 2012 and recently in 2017. Actual Peach Springs load data from 2011 to 2016 was provided by MEC. Applicable rates approved in 1991 were used for the 2011 year (rates in place at the time of the 2007 and 2009 feasibility studies); the 2012 approved rates are used from 2012 to 2016. To get a sense of the most recent rate increase impacts, the 2017 approved rates are also shown with 2016 actual Peach Springs load.

In general, over the time period 2011 to 2016, Peach Springs has seen modest load growth, averaging at 2.3% per year. Largely this occurred between the 2014 and 2015 years likely due to the increases in the Small Commercial category. The latest data available is that there are perhaps 5-6 new or expanded accounts in the Peach Springs area in the Small Commercial category. These accounts may include the Hualapai Lodge, the high school (Music Mountain school), the juvenile detention & rehabilitation center (108 Highview Drive – which has a 10 MW solar array offsetting some load), hwy 66 Mile Post 96.4 pump house, and 525 Oak Street[7].

2.1.1 Other Revenue Assumptions – Power Sales Contracts

HTUA has access to a number of power contract arrangements. Presently, as Peach Springs is served through MEC, some power supply arrangements are contracted to third parties and locked in. Others are available for Peach Springs' immediate use if/when applicable.

MEC buys power from production utility Arizona Electric Power Cooperative (AEPCO) – predominantly coal power – three hundred miles southeast of Peach Spring (Cochise). Majority of what MEC buys is coal power. As alternatives that could be potentially available to HTUA, the following contract arrangements are noted:

- Supplemental Arizona Power Authority (APA) MEC Bill Credit - Tribe has hydro allocation of 108 kW of Hoover dam power (bill credit) transferred immediately through wire-to-wire connection (i.e. giving it to MEC for a credit on bills) – this is the main supply arrangement that will immediately impact rates in Cost of Service analysis

- BCP (Boulder Canyon Project) – through Western (Western Area Power Administration [WAPA]) and through Pechanga Band Of Luiseño Mission Indians - 382 kW power source is Hoover dam (schedule d1 from Western), since no benefit arrangement or utility to receive it, locked into a 5 year sale contract – cannot count on this low cost hydro power until 2021 (cannot buy out of contract until this time).

- CRSP (Colorado River Storage Project) - Salt Lake City area integrated project – 609 – 625 kW seasonal allocation – coming up for renewal in 2025 – equal to about $50,000/year – Western won't give same value in renewal.

At present only the APA arrangement is possibly available immediately. However, the earlier studies also assumed other HTUA power sources would be made available to supply Peach Springs, possibly from renewable energy development constructed on the reservation.

[7] Reconciled in conversation with Kevin Davidson since the former dialysis center has been converted into the Prosecutor's office, reducing the load and usage

The 2007 Feasibility study included for generation sources the CRSP power supply (2.8 million kWh with 609 - 625 kW of capacity), the Western Replacement Power (WRP) supply (2.64 million kWh – assumed to be purchased as required as provided for under the CRSP contract to meet load) and a 'supplemental' proxy price for the rest (1.5 million kWh with capacity peaking at 1,933 kW). Average cost at the meter ($/MWh) for 2009 was forecast at $36.99/MWh for the CRSP contract, $50/MWh for WRP, and supplemental power ranging from $87.36 - $113.42/MWh.

Total costs are shown in the table below (note 2010 values are not provided for CRSP & WRP and 2011 are not provided for the supplemental as pages are missing in the 2009 feasibility report so 2009 is shown, it is similar but doesn't perfectly reconcile).

Table 6: Power Supply Cost Breakdown for 2009 Forecast Year ($)[8]

2009 Forecast Year	Energy Cost	Capacity Cost	Transmission (Parker-Davis)	Total
CRSP	27,914	31,743	8,486	**68,143**
WRP	131,813			**131,813**
Supplemental	102,749	37,131		**139,880**
Total	**262,476**	**68,874**	**8,486**	**339,836**

In actuality, the CRSP allocation (which was included in the feasibility at a much lower price than supplemental power) is unavailable until approximately 2025 and would require additional wheeling costs from Glen Canyon Dam which may prove un-economic for direct use in Peach Springs.

The 2009 Update seems to assume same power supply methodology as the 2007 study. No further details are provided on methods.

Comparison of Purchase Power Costs between the 2007 and 2009 feasibilities is provided in the table below:

Table 7: Power Supply Cost Comparison 2007 to 2009 Feasibility (2010 Forecast Year)

2010 Forecast Year	2007 Feasibility	2009 Feasibility
CRSP Cost (includes WRP)	$201,319	$227,388
Supplemental Power Cost	$147,685	$354,926
Total	$349,004	$582,314

What is important to note about the power cost assumptions is that all allocations available to Hualapai are being used in one form or other to generate positive economic effects at present. Reallocation of any lower cost sources (e.g., CRSP), which are below the 7.8 cents/kW.h assumed in the MEC base rates, could lower the average cost of power to Peach Springs (if they can be economically wheeled to the service location) but this could only occur at the expense of the economic benefit they currently generate under their current allocation. This future "lost" value of transferring the power would need to be considered in the overall assessment of the feasibility of serving Peach Springs. The same constraint

[8] 2007 Feasibility, pages 125 – 126.

arises for new low cost resources such as solar – if solar can be developed at a low cost, presumably this can be done under MEC or HTUA ownership of the system. So the economic benefits of solar are not a means to lower rates under HTUA ownership any more than this same net revenue could be used to subsidize rates under MEC ownership. HTUA ownership only becomes more competitive to the extent a source like solar or CRSP can be used in a manner that is MORE economic under HTUA service to Peach Springs than it can be under the best available option absent HTUA ownership. Both sides of these transactions need to be taken into account.

2.1.2 Transmission / Wheeling costs

The 2007 Feasibility Study lists the following transmission and potential power supply providers within the vicinity of the Hualapai Indian Tribe:[9]

- Mohave Electric Cooperative [MEC] – current electricity providers. MEC owns the Nelson substation [69 kV] that distributes power to Peach Springs. The Nelson substation connects to a substation at Supai to the north east [transmission line travels along the eastern edge of the Hualapai Indian Reservation – owed by MEC]. Nelson substation also connects to the Round Valley Substation [APS] to the south. In addition, MEC brings power to the west side of Peach Springs via the Kingman Substation which is located along Interstate-40 at Blake Ranch
- Arizona Electric Power Cooperative [AEPCO] - AEPCo owns and operates the Apache Generating Station in Cochise, Arizona. The Apache Generating Station has a total of 605 MW of combined gross generating capacity [burns coal or natural gas].[10]
- Arizona Public Service Electric Cooperative [APS] - 500 kV power line that runs through the Hualapai reservation. The 500 kV power line runs from the Eldorado Substation to the Moenkopi Switchyard.[11] APS owns the Round Valley substation to the south of the Nelson substation, connecting MEC and APS.
- Unisource [UNSE] - connects to WAPA southeast of Peach Springs; point to point service on both WAPA's Parker Davis System and its Central Arizona Power System and a separate point to point service on WAPA's Intertie Power System and on its Central Arizona Power System again.[12] Current transmission contracts with WAPA totalling approximately 480 MW. The network service currently has Pinnacle Peak as a receipt point and Hilltop, Duval-Warm Springs, Planet Ranch, McConnico, and North Havasu as delivery points in Mohave County.[13]
- Calpine Corporation [CPN] - The power plant in operation in Arizona is the South Point Energy Center [combined cycle] with a total generating capacity of 530 MW.[14] The South Point Energy Center is located approximately 65 miles south west of Peach Springs.
- Western Area Power Administration [WAPA] - WAPA owns several 161 kV, 230 kV, 345 kV and 500 kV transmission lines and substations [including Hilltop and McConnico substations] in Mohave County.[15]

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9 2007 Hualapai Utility Authority Feasibility Report, page 146 of 146

10 Arizona Electric Power Cooperative, Power Generating Station, access July 24, 2017 at https://www.azgt.coop/electricity-generation-and-transmission/generation/arizona-electric-power-cooperative/

11 HTUA, November 30, 2015 Meeting Minutes, Page 5 of 9.

12 Unisource, 2017 Integrated Resource Plan, Page 73, accessed July 25, 2017 https://www.uesaz.com/wp-content/uploads/2016/04/UNSE-2017-Integrated-Resource-FINAL_reduced.pdf

13 Unisource, 2017 Integrated Resource Plan, Page 73, accessed July 25, 2017 https://www.uesaz.com/wp-content/uploads/2016/04/UNSE-2017-Integrated-Resource-FINAL_reduced.pdf

14 Calpine, Our Fleet. Accessed July 24 2017 at http://www.calpine.com/operations/power-operations/our-fleet

15 HTUA, June 11, 2015 Meeting Minutes, page 5 of 9.

- Salt River Project [SRP] - owns and operates a total of 13 generating stations throughout Arizona. Of relevance to the Hualapai reservation includes the Navajo Generating Station located near Coconino, Arizona [2,409.3 MW].[16]

The 2007 Feasibility Study assumes power will be delivered over one of the high voltage lines serving the Round Valley Substation, then consistent with current practise, over the MEC 69kV line to Nelson substation and from there over the 25 kV MEC system. HTUA would purchase ancillary services to deliver power to the Nelson substation.

The 2009 Update assumes the same path for power delivery. For purposes of the analyses it was assumed that the HTUA would purchase ancillary services to deliver power to the Nelson Substation. In addition to the high voltage transmission services, the HTUA would need to purchase and pay MEC for wheeling across its 69 kV and 25 kV systems. For the 2009 Update, it was assumed that the HTUA would pay MEC $2,000 per month for this wheeling service (approximately 0.25 cents/kW.h). It does not appear that MEC has a current wheeling rate but if one were developed it would be expected to be quite low given the very small proportion of transmission and distribution in MEC's cost structure.

Table 8: Power Delivery Cost Comparison 2007 to 2009 Feasibility (2010 Forecast Year

2010 Forecast Year	2007 Feasibility	2009 Feasibility
Transmission Delivery Costs	$27,294	$85,732
12 KV Distribution Delivery Costs	$81,881	$106,266
Total	$109,175	$191,998

2.2 ASSET CONDITION AND ACQUISITION COSTS

2007 Feasibility Study provided a valuation of the Peach Springs related distribution assets at $210,000, with additional $200k annually from 2007-2010 for equipment/replacement (not included in operation expenses other than in debt service category). No further assumptions were provided regarding asset condition/replacement costs to include in rate setting considerations. This total asset acquisition cost estimate was based on:

The 2007 Feasibility Study methodology considered the distribution assets necessary to serve the Hualapai reservation, excluding the substation, for the asset valuation. As maintenance records and MEC data was not available, proxy depreciation data from Nevada Power Company was used. Poles were visually examined through a field survey to determine the potential facilities included in an acquisition. This survey indicated approximately 7% due for replacement (in 5% condition). This assessment also applied to wood cross arms. The balance of the distribution system averaged 20% condition, estimating that 90% of poles and cross arms would be expected to be replaced during the next 9 years (i.e. 2008 – 2017). The physical appearance of the overall facilities was characterized with service life of equipment in the area ranging 15 to 50 years and the average age of poles, cross arms and conductors (excluding

[16] Arizona Power Plants, Accessed July 25, 2017 at http://www.powerplantjobs.com/ppj.nsf/powerplants1?openform&cat=az&Count=500

street light poles) at 50.4 years. The average age of the streetlight system was 8 years. Very few poles of recent vintage existed that were not associated with line extensions.

Looking at a range of valuation methods, an approximate valuation between $156,000 and $634,000 was established. Fair market value was narrowed to between $156,000 and $210,000 due to the substantial investment necessary in the system over the next 10 years. Assets valuation included the following:

Table 9: Peach Springs Asset Condition and Valuation (2007 Feasibility Assessment)

FERC	Description	Avg. Age	Adj Age	Useful Life	Deprec	RCN	RCNLD	OCLD
364	Poles	50.4	38	45	.844	1,437K	$223K	$19K
365	OH Conductors	50.4	40	45	.889	$1,577K	$175K	16K
366	UG Conduits	10	10	50	.200	$14K	$11K	$8K
367	UG Cable	10	10	35	.286	$24K	$17K	$13K
368	Transformers	50.4	34	42	.810	$452K	$86K	$33K
369	Services	20	20	30	.667	$198K	$66K	$38K
370	Meters	50.4	20	30	.667	$62K	$21K	$2K
373	Lights	8	8	20	.400	$59K	$35K	$27K
	Total					$3,820K	$634K	$156K

The 2009 Update study increased the acquisition valuation to an estimated fair market value of $353,000 stating that:

> 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 53 years. The average age of the street light system is 8 years. The overhead distribution system and rights-of-way continue to show signs of deferred maintenance. There are very few poles of recent vintage that are not associated with line extensions. Approximately $70,000 of new transformers and services have been installed since the 2007 inventory. Materials and labor, especially transformer costs have substantially increased over the past three years.[17]

In 2014, MEC with its subcontractor Alamon Utility Services, undertook testing and inventorying for power infrastructure on the Hualapai Reservation as part of a systems improvement, modernization and maintenance project to improve outage levels. This testing included GPS locating of electric facilities, pole testing and system inventory (including service of the line drops to the meters).[18] This testing resulted in

[17] 2009 Update Report, page 12 & 13 of 21.

[18] Letter from Hualapai Tribe Office of the Chairperson to Community members and residents of Peach Springs and Valentine, dated October 10, 2014 re: permission granted to Mohave Electric Cooperative/Alamon Utility Services to perform Power Pole Testing and System Inventory on Hualapai Tribal Lands

new service, preventative maintenance and emergency repairs on existing overhead and underground electric lines on the Hualapai Reservation in 2016.[19]

- From recent testing and inventory done, MEC should have a good understanding of asset conditions for the Hualapai Reservation power infrastructure. While some recent repairs have been undertaken the extent and cost associated is unknown at this time. Either MEC has replaced the majority of equipment (valuation will be much higher) or equipment needs to be replaced very soon (replacement costs will be very high in early years of operation) – either way, depreciation/capital will be very expensive in next 10-15 years.

More recent assumptions mentioned in discussions (not yet verified) estimate the asset acquisition costs closer to $0.5 – $1 million.[20]

Given the condition of the assets when last assessed (2009), it is clear that HTUA would incur increased costs for replacement of the distribution system, either in the upfront acquisition price if MEC has already begun replacing Peach Springs specific assets, or over the near-term after acquisition (if MEC has not yet replaced Peach Springs specific assets) due likely asset failure with the average age of distribution assets being well outside the useful life.

2.3 PEACH SPRINGS OPERATING COST CONSIDERATIONS

2.3.1 Operations, Maintenance & Construction 'OM&C' Costs

The 2007 Feasibility Study assumes the majority of administrative services will be served by third-party contractors. This includes:

- Certain operations, maintenance and construction services (operation, maintenance and construction to TUA, outage response maintenance, etc.), legal, consulting, advertising and accounting services, insurance (including liability insurance);
- Operational equipment (rolling stock and electric system operational equipment), special maintenance and repair equipment and major equipment test gear would be responsibility of third-party. This could include bucket trucks, digger derricks, tilt bed, wire reel, and pole trailers, pick up trucks, associated support equipment (air compressors, light plant, etc.);
- Supply, inventory and warehousing of materials and equipment handled by contractor;
- Third-party contractors will have responsibility for all facilities owned by TUA including transmission, overhead and underground distribution, street lighting system, solar and wind electric systems, metering, and service lines;
- System planning and equipment, operations and 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;
- Customer services to handle day-to-day functions and services outside normal business hours including customer call center, customer information system, billing and accounting system,

[19] Hualapai Tribal Nation Commercial Building Permit Application, June 14, 2016, Permit # 2016-049, Maintenance and repair of Electric Lines, Hualapai Tribal Lands
[20] In discussion with Kevin Davidson, request sent to MEC for asset value.

outage management system, and geographic information system would all be handled by a third party for at least the initial five years of operation.

Services not included in the pro forma financial forecast include energy efficiency educational materials and workshops, renewable energy system programs, pay-as-you-go card swipe metering, and establishing low income programs (in coordination with the Tribal Government).

Comparatively, MEC, the current electricity distribution providers for Peach Springs, benefits from efficiencies of scale and access to the skilled labour required for OM&C costs. Based on MEC's recent General Rate Application, OM&C costs were forecast at 0.943 cents/kWh for combined distribution related and customer related OM&C. To compare, this 2015 forecast for MEC would be approximately equal to $65,324 weighted by Peach Springs level of energy usage[21] or 8.9% of total operating costs. The 2007 feasibility forecast at $61,775 (approximately 0.980 cents/kWh and 8.7% of total forecast operating costs) and the 2009 update forecast at $105,554 (or 1.103 cents/kWh and 10% of total forecast operating costs). These values are provided as a component of total operating costs above in Table 1.

2.3.2 Administrative & General Costs

The study assumes some administrative costs will be done in house to handle day-to-day operation in the Peach Springs area, with a local office established within the TUA, integrated into the existing Tribal office. The report mentions a few enhanced services such as a new billing system (with options for levelized billing, pay-as-you-go card swipe system, scheduling on particular days), enhanced customer service (quicker response times, more efficient services & restoration). Equipment to purchase includes vehicles, telephone system, desktop computers and printers, copiers and fax machines, computer software, office furniture and possibly field communications equipment (possibly leased).

Annual forecast costs for the in house administrative services (assume this includes salaries & wages, benefits and system costs) is $113,974 in the 2007 Feasibility (1.808 cents/kWh). The 2009 update increases this allotment to $127,400 for the 2010 year (1.331 cents/kWh – only reduced because of increased load forecast).

The feasibility also flags this area for potential cost efficiencies as it is assumed the potential Grand Canyon West operation would use these same services without adding cost.

Comparatively, MEC's recent GRA forecasts Administrative & General costs at 0.633 cents/kWh, which would represent only $43,815 based on Peach Springs level sales.[22]

2.3.3 Debt Servicing Costs

The 2007 Financial Feasibility notably includes very small debt servicing costs in its forecast pro forma/revenue requirement calculation (approximately $70,000, or 1.1 cents/kW.h for interest and principal). The structure for financing built into the 2007 study is a 30-year loan at an annualized 7.838% interest rate, $210,000 withdrawn immediately to purchase Peach Springs assets, additional $200,000 annually from 2007 to 2010 for ongoing reinvestment costs.[23]

The Feasibility Study uses a fully amortized Principal & Interest model for forecasting annual revenue requirement instead of the more commonly used method in utility rate making of annual depreciation and

[21] 0.943 cents/kWh multiplied by 2016 actual Peach Springs energy sales of 6,926,501 kWh
[22] 0.633 cents/kWh multiplied by 2016 actual Peach Springs energy sales of 6,926,501 kWh
[23] 2007 Hualapai Utility Authority Feasibility Report, Base case debt service, pdf page 128 of 146.

finance expenses included in revenue requirement. This latter method better encompasses the principle of 'used and useful' – i.e. setting rates to recover annual cost levels that represents prudent acquisition of assets being used to serve customers.

The forecast loan repayment schedule included in the 2007 Financial Feasibility annual calculation of costs, is provided in the Table below. It includes both annual principal and interest recovery.

Table 10: 2007 Feasibility Study Principal Portion included in Debt Service Operating Costs ($ Dollars)

Year		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Borrowing - Facilities	210,000										
Borrowing - Equipment		200,000	200,000	200,000	200,000						
Loan Repayment Schedule		**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Loan Repayment Schedule		18,369	35,862	53,356	70,850	88,344	88,344	88,344	88,344	88,344	88,344
Year		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Loan Repayment Schedule		88,344	88,344	88,344	88,344	88,344	88,344	88,344	88,344	88,344	88,344
Year		**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Loan Repayment Schedule		88,344	88,344	88,344	88,344	88,344	88,344	88,344	88,344	88,344	88,344
Year		**2037**	**2038**	**2039**	**2040**						
Loan Repayment Schedule		69,975	52,481	34,988	17,494						

The 2009 Feasibility does not provide details on its financing structure. In general, annualized costs have increased as the asset acquisition valuation has between studies. However, it is assumed decreased interest rates were used given the economic condition changes between the initial 2007 and the 2009 update which would slightly offset the annual increase (down from 7.838% used in 2007). It is also not known what assumptions were used for equipment purchases (the 2007 feasibility includes annual purchases of $200,000 for 4 years after the initial acquisition). Treatment of GCW is also not known for the 2009 Update regarding debt servicing costs. The Table below compares the 2007 feasibility results with the 2009 update for the years provided.

Table 11: Annual Debt Service (P&I) Comparison 2007 to 2009 Feasibility Study Results ($)

Loan Repayment Schedule	2007	2008	2009	2010	2011	2012	2013	2014
2007 Feasibility - Debt Service Total (P&I	18,369	35,862	53,356	70,850	88,344	88,344	88,344	88,344
2009 Update - Debt Service Total (P& I)				39,263	57,117	74,611	92,104	109,598

The issue with this forecast is that, overall while principal and interest balance annually such that the total amount remains consistent, this is not going to capture within the revenue requirement the costs needed to maintain a reliable distribution utility. Specifically, the interest portion will slowly decrease in amount while the principal portion increases in the annual payment breakdown (shown in the sections below). Setting rates on the basis of cashflow type annual costs rather than an established annual cost to serve customers focuses narrowly on the short-term and can lead to rate stability and predictability issues for customers, especially for resource planning and for maintenance/replacements.

2.3.3.1 Depreciation/Principal Portion

The 2007 Feasibility Study includes a principal repayment in the annual revenue requirement calculation on the loans assumed to be withdrawn for the initial Peach Springs distribution asset acquisition and annual operating/maintenance costs.

These assumed terms result in the following approximate annual principal repayment portion built into annual revenue requirement (i.e. the level of costs that rates will ultimately be set to recover each year):

Table 12: 2007 Feasibility Study Principal Portion included in Debt Service Operating Costs ($ Dollars)

Year		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Borrowing - Facilities	210,000										
Borrowing - Equipment		200,000	200,000	200,000	200,000						
Resulting Repayment Schedule:		**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Principal Repayment		1,910	3,878	6,001	8,290	10,759	11,602	12,511	13,492	14,549	15,690
Year		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Principal Repayment		16,919	18,245	19,675	21,217	22,880	24,673	26,607	28,693	30,941	33,366
Year		**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Principal Repayment		35,982	38,802	41,843	45,122	48,659	52,472	56,585	61,019	65,802	70,959
Year		**2037**	**2038**	**2039**	**2040**						
Principal Repayment		58,152	45,216	31,266	16,222						

The forecast repayment costs increase annually until 2037, peaking at $71,755 in that year, assuming no other borrowings occur in the interim. As can be seen from the table, the annual principal portion or depreciation amount only cover a small portion of asset capital-related costs in the early years and an extensive portion in the latter years.

The biggest gap in this analysis is that customers will be paying off the acquisition value of these assets, as well as four years of equipment purchases for the next 30 years even though the majority of these assets have estimated useful lives (and remaining life values) well short of this timeframe (e.g., acquisition assets primarily likely have short remaining life, and some asset reinvestment may be for assets with shorter than average lives, such as trucks and computers). The result is an under recovery of asset costs in the early years of HTUA operations if rates were designed based on this feasibility. Future ratepayers will end up paying in rates for assets that were removed from service in years prior while also being charged for the replacement assets in use at that time.

MEC currently uses a more traditional method for revenue requirement – including annual depreciation expense based on the average service life for assets. For distribution assets this includes an average service life of 15-55 years made up of:

- 35 yrs for station equipment,
- 33 yrs for poles, towers, fixtures,
- 42-43 yrs for overhead & underground conduits, and
- 38 yrs for transformers.[24]

When setting rates, the principal/depreciation portion included in annual revenue requirement should appropriate the annualized cost of assets in service to avoid intergenerational inequities that in this case would serve to unduly discriminate future ratepayers.

As a result, it appears the 2007 feasibility study underallocates the amount of costs required for the principal portion/depreciation expense in its pro forma financial statement.

2.3.3.2 Finance Expense / Interest Portion

The interest portion included in the 2007 Feasibility study pro forma financials is based on 30-year loans at an annualized 7.838% interest rate, for $210,000 withdrawn immediately to purchase Peach Spring assets, additional $200,000 annually from 2007 to 2010 for ongoing equipment costs.[25]

[24] MEC 2015 Rate Change Application, Recap Schedule C-2.1 (pdf page 112 of 251), calculated as inverse of depreciation rate.

The resulting annualized interest payments included in the financial forecast are included in the Table below.

Table 13: 2007 Feasibility Study Interest Portion included in Debt Service Operating Costs ($ Dollars)

Year		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Borrowing - Facilities	210,000										
Borrowing - Equipment		200,000	200,000	200,000	200,000						
Resulting Annual Interest Expense:		**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Interest Expense		16,459	31,984	47,355	62,560	77,585	76,742	75,833	74,852	73,795	72,654
Year		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Interest Expense		71,425	70,098	68,669	67,126	65,464	63,670	61,737	59,651	57,402	54,977
Year		**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Interest Expense		52,362	49,542	46,501	43,222	39,685	35,872	31,759	27,324	22,542	17,385
Year		**2037**	**2038**	**2039**	**2040**						
Interest Expense		11,823	7,266	3,722	1,271						

While the inclusion of actual interest costs in revenue requirement per year will result in necessary cashflow to fund debt repayments (and avoid issuing further debt to pay existing debt), under this model any future borrowings will cause rates to increase notably from the full inclusion of interest costs in the early years of borrowing.

Neither the 2007 nor 2009 analyses provided pro forma financial statements showing the debt levels and cash flows associated with this assumption. While it is possible HTUA could operate bridging cash shortfalls with bond financing, analysis will be required to ensure that this does not result in spiralling debt levels with insufficient repayment, leading to a failure of the utility to be considered internally self-sufficient.

2.3.4 Treatment of Reserves/Operating Contingency

The 2007 Feasibility includes approximately $5,000 annual reserve/contingency contribution. power supply costs (generation & transmission). The report noted that especially in years of high capital investment (i.e. when system being replaced), adding reserve contribution can be difficult financially for ratepayers.

In general, a revenue requirement would want to ensure the amount of reserve allocations recovered through rates is tied to the level of ongoing risks the utility faces, potentially including cash flow considerations or future resource/capital requirements.

3.0 REVIEW OF OTHER JURISDICTIONS

A quick scan for comparable utilities in the US of the size considered for HTUA and the Peach Springs area shows very few utilities that operate with a size comparable to what the Peach Springs operation would be under HTUA ownership, as shown in the table below. Rates are not necessarily comparable given at least two of these utilities (Kotzebue and Fishers Island) appear to generate with diesel power. Nonetheless, for the others, there is some confirmation that rates for grid ties small utilities could be brought to a level close to what Peach Springs pays today (on the order of 10 cents on average). Further work would be required to confirm how these utilities operate and incur costs. For example, whether they

[25] 2007 Hualapai Utility Authority Feasibility Report, Base case debt service, pdf page 128 of 146.

operate as a stand-alone operation, or are just small cross-border operations tied to another utility in a neighbouring state.

Table 14: US Comparable Utilities to Peach Springs (HTUA)[26]

	Peach Springs (2007 Feasibility - 2010 Forecast Year)	Peach Springs (2009 Feasbility Study - 2010 Forecast Year)	Peach Springs (2015 Actual - with MEC rates approved 2012)	Kotzebue Electric Assn (Alaska) [2015]	Douglas Electric Coop (South Dakota) [2015]	Farmer's Electric Coop (Iowa) [2015]	Fishers Island Utility Co (New York) [2015]	Pleasant Hill Community Line (Iowa) [2015]
Ownership				Cooperative	Cooperative	Cooperative	Investor Owned	Cooperative
Revenues ($000s)	580.4	834.6	716.3	7,906.0	2,639.1	2,146.0	2,166.0	421.0
Sales (MWh)	6,303	9,571	6,946	19,889	22,754	16,842	6,032	4,497
Customers	452	449	345	1,268	814	761	759	116
Avg. Energy Rate (cents/kWh)	**9.21**	**8.72**	**10.31**	**39.75**	**11.60**	**12.74**	**35.91**	**9.36**
# of Employees					7	23		

[26] Data from US EIA Form EIA-861, Employment information from utility website where applicable: http://www.farmersrec.com/ and http://www.douglaselec.coop/

3.0 Review of Small Utility Comparables

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MEMORANDUM

DATE:	**SEPTEMBER 1, 2017**	**PROJECT:**	HTUA FEASIBILITY REVIEW
TO:	Kevin Davidson, HTUA		
FROM:	Melissa Davies		
SUBJECT:	Review of Comparable Small US Utilities		

1.0 OVERVIEW

The population base of the Hualapai Indian Tribe is located predominantly in Peach Springs, Arizona. Currently the area electricity distribution services are provided by Mohave Electric Cooperative (MEC). The Hualapai Tribal Utility Authority (HTUA) and Hualapai Tribal Council (HTC) on behalf of the Tribe has considered purchasing the distribution assets from MEC.

As a step in reviewing the feasibility of purchasing and operating a very small utility, other smaller utilities in the US were canvassed to get a sense for ongoing operating costs, maintenance requirements, cost structures, asset base and financing considerations. As the utilities canvassed are very small, there is not a lot of information available on them. Phone calls were made to the utilities with some information provided where known and available.

The utilities canvassed were all selected as the few comparators that could be found in the US with annual energy sales under 20,000 MWh. This is still much larger than Peach Springs estimated annual energy usage (around 6,000 – 7,000 MWh). Of the utilities canvassed 3 are much larger around the 20,000 MWh energy usage, two are approximately similar size (or smaller) to Peach Springs. The utilities include:

- Kotzebue Electric Association in Kotzebue, Alaska (20 GWh sales),
- Douglas Electric Cooperative in Douglas County, South Dakota (23 GWh sales),
- Farmer's Electric Cooperative in Kalona, Iowa (17 GWh sales),
- Fishers Island Electric Corporation in Fishers Island, New York (6 GWh sales), and
- Pleasant Hill Community Line in Pleasant Hill, Iowa (5 GWh sales).

Information found on these utilities are compared to the Peach Springs feasibility studies in 2007 and 2009 and MEC current cost information (weighted to approximately equal the amount apportioned to Peach Springs based on proportionate 2015 energy sales) in the table below. Written reviews on each utility are appended to this memo.

1.1 FINDINGS

Understandably, the three larger utilities have larger scale operations, including multiple salaried employees. All three of these utilities keep distribution maintenance staff on salary for emergency and outage requirements.

Three of these utilities – Douglas Electric, Farmer's Electric and Pleasant Hill were developed in the mid 1900s through the Rural Electric Cooperative initiative – largely to bring electricity to rural and farm land. Economies of scale seem to exist primarily as the asset base is old and paid off, replacement occurs as requirement (i.e. to failure) and grants helped fund the initial installation of distribution assets. The other two – Fishers Island and Kotzebue, are isolated communities.

While Fishers Island is similarly sized for energy sales as the Peach Springs area would be, as an isolated island it does not maintain the cost competitiveness that the HTUA is hoping to maintain under transfer of assets. Fishers Island, and Kotzebue (the other isolated utility) both have average energy costs much higher than MEC (which serves as a proxy for the rates HTUA would hope to achieve as a maximum limit), maintain their own generation sources (for Kotzebue this is the main source of power, for Fishers Island this is backup emergency power), and employ more full-time staff than under the 2007 and 2009 feasibility studies done for the tribe. As would be expected for an isolated utility, power supply costs make up a high portion of annual operating costs – approximately 60% for Fishers Island and 80% for Kotzebue. Fishers Island is transmitted electricity through two under-water submarine distribution cables. In a conversation on competitiveness with Kotzebue, the utility said specifically it is not competitive and the government subsidizes residential customer electricity rates through the Alaska Energy Authority (called power cost equalization payments – this is done to keep electricity prices manageable for Alaskan residents).Rate subsidization is a possibility for the HTUA to match MEC rates if funds are available and its deemed acceptable. This is not a short-term solution though, as subsidization would likely be required long-term to remain competitive.

The most comparable utility to Peach Springs for size and scale of operations is the Pleasant Hill Community Line in Pleasant Hill, Iowa. Pleasant Hill has no employees. The utility operates with one contract administrator/treasurer and contracts all operating, customer service and maintenance through the power supplier, Webster City. Pleasant Hill does not borrow any funds, all operating, maintenance and replacement is covered through annual operating and maintenance costs. In an emergency or outage situation, residents call the treasurer or the City of Webster (even the police) to report an outage and get service. Webster City has 8 fulltime and 1 part-time staff to maintain continuous service to customers and bulk purchases. All of this contracting is billed as incurred to Pleasant Hill along with power supply costs.

Pleasant Hill Community Line does not own or rent any buildings or space, does not own any trucks or tools and as a result has very little overhead. The Coop has a reserve large enough to handle replacement costs for approximately 50% of its asset base if required in an emergency (although it was mentioned that government assistance would eventually replenish some of these costs). Pleasant Hill tries to only raise rates if power supply costs increase; even though maintenance costs will greatly fluctuate year-to-year (as these completely cover any needed replacements). Assets are likely run to failure (no mention of inspections), was told assets were replaced "as required". As the area of coverage for the distribution assets is small, replacement requirements are identified during routine maintenance.

To date, contact has not been made with Farmers Electric Cooperative in Iowa and Douglas Electric Cooperative in South Dakota was not able to provide much background information relating to costs and asset base. Some information on these two utilities was available on their websites, shown below in the comparison table. As both utilities have larger scale operations than the Peach Springs area requires, comparisons to these utilities is not terribly relevant anyways.

	Peach Springs (2007 Feasibility - 2010 Forecast Year)	Peach Springs (2009 Feasbility Study - 2010 Forecast Year)	Peach Springs (2015 MEC actuals cents/kWh per Peach Springs energy sales)	Kotzebue Electric Assn (Alaska) [2015]	Douglas Electric Coop (South Dakota) [2015]	Farmer's Electric Coop (Iowa) [2015]	Fishers Island Electric Corporation (New York) [2015]	Pleasant Hill Community Line (Iowa) [2015]
Ownership				Cooperative	Cooperative	Cooperative	Investor Owned	Cooperative
Revenues ($000s)	$ 580	$ 835	$ 716	$ 7,906	$ 2,639	$ 2,146	$ 2,166	$ 421
Sales (MWh)	6,303	9,571	6,946	19,889	22,754	16,842	6,032	4,497
Customers	452	449	345	1,268	814	761	759	116
Avg. Energy Rate (cents/kWh)	**9.21**	**8.72**	**10.31**	**39.75**	**11.60**	**12.74**	**35.91**	**9.36**
# of Employees (salary)	2-3 est.	2-4 est.	n/a	12 - 2 linemen, 6 plant workers, 4 office staff	7 - 5 linemen, 2 office staff	4 - manager, 2 linemen, office manager	Est. 4-5 FT employees ($240k annual expenditures)	0
Contract Employees	Administrative services, maintenance, emergency response, customer services	Administrative services, maintenance, emergency response, customer services	n/a	(overhauls, electrician, accounting)	no (only as needed for underground line replacement)	no	Est. 3.5 contract employees ($172k total)	1 treasurer; ops., main. & emerg. contracted through Webster City
Operating & Maintenance Costs (approx - $000s)	$ 252	$ 278	$ 191	$ 1,581	n/a	n/a	$ 795	$ 237
Power Supply costs (approx - $000s)	$ 457	$ 774	$ 544	$ 6,325	n/a	n/a	$ 863	$ 184
Generation Source	Colorado River Storage Power, Western Replacement Power, supplemental power	Colorado River Storage Power, Western Replacement Power, supplemental power	Arizona Electric Power Cooperative	self-owned (11-12 MW diesel plant, installed wind power, 1.2 MW storage)	East River Electric (own transmission & substations). In turn purchase generation through Basin Electric & WAPA	Purchases from Iowa Electric	Purchase all power from City of Groton, CT. Avg. cost of $0.1167/kWh ($795k total for 2015); own two back-up generators (very old - 1.1 MW combined)	Purchased through City of Webster City (supplied by Combelt Power Cooperative)
Assetbase	$210k valuation for cables, transformers, meters, poles	$353k valuation for cables, transformers, meters, poles	n/a	n/a	431 miles of overhead line and 75 miles of underground line	102 miles of line, 628 meters, transformers	383 distribution transformers, 5.6 miles of submarine supply cables, 9 circuit miles of overhead and underground distribution cables ($5.4 million plant in service)	30 miles of distribution line, transformers, meters. Don't own any buildings (or pay rent), trucks or tools

APPENDIX – WRITE UPS & REFERENCES ON INDIVIDUAL UTILITIES

Kotzebue Electric Association

Phone: 1-907-442-3491 – spoke with general manager Matt Bergan (note: He knows Mike Ocko from NTPC) on August 25, 2017

From website: https://www.kea.coop/about/history/

- Started in 1950s, with loan contract and mortgage with the Rural Electrification Administration – includes generators and distribution assets.
- Focus on renewable sources of energy (including wind) to keep rural Alaska energy costs at reasonable levels (higher costs of fuel, declining state legislature support).
- 840 members, over 18,000 MWh/yr generated.

1. *Confirm size (19,889 MWh sales, 1,268 customers, revenues $7.9 million, average energy rate 39.75 cents/kWh), reach (in miles – seems like large service area) and asset base of utility (distribution assets book value – any owned transmission, generation)*

    - Confirmed mostly (wasn't sure on exact revenues)
    - Kotzebue, Alaska is 73.8 km^2 in size (30.2 sq. miles), the Electric Association services the entire city.

    a. *Power supply and transmission – own your own generators – do you purchase any power (supplemental?)*

        1. *Supply mix?*
        2. *Purchase Power Arrangements – do you have renewable energy components? Any beneficial arrangements with wind or solar in terms of power purchases? Any self-owned generation?*
        3. *How do purchase arrangements work, separate entities for transmission and generation?*

    - Own and operate own generation.
        - 11-12 MW diesel plant – redundancies (multiple units, don't run them all, for backup and growth). Located in middle of town.
        - Installed wind power – located at end of distribution feeder, includes 1.2 MW storage (950 kWh) battery power. Both installed 3-4 years ago, paid for by government grants.
        - Supply mix is 70-80% diesel, 20-30% wind – wind power helps reduce fuel costs (which are very high for the community)
    - No transmission technically (generation connected directly to distribution system)

    b. *Are there any public financial statements, rate applications, available for review?*

- Rates and cost filed with the Alaska Energy Authority due to power cost equalization (PCE) subsidies for rates – look this up
- Rates are deregulated from Regulated Commission of Alaska (Co-op, non-profit).

2. *Operating costs (annual costs?) and services (# of employees, any extra service offerings such as energy efficiency programs, etc.?)*
3. *Maintenance costs and structure (employees/contracted/response times/logistics)*
    a. *Ratio of generation and transmission costs to operating and distribution*
    b. *On contracting vs. employment - what is contracted out, where do you source contractors (local, through another electric utility, non-local?), are they on retainer, how are outages and emergencies dealt with?*

- Operating and Maintenance annual costs approximately 20% of total costs, 80% is generation/power supply (largely fuel costs, maintenance on generation, etc.).
- Annual costs approximately equal to revenues (non-profit).
- Employees – 2 linemen (distribution), 6-7 power plant workers (generation), 4 office staff (including general manager).
- Minimal contracting – for overhauls (generation manufacturer contracting), electrician and some accounting (auditing, year end financials, etc.)
- Two linemen are on-call 24/7 to respond to emergencies and outages

4. *How does Kotzebue remain competitive with larger utilities (economies of scale)? For example, do they participate in bulk purchasing, share staff with other small utilities, rely on some industry aggregate group, etc?*

5. *Asset investment framework*
    a. *How is infrastructure paid for – loans, grants, cash*
        1. *Does your company secure loans or do you have a backer/government/etc.?*
    b. *What financial targets, reserves, cash requirements does the utility use for rate setting?*

- From Rural Utilities Services (RUS) – rules on return for co-ops, reserve/contingency/earnings is calculated on a times interest earning ratio to ensure don't lose money and can pay borrowings.
- Obviously, due to recent investment in wind and solar, and ongoing generation costs there is some financing involved.
- Rate setting structure includes depreciation expense for covering annualized portion of capital expense.
- Not competitive – there is an electric subsidy in the state to keep electricity prices manageable and comparable but very high (this is done through Alaska Energy Authority) through power cost equalization payments.

6. Reliability standards imposed/maintained? What measurements are used?

n/a

Douglas Electric Cooperative – South Dakota

Telephone: 605-724-2323 or dougelec@unitelsd.com

Spoke to manager September 1, 2017
Note: very little information was provided in conversation.

From website: http://www.douglaselec.coop/

- 7 employees:
    - Manager/Line Superintendent
    - Lead Lineman
    - Journeyman Lineman
    - Journeyman Lineman
    - Journeyman Lineman
    - Staff Assistant
    - Cashier-Receptionist
- Douglas Electric Cooperative, Inc. is a rural electric cooperative incorporated in 1946.
- Douglas Electric has 616 members. There are 819 services on 431 miles of overhead line and 75 miles of underground line in Douglas County, South Dakota.
- Costs approximately equal revenue. As a co-op, if large enough net income hold onto funds for twenty years than return to customers (approximately $2.5 million costs per year)
- Wasn't sure of operating costs, maintenance or power supply costs in a year (couldn't get information from staff assistant/finance person 'Phyllis')
- No contract employment unless underground line replacement (construction equipment and construction for digging up line is contracted)
- Power Supply through East River Electric Cooperative – own transmission & substations. They in turn purchase electricity through Basin Electric and Western Area Power Administration (WAPA).

Confirm size (22,754 MWh sales, 814 customers, revenues $2.64 million, average energy rate 11.60 cents/kWh), reach (miles) and asset base of utility (distribution assets book value – any owned transmission, generation):

Approximately confirmed in conversation - "that seems about right"

Farmers Electric Cooperative Inc.- Kalona, Iowa

1-319-683-2510

Called and left messages for the manager (Warren McKenna) – Unable to get in contact as of September 1, 2017.

From website history section mostly: http://www.feckalona.net/history.html:

- Installed nearly 2 MW of solar (total)
- Located in a rural region in eastern Iowa – also the middle of an ‘Amish community’ – services include taking electricity out of a house and installing electricity in houses as a result
- Never had any government loans
- Buys electricity directly from Iowa Electric (since 1920s)
- 102 miles of line, 628 meters, 506 members (60 more customers expected this year through an agreement with Iowa Electric)
- Small employment size (4 employees) – manager, two linemen, office manager.
- Installed load management system

Fishers Island Utility Co (New York) –

Sent questions via email on 2017-08-23 (to President – Mr. Finan, jcfinan@fishersisland.net)

Phone # 1-631-788-7251 – tried calling a few times, left a message and emailed

http://fiuc.net/electric/

The Fishers Island Utility Company ("FIUC") holds substantial ownership interest in the three "operating" corporations (Electric, Telephone and Water) and provides management, office and payroll services to each as well as to the independent Fishers Island Development Corporation ("FIDCO). The Electrical, Telephone and Water corporations and their rates are fully "regulated" as public utilities by the New York State Public Service Commission ("PSC").

Fishers Island Electric Corporation owned 51% by FIUC (Fishers Island Utility Company – 872 votes) and 49% by FIDCO (Fishers Island Development Corporation – 838 votes).

Power today is provided by submarine cable with the exception of occasional emergency power provided by a diesel – powered backup generator. The generator is owned by the Connecticut power company but Fishers Island benefits from generating power during peak times which keeps the rates lower. Having an emergency generator on the island also is invaluable in the case of power loss from the mainland.

2011 Electric Corporation Financial Statements (does this make up 100% of utility or only the 51%?): http://documents.dps.ny.gov/search/Home/ViewDoc/Find?id=%7BB65B7F14-0819-4B29-AA99-BC3E526CED03%7D&ext=pdf

2015 Annual Financial Statements:
http://documents.dps.ny.gov/search/Home/ViewDoc/Find?id=%7B91434544-3204-4ABC-8028-4DCF35329AAE%7D&ext=xls

1. Confirm size (6,032 MWh sales, 759 customers, revenues $2.17 million, average energy rate 35.91 cents/kWh), reach (miles) and asset base of utility (distribution assets book value – any owned transmission, generation)

- Confirmed. Summer peaking (July/August) utility (tab 63).
- Fishers Island, New York is 10.6 km^2 (4.1 sq. miles) in size (9 miles long, 1 mile wid.), the utility services the island. 2 miles off the southeastern coast of Connecticut.
- Operating Statement for year ending December 31, 2015:

UTILITY OPERATING INCOME:	
1501. Operating Revenues (pp. 30-31)	$ 2,042,004
1502. Operation and Maintenance (pp. 34, 36-37)	1,488,841
1503. Depreciation	169,045
Total Operating Expenses	**1,657,886**
1505. Amortization of Plant Acquisition Adjustment (p. 10)	-
1506. Property Loss Chargeable to Operations (p. 12)	-
1507. Operating taxes (p. 21)	203,231
Total Operating Revenue Deductions	1,861,117
Net Operating Revenue	180,887
1508. Income from Plant Leased to Others (p. 38)	-
Operating Income*	180,887
1509. Other Utility Operating Income*	-
Total Utility Operating Income*	**180,887**
OTHER INCOME	
1521. Income from Non-utility Operations	
1523. Dividend Revenues (p. 12)	-
1524. Interest Revenues (p. 40)	-
1526. Miscellaneous non-operating Income	19,743
Total Other Income	19,743
Gross Income*	200,630
INCOME DEDUCTIONS:	
1530. Interest on Long-term Debt (p. 18)	10,059
1539. Income Taxes (p. 21)	66,898
Total Income Deductions	76,957
Net Income*	**123,673**
DISPOSITION OF NET INCOME:	
1540. Miscellaneous Reservation of Net Income (p. 40)	
Balance transfer to Surplus*	**$ 123,673**

Revenue by Rate class:

2015 Electricity Sales by Rate Class	Number of kw.h sold (b)	Total revenues (c)	Average net revenue* Cents (d)
1600. Residential Sales	4,183,554	$ 1,268,720	$ 3.30
1602. Commercial and Industrial Sales	1,250,671	298,080	4.20
1603. Public Street and Highway Lighting	61,800	11,500	5.37
1604. Other Sales to Public Authorities	598,199	152,169	3.93
1605. Sales to Other Electric Utilities			
1606. Sales to Railroads and Railways			
1607. Interdepartmental Sales			
1608. Other Sales		156,380	
Total Sales of Electric Energy	6,094,224	$ 1,886,849	$ 16.80
1610. Rent from Electric Operating Property		25,200	
1612. Customers' Forfeited Discounts			
1613. Sales of Water and Water Power			
1614. Servicing of Customers' Installations			
1615. Miscellaneous Electric Revenues		129,955	
Total Other Electric Revenues		155,155	-
Total Operating Revenues - Electric		$ 2,042,004	

a. Power supply and transmission – ownership or purchase arrangements?
    1. Purchase Power Arrangements – do you have renewable energy components? Any beneficial arrangements with wind or solar in terms of power purchases? Any self-owned generation?

Electricity purchases (Tab 39) of 6,809,499 kWh from City of Groton, CT (contract as of December 31, 2008) generated outside New York State, for $794,451 (or 0.1167 cents/kWh average energy price). This accounts for all electricity supplied (plus losses).

Have two generators for a total capacity of 1,100kW (tab 45). Only $5,778 in fuel expense for 2015 (see operating and maintenance expense table), seems like back-up generation. No overhead transmission lines in assetbase (i.e. transmission likely owned by power supplier and cost included in power purchases).

Station (a)	How driven** (b)	Maker (c)	Year installed (d)	Voltage (e)	Frequency (f)	Phases (g)	Number of Units (h)	Kw. each*** (i)	Total kw.*** (j)
Fishers Island	Shaft	General Electric	1957	2,400	60	3	1	750	750
Fishers Island	Shaft	Elec. Products	1965	2,400	60	3	1	350	350

2. How do purchase arrangements work, separate entities for transmission and generation?

b. Are there any public financial statements, rate applications, available for review?

2. Operating costs (annual costs?) and services (# of employees, any extra service offerings such as energy efficiency programs, etc.?)
3. Maintenance costs and structure (employees/contracted/response times/logistics)
   a. Ratio of generation and transmission costs to operating and distribution
   b. On contracting vs. employment - what is contracted out, where do you source contractors (local, through another electric utility, non-local?), are they on retainer, how are outages and emergencies dealt with?

Note: ‘Debts to Associated Company’ to FIUC appears to be for contract services (at least partially) for office services and management services (tab 42). Contract for this established in 1964. Total contract services through FIUC equals $156,217 in 2015 ($100,711 for office services, $55,506 for management services) calculated based on hourly rates. Covers most of debits through year but not all. Additional $15,680 on accounting/regulatory expenses (tab 43) not included in FIUC debts. These three figures are including in operating costs below.

Name of associated company (b)	Date of maturity (c)	Interest rate % (d)	Balance at beginning of year (e)	Credits during year		Credits during year (h)	Balance at end of year (i)
				Interest accrued (f)	Other debits (g)		
Fishers Island Utility Company	n/a	n/a	$ 33,976	$ -	$ 204,833	$ 183,246	$ 12,389

Operation & Maintenance Expense - Electric for year ending December 31, 2015	Amount	Percent of Total (%)
1700. Supervision and Labor	$ 522	0.04%
1710. Fuel	5,778	0.39%
1732. Maint. Materials, Supplies and Expenses	75	0.01%
1735. Rents	62,205	4.18%
1738. Electricity Purchased	794,451	53.36%
Total Production Expense	**863,031**	**57.97%**
1761. Supervision	32,232	2.16%
1762. Operation Labor	32,735	2.20%
1764. maintenance Labor	95,064	6.39%
1765. Labor on St. Lighting and Signal System	821	0.06%
1770. materials, Supplies and Expenses	1,678	0.11%
1771. Operation Supplies and Expenses	4,868	0.33%
1772. Main. Materials, Supplies and Expenses	12,449	0.84%
1773. St. Ltg. And Sig. Sys. Mtls., Sup. And Exp.	4,234	0.28%
Total Trans. And Dist. Expenses	**184,081**	**12.36%**
1781. Meter Reading	15,692	1.05%
1782. Accounting and Collecting	19,312	1.30%
Total Customers' Acctg. And Colltg. Exps.	**35,004**	**2.35%**
1791. Other General Office Salaries	100,711	6.76%
1793. General Office Expenses	30,488	2.05%
1795.1 Management and Supervision	55,506	3.73%
1795.2 Legal Services	19,301	1.30%
1795.3 Other Special Services	24,233	1.63%
1797. Regulatory Commission Expenses	15,680	1.05%
1798. Insurance, Injury and Damages	44,465	2.99%
1800. Other General Expenses	86,872	5.83%
1811. transportation Expenses	29,469	1.98%
Total Administrative and General Expenses	**406,725**	**27.32%**
Total Operation and Maintenance	**$ 1,488,841**	**100.00%**

Note: highlighted means contracted

4. How does Fishers Island Utility remain competitive with larger utilities (economies of scale)? For example, do they participate in bulk purchasing, share staff with other small utilities, rely on some industry aggregate group, etc?
    a. Older utility, asset replacement is minimal (seem to ride out asset lives – i.e. to failure), backup generation but long-term power purchase contracts, most of admin costs contracted through ownership utility. Highest cost is power purchases/production (roughly 60%)
5. Asset investment framework
    a. How is infrastructure paid for – loans, grants, cash
        1. Does your company secure loans or do you have a backer/government/etc.?

- 2015 liabilities (from balance sheet), no long-term debt. Current and Accrued Liabilities (tab 7):

Liabilities and other credits	Balance at end of year
1214. Debts to Associated Companies (Fishers Island Utility Company)	12,389
1220. Notes Payable (p. 13)	186,763
Bank of Rhode Island (4.58%, 6 years)	147,614
Bank of West (4.66%, 4 years)	9,410
Ally Financial (4.77%, 5 years)	29,739
1221. Notes Receivable Discounted (p. 13)	-
1222. Accounts Payable	61,464
1224. Dividends Declared (p. 28)	-
1225. Matured Long-term Debt (p. 18)	-
1227. Customers' Deposits (p. 16)	6,439
1228. Taxes Accrued (p. 20)	48,436
1229. Interest Accrued	104
1230. Other Current and Accrued Liabilities	-
Total Current and Accrued Liabilities	**315,595**

b. What financial targets, reserves, cash requirements does the utility use for rate setting?

(Tab 26) Reserve of $2.33 million (with $0.124 contributed in 2015 and $0.200 million distributed as common stock dividends)

6. Reliability standards imposed/maintained? What measurements are used?

n/a

Pleasant Hill Community Line – Pleasant Hill, Iowa

No website or online information found.

Contact information from Iowa Stray Voltage Guide: http://www.iowastrayvoltageguide.com/media/cms/IAEC_StrayVoltageGuide_pg14_4E351C8E0E110.pdf

1-515-826-3379 – spoke to the Treasurer on August 25. 2017
No email, public information, not regulated

1. *Confirm size (4,497 MWh sales, 116 customers, revenues $0.421 million, average energy rate 9.36 cents/kWh[1] - 10.3 cents/kWh for residential, 8.8 cents/kWh for commercial), reach (in miles – seems like large service area) and asset base of utility (distribution assets book value – any owned transmission, generation)*

- Confirmed approximate revenues of between $400-500k per year.
- Reach is approximately 30 miles of line.

    a. *Power supply and transmission – ownership or purchase arrangements?*
        1. *Purchase Power Arrangements – do you have renewable energy components? Any beneficial arrangements with wind or solar in terms of power purchases? Any self-owned generation?*
        2. *How do purchase arrangements work, separate entities for transmission and generation?*

- Power purchased and delivered through City of Webster City, which purchases power from Combelt Power Cooperative[2]:
    - The Line Department is responsible for the installation and maintenance of the electric distribution system for Webster City and surrounding areas which consists of both overhead and underground wire. The department does all tree trimming, meter testing, street light and traffic signal work for the City.
    - The city of Webster City also owns and maintains approximately 130 miles of rural line. We also sell power and in turn maintain the electric distribution system for the City of Woolstock, Pleasant Hill Cooperative and Cass Line Cooperative. We have also begun maintaining the electric lines for the City of Stanhope.
    - The 8 full time and 1 part-time meter tech/substation tech must work in all types of weather conditions, some extreme, to maintain continuous power to our customers. They are responsible for furnishing power from the City's three 20 megawatt substations to individual customers.
    - The City currently has 3,850 residential meters; 529 commercial meters and 12 industrial meters. All of the power supplied to these customers is purchased from Cornbelt Power Cooperative in Humboldt, Iowa.

    b. Are there any public financial statements, rate applications, available for review?

NO, not regulated.

2. *Operating costs (annual costs?) and services (# of employees, any extra service offerings such as energy efficiency programs, etc.?)*

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[1] Confirmed: http://www.webstercity.com/Ave%20revenue.pdf

[2] http://www.webstercity.com/departments/electric_(line).php :

- There are zero employees – all are contracted. All maintenance and upkeep (including emergency and outage response) is contracted through Webster City – the City bills the Pleasant Hill Cooperative for services. Treasurer (handles books) and billing all contracted too.
- Utility is a co-op, run to breakeven each year, annual costs equal approximately annual revenues – i.e. costs approximately equal $400-500k per year.
    - Couldn't get breakdown between power supply and operating costs (he didn't have his books with him). From Webster City website for electricity rates (http://www.webstercity.com/electric_rates.php):
    - Estimated operating & maintenance costs are approximately 56% or $237k/year of total annual costs based on total revenue (which is approximately equal to total annual costs) less calculated power supply costs using industrial rates as a proxy (which include a transmission demand charge) and a 40% load factor, consistent with mainly residential/small business use (as used in 2007 Hualapai Feasibility for residential load forecast calculations).

3. *Maintenance costs and structure (employees/contracted/response times/logistics)*
    a. *Ratio of generation and transmission costs to operating and distribution*
    b. *On contracting vs. employment - what is contracted out, where do you source contractors (local, through another electric utility, non-local?), are they on retainer, how are outages and emergencies dealt with?*

- All contracted through Webster City, who have 8 full time and 1 part-time meter tech/substation tech to maintain continuous power to customers.
- Emergency/outages are handled by calling either the treasurer (contract employee) or local police, who contact City for maintenance/emergency response.
- Annual maintenance costs include replacement, and capital expenditures in a year.

4. How does Pleasant Hill Co-op remain competitive with larger utilities (economies of scale)? For example, do they participate in bulk purchasing, share staff with other small utilities, rely on some industry aggregate group, etc?

- Own no property, buildings (including rent), trucks, tools, etc. All contracted through city. Total asset base is approximately 30 miles of distribution line (and poles, customer meters and transformers).
- Only raise rates if city power supply costs increase. Even though maintenance costs fluctuate year over year (depending on storms, outages, etc.). Government assistance in emergencies (although this sometimes takes a while before realized).
- Maintaining steady rates is a priority for the utility.

5. *Asset investment framework*
    a. *How is infrastructure paid for – loans, grants, cash*
        1. *Does your company secure loans or do you have a backer/government/etc.?*
    b. *What financial targets, reserves, cash requirements does the utility use for rate setting?*

- No loans, pay annually for capital costs (through annual operating & maintenance costs).
- Maintain a reserve approximately large enough to replace half "the line" in case of emergency before government assistance (and perhaps insurance?) kicks in.
- Not rate regulated, co-operative, owned by customers. Share rates with Webster City (although not on website).

6. *Reliability standards imposed/maintained? What measurements are used?*
    a. Not measured

Industrial Rate (using as proxy for bulk power rate with transmission fee):			
Power Supply Base Demand ($/kW)		$18.75	
Transmission Demand ($/kW)		$0.85	
Energy Charge (cents/kWh)		$0.03525	
Annual Power Supply Cost Calculation			
Annual Sales (kWh)		4,497,000	
Estimated Load Factor		40.0%	
Annual Customers		116	
Avg. Energy Rate (cents/kWh)		**4.08**	
Annual Power Supply Costs	**$**	**183,674**	*43.6%*
Annual Operating & Maintenance Costs	**$**	**237,326**	*56.4%*
Total Annual Revenue	**$**	**421,000**	*100.0%*

By comparison, the demand charge for MEC industrial customers for 2017 (with transmission costs included) is $10.98/kW with an energy charge (after refund rider) of $0.05301/kWh. There is additionally a monthly service charge of $200/month for large commercial and industrial customers of MEC.[3] Combined and based on a similar estimated load factor the average energy rate for MEC industrial customers is 6.01 cents/kWh.

Note: This table was developed based on Power Supply costs from Webster City website (using bulk power rate with transmission fee) and estimated load factor similar to that used for Peach Springs Feasibility (40%). It is an estimate. Rates found here: http://www.webstercity.com/electric_rates.php#.Wam1H7KGNpg

[3] 2017 rates as approved in Decision 75931. Riders are annual average of monthly rate riders as provided by MEC.

4.0 Cost of Service Draft Findings Presentation to HTUA Board

InterGroup CONSULTANTS

Cost of Service for HTUA Owned Distribution Utility

Preliminary Findings – Peach Springs

Presented to Hualapai Tribal Utility Authority (HTUA) Board Members, Personnel and Guests

November 15, 2017

Initial Assignment – Peach Springs

- InterGroup Consultants was hired in June 2017 to provide a revenue requirement and cost of service forecast to understand the feasibility of the Hualapai Tribal Utility Authority (HTUA) purchasing Peach Springs Distribution Assets from Mohave Electric Cooperative (MEC) to run a local distribution utility

Project Schedule

- Originally 4 month schedule. Wait times for data from MEC have caused delays in schedule.

- For Mid–November, Project is nearing completion for Peach Springs analysis (rate design step if required and report finalization remains)

Project Schedule

Phase	Description	June		July		August		September		October		November	
1	**Project Initiation, Review and Familiarization**												
	Contract Signed	✓											
	Discussion with Client re: Project Understanding and Deliverables	✓											
2	**Load Forecast and Revenue Requirement**												
	Request Data from MEC										✓		
	Receive Relevant Information from MEC												?
	Data Analysis and Reporting											✓	
	Review of Comparable Utilities Cost Structure							✓					
	Provide Preliminary Findings											✓	
3	**Cost of Service Analysis**												
	Analysis on Cost of Potential Utility (cents/kWh)											✓	
	Present Findings											TODAY	
4	**Develop and Assess Draft Rate Structure Options (if Required)**												
	Rate Design [development of rates]												
	Present Findings												
5	**Present Results to Council, Draft and Finalize the Document**												
	Prepare Report on Findings												
	Present Findings to HTUA Board (as required)											TODAY	
	Address comments from the client and Finalize Rate Structure												
	Finalization of Report												

Preliminary Conclusions

- Estimated Annual Revenue Requirement & Required Average One Time Rate Increase

	Revenue		Costs		*Difference*		Rate Increase Required
	$	¢/kWh	$	¢/kWh	***$***	***¢/kWh***	
2017 Estimate (without power supply rate reduction rider)	**828,452**	**10.26**	**1,082,430**	**13.41**	***-253,978***	***-3.15***	**30.7%**
2017 Estimate (with power supply rate reduction rider)	**687,172**	**8.51**	**941,151**	**11.66**	***-253,978***	***-3.15***	**37.0%**
2007 Feasibility (2010 forecast year)	580,403	9.21	709,330	11.25	*-128,927*	*-2.05*	22.2%
2009 Feasibility (2010 forecast year)	834,638	8.72	1,051,889	10.99	*-217,251*	*-2.27*	26.0%

- Results indicate that 31% average rate increase required for HTUA profitability in year 1 (37% if include 2017 adjustment to rates for reduced power supply costs currently applied to electricity bills)

Total Projected Costs Summary – at 2016 MEC Approved Power Supply Costs

Peach Springs Annual Revenue Requirement	2019 Test Year: MEC Adjusted Test Year	2019 Test Year: MEC cents/ kWh	2010 Forecast Year: 2007 Study	2010 Forecast Year: 2007 cents/ kWh	2010 Forecast Year: 2009 Update	2010 Forecast Year: 2009 cents/ kWh
Power Supply (Generation)	$ 631,693	7.82	$ 337,509	5.35	$ 582,314	6.08
Power Supply (Transmission)	$ -	-	$ 119,916	1.90	$ 191,998	2.01
OM&C - Distribution Related	$ 96,000	1.19	$ 50,206	0.80	$ 105,554	1.10
OM&C - Customer Related	$ -	-	$ 11,569	0.18		-
Administrative & General	$ 150,000	1.86	$ 113,974	1.81	$ 127,400	1.33
Asset Replacement	$ 155,000	1.92				
Depreciation/Debt Service - Principal	$ 27,538	0.34	$ 8,290	0.13		-
Finance Expense/Debt Service - Interest	$ 22,199	0.27	$ 62,560	0.99	$ 39,623	0.41
Other Expenses (tax)	$ -	-		-		-
Reserves		-	$ 5,306	0.08	$ 5,000	0.05
Total Projected Costs	**$ 1,082,430**	**13.41**	**$ 709,330**	**11.25**	**$ 1,051,889**	**10.99**

- Total Projected Expenses $1.082 million per year (not including a return or any retained earnings)

Total Projected Costs Summary – Adjusted for Reduced 2017 Power Supply Costs

	2019 Test Year		2010 Forecast Year			
Peach Springs Annual Revenue Requirement	**MEC Adjusted Test Year**	**MEC cents/ kWh**	**2007 Study**	**2007 cents/ kWh**	**2009 Update**	**2009 cents/ kWh**
Power Supply (Generation)	$ 490,414	6.07	$ 337,509	5.35	$ 582,314	6.08
Power Supply (Transmission)	$ -	-	$ 119,916	1.90	$ 191,998	2.01
OM&C - Distribution Related	$ 96,000	1.19	$ 50,206	0.80	$ 105,554	1.10
OM&C - Customer Related	$ -	-	$ 11,569	0.18		-
Administrative & General	$ 150,000	1.86	$ 113,974	1.81	$ 127,400	1.33
Asset Replacement	$ 155,000	1.92				
Depreciation/Debt Service - Principal	$ 27,538	0.34	$ 8,290	0.13		-
Finance Expense/Debt Service - Interest	$ 22,199	0.27	$ 62,560	0.99	$ 39,623	0.41
Other Expenses (tax)	$ -	-		-		-
Reserves		-	$ 5,306	0.08	$ 5,000	0.05
Total Projected Costs	**$ 941,151**	**11.66**	**$ 709,330**	**11.25**	**$ 1,051,889**	**10.99**

- Annual Projected Cost reduced to $941,151 (from 2017 generation cost reduction applied by MEC to electricity bills as a rate rider) – has corresponding revenue reduction

Revenues

- Revenue at 2017 MEC rates & 2016 actual usage $828,452
- Assumes no load growth
- 3% Load Growth increases sales revenue by $20,000/year

Load	2010 Forecast Year		Peach Springs Actual 2015	Peach Springs Actual 2016	2016
Rate	**2007 Feasibility (2010 forecast year)**	**2009 Feasibility (2010 forecast year)**	**MEC Average Rate (2012 approved rate)**	**MEC Average Rate (2012 approved rate)**	**MEC Average Rate (2017 approved rate)**
Residential					
kWh	2,933,587	2,995,894	2,985,476	3,031,212	3,031,212
revenue	$ 286,939	$ 294,576	$ 362,083	$ 366,476	$ 373,774
Average Consumers	377	362	359	358	358
Avg. Energy Rate (cents/kWh)	**9.78**	**9.83**	**12.13**	**12.09**	**12.33**
Small Commercial - Energy					
kWh	2,352,795	2,369,972	1,011,152	970,178	970,178
revenue	$ 219,514	$ 229,736	$ 127,203	$ 123,957	$ 126,573
Average Consumers	73	82	88	92	92
Avg. Energy Rate (cents/kWh)	**9.33**	**9.69**	**12.58**	**12.78**	**13.05**
Small Commercial - Demand					
kWh			2,090,987	2,058,822	2,058,822
revenue			$ 170,129	$ 168,087	$ 171,830
Average Load Factor			35.7%	35.4%	35.4%
Average Consumers			23	24	24
Avg. Energy Rate (cents/kWh)			**8.14**	**8.16**	**8.35**
Small Commercial - Total					
kWh	2,352,795	2,369,972	3,102,139	3,029,000	3,029,000
revenue	219,514	229,736	297,332	292,044	298,403
Average Load Factor	0.0%	0.0%	35.7%	35.4%	35.4%
Average Consumers	73	82	111	116	116
Avg. Energy Rate (cents/kWh)	**9.33**	**9.69**	**9.58**	**9.64**	**9.85**
Large Commercial					
kWh	1016712	4,205,027	2,146,120	2,012,920	2,012,920
revenue	$ 73,950	$ 310,326	$ 163,939	$ 153,827	$ 156,275
Load Factor	50.0%	50.0%	48.6%	53.3%	53.3%
Average Consumers	2	5	4	4	4
Avg. Energy Rate (cents/kWh)	**7.27**	**7.38**	**7.64**	**7.64**	**7.76**
Total					
kWh	**6,303,094**	**9,570,893**	**8,233,735**	**8,073,132**	**8,073,132**
revenue	**580,403**	**834,638**	**823,354**	**812,347**	**828,452**
Average Consumers	**378**	**363**	**360**	**359**	**359**
Avg. Energy Rate (cents/kWh)	**9.21**	**8.72**	**10.00**	**10.06**	**10.26**

Forecast Costs: Asset Purchase

		2017 MEC Data	2007 Valuation Acc. Depreciation Weighting		
Code	**Distribution Asset Category**	**Quantity (#)**	**Gross Book Value ($)**	**Estimated Accumulated Depreciation (2007 Report %)**	**Estimated Net Book Value (OCLD)**
364	Poles, Towers & Fixtures	1,752	$ 552,337	$ 460,653	**$ 91,684**
365	Overhead Conductors & Devices	2,297,751	$ 1,448,783	$ 1,287,806	**$ 160,976**
366	Underground Conduits	2,280	$ 2,597	$ 519	**$ 2,077**
367	Underground Conductors & Devices		$ -	$ -	**$ -**
368	Transformers	312	$ 457,610	$ 370,446	**$ 87,164**
369	Services	3,391	$ 304,073	$ 202,715	**$ 101,358**
370	Meters	505	$ 134,102	$ 89,400	**$ 44,701**
373	Street Lighting & Signal System	35	$ 8,906	$ 3,563	**$ 5,344**
	Total	**2,306,026**	**$ 2,908,407**	**$ 2,415,102**	**$ 493,304**

- With 1.5 x OCLD multiplier estimated negotiated sale is $740,000 for Peach Springs Distribution Assets
- Includes partial Supai Transmission Line (located in Peach Springs but not serving Peach Springs)

Forecast Costs: Annual Cost of Asset Purchase

- Principal + Interest = $50,000/year
- 20 year RUS backed loan (at 3% Municipal Interest Rate, maturing 2038)

- 30 year term reduces annual amount to $38,000/year
- 1% interest rate increase, annual payment increases by $5,000/year

Forecast Costs: Annual Capital Replacement

- Annualized cost: $155,000 per year
- Distribution System has 30 year average life – approximately 3% Replacement Cost New (RCN) value each year to replace system
- 2007 Feasibility: RCN of $3.8 million
- Inflated at 3% to 2017 – RCN estimate of $5.2 million

- Due to age of system at purchase, this could be higher in initial years
- If unspent in a year, keep as reserve for future years
- Savings potential for ratepayers with RUS Electric Program grants for replacement of assets

Forecast Costs: Annual Maintenance Costs

- Annual estimate $96,000 per year
- If MEC retains this role, could be higher (if charge premium or return for contracted service)
- Cost savings potential if locally sourced or combined with potential future GCW operation

Hualapai Only - Estimated Annual Maintenance Costs from MEC

	2016	2017
January		$ 15,723
February		$ 1,941
March		$ 17,991
April	$ 5,791	$ 5,829
May	$ 39,323	$ 6,740
June	$ 12,316	$ 7,312
July	$ 2,376	$ 2,359
August	$ 1,789	
September	$ 2,617	
October	$ 2,718	
November	$ 941	
December	$ 2,087	
Monthly Avg.	**$ 7,773**	**$ 8,271**

Forecast Costs: Annual Administrative & General

- Estimate of $150,000 per year
- From 2009 Feasibility Study, escalated for inflation
- Includes one full-time administrator and 3rd party contract labour for meter reading, billing, contract administration, power scheduling & customer service
- Savings potential if combined with existing HTUA staff or potential future GCW operation

Forecast Costs: Operating & Maintenance Comparison

- Comparable small, rural utilities in US have higher operating (including administrative and general) and maintenance costs on a per customer basis than Peach Springs forecast costs

	Peach Springs 2017 Update Feasibility	Kotzebue Electric Assn (Alaska) [2015]	Fishers Island Electric Corporation (New York) [2015]	Pleasant Hill Community Line (Iowa) [2015]
Ownership		Cooperative	Investor Owned	Cooperative
Revenues ($000s)	828	7,906	2,166	421
Sales (MWh)	8,073	19,889	6,032	4,497
Customers	359	1,268	759	116
Avg. Energy Rate (cents/kWh)	10.26	39.75	35.91	9.36
Operating & Maintenance Costs ($000s)	246	1,581	795	237
O & M per Customer ($)	**685**	**1,247**	**1,047**	**2,046**

Forecast Costs: Power Supply (Generation & Transmission)

- Forecast costs of 7.82 ¢/kWh (MEC's approved rate forecast based on 2015 test year); equals $631,700 at current energy usage
  - Actual Hualapai net energy costs were $548,671 in 2016; but this includes rate rider reductions
  - Reducing power supply forecast costs for rider (to 6.07 cents/kWh) has corresponding revenue reduction (i.e. negatively impacts cost shortfall on a percentage basis)
- Forecast costs do not include transmission charges from MEC as third party power supplier (currently charged through depreciation and finance expenses).
  - 2016 and 2017 actual Hualapai transmission costs relate to third party transmission charges MEC incurs from sourcing energy externally

Power Supply Costs from MEC

Annual		2016 - Jan-Dec		2017 - Jan-Aug
Energy	$	543,801.71	$	355,351.55
Transmission	$	4,869.62	$	17,855.22
Total	**$**	**548,671.33**	**$**	**373,206.77**

Preliminary Findings

- Acquisition of distribution assets from MEC results in a one time average <u>rate increase of approximately 30.7%</u> in order to break even in year 1.

NEXT STEPS

- Peach Springs Cost of Service
  - Awaiting revised data from MEC which could adjust asset replacement and acquisition estimates.
    - Don't expect material changes to conclusions
  - Consideration for included/excluded assets and acquisition negotiated price
  - Rate design considerations if warranted, such as approach to rate increases
- Further discussion on electricity reliability issues
- Review Grand Canyon West needs

5.0 HTUA Utility Costs Report DRAFT

Executive Summary

This report reviews the results of a cost of service analysis of the Peach Springs electrical services. It has been constructed to provide an estimate of the costs to deliver power service, on a stand-alone basis, assuming the assets were acquired by an independent utility (specifically HTUA).

The conclusions are subject to revision related to one outstanding data request to Mohave Electric Coop.

On the basis of the analysis, a best estimate cost of serving Peach Springs under an HTUA ownership model would require a rate increase on the order of 31%, or an annual subsidy in the range of $254,000/year. This is an increase from the 2007 and 2009 report forecasts, but in the same magnitude (22.2% and 26.0% respectively).

Options for addressing the subsidy, such as channeling profits from hydro power allocations or from Grand Canyon West power utility savings, have not been detailed. Any such allocation would only arise to the extent that these profits/savings are not already accounted for in other areas by the Hualapai, and as such these subsidy options come at an economic cost.

The analysis has been prepared on a cash basis, rather than a more traditional revenue requirement model. The differences are relatively small on an annual basis, but given HTUA has no track record or standing experience with routine borrowings, or ready capital markets access, ensuring rates cover cash requirements in a given year is the most prudent approach to estimating. The rate estimates provided below, even if bridged by a rate increase or an annual subsidy, still will not fully fund the HTUA in the event of atypical annual requirements – such as years of major rebuilds, cost outlays to deal with uninsured events like storm damage, major investments intended to improve service (e.g., smart meters or increased reliability initiatives), or other unexpected costs. Where these cash outlays can be planned for in advance, debt financing such as through the USDA may be available. However, where outlays occur without advance planning, e.g., storms, reserves would be required. The rate estimates in this paper do not include a provision for building reserves for these purposes – such additional cash requirements would require further discussion with HTUA regarding risk tolerance and what options may be used to cash flow this type of event.

Major items of uncertainty in the attached report relate to:

- Valuation, and the approach to valuation that may be imposed by MEC
- Delineation as to the assets to be acquired, including issues over service on the 70 mile line, which will require either HTUA to take on downstream service provision off Hualapai land, or will require some agreement with MEC to serve the 70 mile line area, but need to wheel power in some manner through a new HTUA system.

- Bulk power acquisition, which is assumed to come from MEC, delivered at the relevant substation (e.g., Nelson) and be available to HTUA at approximately the same net cost as it is delivered today as MEC customers. It is not clear what arrangements MEC would place on such service in the future. It is also possible that in time HTUA could secure an alternative source, such as from the WAPA service area, but this would only come at a net cost related to installing any required new facilities, plus costs of negotiating and implementing a new supply agreement – the unit cost savings on bulk power would need to be substantial to offset the cost implications of such arrangements.
- Reliability improvement, acquisition of distribution assets does not address reliability issues. For this cost estimate there are no costs included to improve reliability of delivered electricity. At present, it is not clear where investment would be required and how much would be required by HTUA, but could include the 69kV line between Nelson and Round Valley substations.

Peach Springs Distribution Asset - Valuation

From the 2007 Report, estimated acquisition cost of $210,000 was based on an average asset age of 50.4 years, a Replacement Cost New (RCN) estimate of $3.8 million and applicable depreciation of $3.2 million.

For the 2009 Update, this acquisition value was increased to $353,000 based on what was indicated to be substantial increases to the cost of materials, labor and especially transformer costs in the intervening years (not based on asset replacements, as the average age estimate was increased to 53 years in this study).

The 2007 Preliminary Assessment of Distribution System considered three estimates in its acquisition cost determination. Replacement costs were developed using cost estimating software on the inventory of the existing plant while the Original Cost at time of construction was calculated using the Handy Whitman utility cost index[1].

- Original Cost Less Depreciation (OCLD) – Calculating the Gross Book Value (cost of assets at the date installed) less an applicable deduction for depreciation. For calculating rates, often this is the cost included in revenue requirement (essentially Net Book Value).
- Replacement Cost New (RCN) – calculating the current cost of replacing the facilities in question with an identical facilities.
- Replacement Cost New Less Depreciation (RCNLD) - RCN less an applicable deduction for depreciation.

[1] 2007 Hualapai Utility Authority Feasibility Report, Appendix A: Preliminary Assessment of Distribution System, pages 2 - 3

In 2007, the average age of the facility was estimated based on a field survey. The estimate for poles, cross arms, conductors, etc. was 50.4 years. The average age of the street light system was 8 years. For the 2009 update report an updated field study was done which noted no observed physical appearance changes since 2007 on the Peach Springs assets. And conditions remained average to below average for a system of its age. The average age was increased to 53 years for poles, cross arms, conductors, etc. and remained at 8 years for the street light system in this report (it is not clear why this was not increased). The 2007 valuation is provided below.

Table 1: 2007 Peach Springs Distribution Asset Valuation

Code	Distribution Asset Category	Avg Age	Adj Age	Useful Life	RCN	RCNLD	OCLD
364	Poles, Towers & Fixtures	50.4	38	45	$ 1,436,520	223,459	$ 18,926
365	Overhead Conductors & Devices	50.4	40	45	$ 1,576,661	$ 175,185	$ 16,121
366	Underground Conduits	10	10	50	$ 13,782	$ 11,025	$ 7,917
367	Underground Conductors & Devices	10	10	35	$ 23,570	$ 16,836	$ 12,468
368	Transformers	50.4	34	42	$ 451,753	$ 86,048	$ 33,329
369	Services	20	20	30	$ 197,600	$ 65,867	$ 37,929
370	Meters	50.4	20	30	$ 61,664	$ 20,555	$ 2,014
373	Street Lighting & Signal System	8	8	20	$ 58,566	$ 35,139	$ 27,363
	Total				**$ 3,820,116**	**$ 634,114**	**$ 156,067**

The 2007 estimated RCN was very low (from MEC data, we are now informed that the distribution assets serving Peach Springs were largely installed in the 1950s and 1980s, and as of those dates cost $2.9 million[2]). Replacing this system at a cost on par with the cost to install in the 50s and 80s is unlikely unless there were large costs associated with site preparation. Implied in the 2007 Study valuation is accumulated depreciation (which is the difference between the RCN column and the RCNLD column), shown in the table below:

[2] Note: MEC is in the process of rechecking gross book value based on error in data. This amount does not include any changes pending. The original MEC values indicated $5.2 million, however in a later phone discussion one error was highlighted which reduced this value to $2.9 million. MEC is reviewing the remainder of the estimates and is expected to send an updated asset cost database once complete.

Table 2: 2007 Feasibility Study Asset Valuation

Code	Distribution Asset Category	RCN	RCNLD	Assumed Derpreciation (RCN - RCNLD)	% Depreciated
364	Poles, Towers & Fixtures	$ 1,436,520	223,459	1,213,061	84.44%
365	Overhead Conductors & Devices	$ 1,576,661	$ 175,185	$ 1,401,476	88.89%
366	Underground Conduits	$ 13,782	$ 11,025	$ 2,757	20.00%
367	Underground Conductors & Devices	$ 23,570	$ 16,836	$ 6,734	28.57%
368	Transformers	$ 451,753	$ 86,048	$ 365,705	80.95%
369	Services	$ 197,600	$ 65,867	$ 131,733	66.67%
370	Meters	$ 61,664	$ 20,555	$ 41,109	66.67%
373	Street Lighting & Signal System	$ 58,566	$ 35,139	$ 23,427	40.00%
	Total	**$ 3,820,116**	**$ 634,114**	**$ 3,186,002**	**83.40%**

Since the 2007 Study, we know the following additions/replacements have been made to the Peach Springs area asset base during 2012-2017 (data is not available about the cost of these projects, nor about projects completed between 2007 and 2011) shown in the Table below.

Some of the assets, as noted in the table, are not located on the Hualapai Reservation. Updated data from MEC to address this is forthcoming.

Table 3: MEC Provided Peach Springs System Additions/Improvements

COMPLETED SYSTEM IMPROVEMENTS	YEAR CONSTRUCTED	Assets not Located on Hualapai Reservation
PEACH SPRINGS SYSTEM	1947	
SUPAI 70 MILE LINE SYSTEM	1981	No
PRIMARY METERING - BIG BOQUILLAS TAP	2015	unknown
PRIMARY METERING - YOUTH CAMP	2016	
PRIMARY METERING - SOLAR GENERATION FACILITY	2013	No
PRIMARY METERING - SOUTH OF THE SOLAR GENERATION FACILITY	2014	
1 MILE SINGLE PHASE DISTRIBUTION, CIRCUIT #3 - *SERVING THE PUMP AT TANK WITH NELSON & PATRICIA CESSPOOCH*	2012	
3 PHASE VOLTAGE REGULATOR BANK, NORTH OF SOLAR FACILITY	2015	
3 UNDERGROUND RISERS, SERVING SUPAI VILLAGE	2015	No
PEACH SPRINGS SYSTEM & INDIAN 18 POLE INSPECTION	2015	
INSTALLATION OF 48 FAULT INDICATORS - INDIAN 18	2017	

Mohave Electric Cooperative (MEC) provided data to March 31, 2017 regarding the Peach Springs Asset Base Gross Book Value (i.e. cost of assets at installation date without any deductions since). It is shown comparatively to the 2007 Study RCN value (i.e. the estimated gross book value at that time):

Table 4: Peach Springs Distribution Gross Plant Provided by MEC, 2017 compared to 2007 Study[3]

		2007 Study	2017 MEC Data	
Code	**Distribution Asset Category**	**RCN**	**Quantity (#)**	**Gross Book Value ($)**
364	Poles, Towers & Fixtures	$ 1,436,520	1,752	$ 552,337
365	Overhead Conductors & Devices	$ 1,576,661	2,297,751	$ 1,448,783
366	Underground Conduits	$ 13,782	2,280	$ 2,597
367	Underground Conductors & Devices	$ 23,570		
368	Transformers	$ 451,753	312	$ 457,610
369	Services	$ 197,600	3,391	$ 304,073
370	Meters	$ 61,664	505	$ 134,102
373	Street Lighting & Signal System	$ 58,566	35	$ 8,906
	Total	**$ 3,820,116**	**2,306,026**	**$ 2,908,407**

MEC latest General Rate Application provides a breakdown of accumulated depreciation by asset category. Accumulated depreciation for the Distribution Plant for year ending 2015 is 28% of gross book value.[4] Comparatively, the 2007 Valuation Study approximated 83.4% of gross book value was depreciated specific for Peach Springs assets. Using both to provide a range out potential outcomes, the expected net book value would be between $493,304 and $2,068,008 shown below.

[3] Information provided by MEC sorted as follows: Account 364 consists of structures and assemblies (less area lights), 365 includes all OH and ACSR listed wires in conductors, less services wires and only $800k included in the '#2 ALUM TRIPLEX OH' asset category (waiting on MEC correction), 366 includes all UG wires (and implicitly account 367), 368 includes Transformers and 1PH Regulator Bank asset and Primary Metering assets (primary metering is made up of current and voltage transformers), 369 includes all Service Wires in the Conductors category, 370 includes Meters assets, 373 includes the 100W HPS Area Light asset listing within the assemblies category.

[4] MEC Rate Change Application 7.26.16, Notes to Financial Statements page 10 (pdf page 40 of 251) provides net book value (utility plant plus accumulated depreciation) of $74.64 million for 2015, page 11 (pdf page 41 of 251) provides distribution plant accumulated depreciation of $30.33 million for 2015. Adding the two, gross utility plant for distribution assets is $104.97 million. Dividing accumulated depreciation by gross utility plant gives you 28%.

Table 5: Estimated Net Book Value Calculation

			MEC Total Distribution Plant Acc. Depreciation Avg		2007 Valuation Acc. Depreciation Weighting		
Code	**Distribution Asset Category**	**Gross Book Value**	**Estimated Accumulated Depreciation (MEC Average)**	**Estimated Net Book Value (OCLD)**	**Gross Book Value ($)**	**Estimated Accumulated Depreciation (2007 Report %)**	**Estimated Net Book Value (OCLD)**
364	Poles, Towers & Fixtures	$ 552,337	$ 159,601	**$ 392,736**	$ 552,337	$ 460,653	**$ 91,684**
365	Overhead Conductors & Devices	$ 1,448,783	$ 418,633	**$ 1,030,149**	$ 1,448,783	$ 1,287,806	**$ 160,976**
366	Underground Conduits	$ 2,597	$ 750	**$ 1,846**	$ 2,597	$ 519	**$ 2,077**
367	Underground Conductors & Devices		$ -	**$ -**	$ -	$ -	**$ -**
368	Transformers	$ 457,610	$ 132,229	**$ 325,381**	$ 457,610	$ 370,446	**$ 87,164**
369	Services	$ 304,073	$ 87,863	**$ 216,210**	$ 304,073	$ 202,715	**$ 101,358**
370	Meters	$ 134,102	$ 38,749	**$ 95,352**	$ 134,102	$ 89,400	**$ 44,701**
373	Street Lighting & Signal System	$ 8,906	$ 2,573	**$ 6,333**	$ 8,906	$ 3,563	**$ 5,344**
	Total	**$ 2,908,407**	**$ 840,399**	**$ 2,068,008**	**$ 2,908,407**	**$ 2,415,102**	**$ 493,304**

Given that known system improvements and additions provided by MEC have been minimal (table provided above), it is more than likely that Peach Springs specific assets are older in age on average than MEC's collective system and therefore accumulated depreciation would be higher than the Distribution Plant average of 28%. Therefore, the net book value estimate is more likely closer to the low end of the range.

Note, the assetbase used currently includes the Supai transmission line, South Generation Facility and other asset additions/system improvements surrounding the Peach Springs vicinity that may not ultimately be included in the system purchase from MEC due to these assets not supporting Peach Springs electricity distribution.

Acquisition Cost

Using the estimated net book value estimate (which would approximate the OCLD figure defined above) of $493,304 an approximate purchase price for the assets would likely include a multiplier (i.e. MEC would require asset value plus some level of return). The 2007 Valuation Report uses a 1.4 to 1.6 times OCLD range as the most common range for negotiated sales.[5] Using the midpoint of 1.5 times OCLD results in an asset purchase price of approximately $740,000.

Acquisition Cost - Annualized (Principal & Interest)

Assuming a loan is secured through the Rural Utilities Services (RUS), current Municipal interest rates offered through the RUS for a 20 year loan (terms ending in 2038 or later) are 3.00%, although these rates are subject to approval and change daily.[6] The annual Principal and

[5] 2007 Hualapai Utility Authority Feasibility Report, Appendix A: Preliminary Assessment of Distribution System, page 5

[6] Municipal Interest Rates for the 4th Quarter of CY 2017, as of November 8, 2017. Available online: https://www.rd.usda.gov/programs-services/services/rural-utilities-loan-interest-rates

Interest costs of this would be approximately $50,000 per year. The annual breakdown is provided in the table below.

Table 6: Annualized Principal and Interest Repayment of a 20-year loan with the RUS for $740,000 at 3% Annual Interest

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Principal Repayment	27,538	28,364	29,215	30,092	30,994	31,924	32,882	33,868	34,884	35,931
Interest Repayment	22,199	21,373	20,522	19,645	18,742	17,813	16,855	15,868	14,852	13,806
Total	**49,737**	**49,737**	**49,737**	**49,737**	**49,737**	**49,737**	**49,737**	**49,737**	**49,737**	**49,737**
Year	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
Principal Repayment	37,009	38,119	39,263	40,440	41,654	42,903	44,190	45,516	46,882	48,288
Interest Repayment	12,728	11,618	10,474	9,296	8,083	6,833	5,546	4,221	2,855	1,449
Total	**49,737**	**49,737**	**49,737**	**49,737**	**49,737**	**49,737**	**49,737**	**49,737**	**49,737**	**49,737**

Each interest rate increase of 1% represents approximately $5,000 in additional annual repayment costs (e.g. if the annual interest rate is 5%, the annual principal and interest costs are $60,000).

Capital Reinvestment/Replacement Annualized

As the system being purchased is quite aged (average age of 54 years in the 2009 Updated Study, with minimal system improvements/replacements in the intervening years) it is anticipated that the system maintenance and replacement costs could be quite high in the early years of operation (e.g., first 10 years).

On average it is assumed that a distribution system will need replacement at a rate of 3% per year (MEC's distribution plant has an average service life of around 30 or more years depending on the asset class, and depreciates its distribution plant under the straight-line composite basis of 3% per year[7] consistent with the Uniform System of Accounts as prescribed by the Rural Utilities Service (RUS)[8]). As an example, MEC's current average service lives for applicable Distribution Plant assets is shown in the table below.

[7] MEC Rate Change Application 7.26.16, Notes to Financial Statements page 11 (pdf page 41 of 251)
[8] MEC Rate Change Application 7.26.16, Notes to Financial Statements page 8 (pdf page 38 of 251)

Table 7: Distribution Plant Average Service Lives[9]

Distribution Plant		Depreciation Rate	*Calculated Average Service Life*
364.00	Poles, Towers & Fixtures	3.00%	*33*
365.00	Overhead Conductors & Devices	2.30%	*43*
366.00	Underground Conduits	1.80%	*56*
367.00	Underground Conductors & Devices	2.40%	*42*
368.00	Transformers	2.60%	*38*
369.00	Services	3.10%	*32*
370.00	CTs, PTs, Etc. & Meters	5.54%	*18*
370.00	Bases	10.00%	*10*
370.00	Other AMI Equipment	12.94%	*8*
373.00	Street Lighting & Signal System	3.80%	*26*
	Average		*30*

For this calculation the Gross Book Value (i.e. OCLD) will not be sufficient as the cost to install the assets in the past will not equate to the cost today. Using the 2007 RCN value, inflated at 3% per year for 10 years the 2017 RCN is approximately $5.15 million. It should be noted that the RCN used in the 2007 study is potentially very low. The distribution assets serving Peach Springs were largely installed in the 1950s and 1980s; and at that time cost $2.9 million[10]. Replacing this system today at an amount less than double the cost to install in the 50s and 80s is unlikely (unless there were large costs in the original investment associated with items that do not need to be repeated, such as site preparation or land/ROW acquisition).

However, as an estimate, the annual replacement cost of 3% a year would equate to approximately $155,000 per year. As the Peach Springs system may be approaching 60 years average age (double the average service life of the system) it is likely this amount could be higher in the initial serviceable years.

Potential cost savings exist in the form of RUS Electric Program grants, loans and loan guarantees for construction of electric distribution, transmission, and generation facilities (including system improvements and replacement) as well as demand side management, energy efficiency and conservation programs and on-grid and off-grid renewable energy systems.[11]

[9] MEC Rate Change Application 7.26.16, Schedule C-2.12, (pdf pages 112 and 113 of 251)
[10] Note: MEC is in the process of rechecking gross book value based on error in data. This amount does not include any changes pending.
[11] United States Department of Agriculture Rural Development Electric Programs website. Available online: https://www.rd.usda.gov/programs-services/all-programs/electric-programs

Operating, Maintenance, Administrative, & General Costs

Annual maintenance costs for the last nine months of 2016 and for the first eight months of 2017 were provided by MEC and vary considerably month to month. On average between the data provided for 2016 and 2017 monthly maintenance is estimated at $8,000. On an annualized basis this is $96,000 per year.

Table 8: Peach Springs Monthly Maintenance Costs per MEC

	2016	2017
January		$ 15,723
February		$ 1,941
March		$ 17,991
April	$ 5,791	$ 5,829
May	$ 39,323	$ 6,740
June	$ 12,316	$ 7,312
July	$ 2,376	$ 2,359
August	$ 1,789	
September	$ 2,617	
October	$ 2,718	
November	$ 941	
December	$ 2,087	
Monthly Avg.	**$ 7,773**	**$ 8,271**

Depending on agreements made, if HTUA retains MEC to continue maintenance of the system (if this is possible) it is likely that the costs charged will be higher and incorporate a return component. In the long-term, as the system is slowly replaced, it is expected these costs would slowly decrease on a real basis (i.e. not including the inflation).

Administrative & General costs were contemplated in the 2007 and 2009 feasibility studies. Annual forecast costs for the in house administrative services (assume this includes salaries & wages, benefits and system costs) was $113,974 in the 2007 Feasibility and $127,400 for the 2010 year in the 2009 update. Adjusting for inflation, the annual Administrative and General costs from these earlier reports would be approximately $150,000 per year.[12]

Comparing to other rural utilities of a similar size, the combined forecast operating and maintenance costs for Peach Springs are far lower on per customer basis as shown in the table below.

[12] Assuming 2.5% inflation for 7 years to the 2010 forecast of $127,400 is approximately $150k.

Table 9: Operating, Administrative & Maintenance Cost Comparison to Similar Sized Rural Utilities

	Peach Springs 2017 Update Feasibility	Kotzebue Electric Assn (Alaska) [2015]	Fishers Island Electric Corporation (New York) [2015]	Pleasant Hill Community Line (Iowa) [2015]
Ownership		Cooperative	Investor Owned	Cooperative
Revenues ($000s)	828	7,906	2,166	421
Sales (MWh)	8,073	19,889	6,032	4,497
Customers	359	1,268	759	116
Avg. Energy Rate (cents/kWh)	10.26	39.75	35.91	9.36
Operating & Maintenance Costs ($000s)	246	1,581	795	237
O & M per Customer ($)	**685**	**1,247**	**1,047**	**2,046**

Power Supply Costs

MEC provided 2016 and partial 2017 power supply costs for the Hualapai Tribe as provided in the Table below. Monthly averages are also provided to compare how 2017 is tracking compared to 2016. In general, transmission costs are higher for 2017 than 2016 while energy costs are slightly reduced. The reason for the cost fluctuation is not clear but likely involves as required third party transmission purchases by MEC that are passed through to the Hualapai Reservation.

Table 10: 2016 and Partial 2017 Power Supply Costs from MEC

Annual	2016 - Jan-Dec	2017 - Jan-Aug
Energy	$ 543,801.71	$ 355,351.55
Transmission	$ 4,869.62	$ 17,855.22
Total	**$ 548,671.33**	**$ 373,206.77**

Monthly Average	2016	2017
Energy	$ 45,316.81	$ 44,418.94
Transmission	$ 405.80	$ 2,231.90
Total Average	**$ 45,722.61**	**$ 46,650.85**

For forecast revenue requirement purposes, the 2016 values are used to estimate future costs (considering energy costs have not been increasing substantially). It is not apparent why transmission costs would fluctuate so severely year over year.

However, the power supply costs provided include the reduced revenues from the negative rate rider included in rates for 2016 and 2017 by MEC. Additionally, transmission costs only include the external transmission charges to MEC from external sources. It is not expected that HTUA would receive cost reduction benefits when no longer a member of the cooperative.

If the HTUA uses MEC as a third party to purchase energy or instead purchases directly from Arizona Electric Power Cooperative Inc. (AEPCO), Western or APS, power supply costs will likely be higher due to increased transmission charges (charged by MEC or other third parties to transfer energy that are currently included in rates paid to MEC). On a forecast basis, the 2015 MEC test year power supply costs are used on a cents per kilowatt hour (kWh) basis to approximate the charges HTUA could expect from MEC as a third party power provider. This does not include additional transmission charges that MEC may charge, which could further increase power supply costs.

The total generation power supply forecast based on 2016 Peach Springs energy usage is $631,693 at MEC approved power supply costs[13] or $490,414 if factoring in the reduction rider in place for 2017[14].

Total Forecast Annual Utility Operating Costs

Total projected annual costs are provided in the tables below with the 2007 and 2009 feasibility comparisons. Table 11 estimates generation supply costs at the rate approved in the 2016 Rate Change Application. Total projected costs are estimated to be slightly over $1 million for 2019 as seen in Table 11.

Table 12 includes a reduction to the cost of generation power supply on a cents/kWh basis as consistent with prices paid today due to a monthly reduction rider in place of 1.75 cents/kWh. At this current rate of generation in place for 2017 (without inclusion of a transmission charge for power delivery) estimated annual costs are $941,151 in 2019.

In the 2007 and 2009 Feasibility studies, power supply costs represented approximately 65% and 75% respectively for total annual costs in the 2010 forecast year. Approximately one quarter of this was transmission related power supply in both cases, with the remainder representing generation costs. For the 2019 forecast test year, transmission power supply costs are not included, but generation related power supply costs have increased slightly as a percentage of total annual costs (for the table without inclusion of the reduction rider). Presumably this includes a portion of third party transmission costs, which were minimal in cost for 2016 (see above table). Nevertheless, the total forecast annual operating costs likely underestimates the cost associated with transmission delivery charges.

[13] Based on 7.825 cents/kWh 2015 test year generation power supply costs of $51.4 million divided by MEC total forecast energy usage of 657.1 GWh from MEC's 2016 Rate Change Application for test year ending December 31, 2015, Attachment 4, MEC Financial Section of Rate and Cost of Service Study, Schedule C-1.0 Adjusted Test Year Income Statement for Year ending 12/31/2015 (pdf page 84 - of 251)

[14] Estimated at 6.07 cents/kWh, based on previous estimate of 7.825 cents/kWh less the negative 1.75 cents/kWh monthly rate rider (PCA) in place as of December, 2015 (and currently in place for rates in 2017).

Table 11: Forecast Annual Revenue Requirement Based on Updated Asset Cost Data from MEC ($ Dollars) – 2016 MEC Approved Power Supply Costs[15]

	2019 Test Year		2010 Forecast Year			
Peach Springs Annual Revenue Requirement	**MEC Adjusted Test Year**	**MEC cents/ kWh**	**2007 Study**	**2007 cents/ kWh**	**2009 Update**	**2009 cents/ kWh**
Power Supply (Generation)	$ 631,693	7.82	$ 337,509	5.35	$ 582,314	6.08
Power Supply (Transmission)	$ -	-	$ 119,916	1.90	$ 191,998	2.01
OM&C - Distribution Related	$ 96,000	1.19	$ 50,206	0.80	$ 105,554	1.10
OM&C - Customer Related	$ -	-	$ 11,569	0.18		-
Administrative & General	$ 150,000	1.86	$ 113,974	1.81	$ 127,400	1.33
Asset Replacement	$ 155,000	1.92				
Depreciation/Debt Service - Principal	$ 27,538	0.34	$ 8,290	0.13		-
Finance Expense/Debt Service - Interest	$ 22,199	0.27	$ 62,560	0.99	$ 39,623	0.41
Other Expenses (tax)	$ -	-		-		-
Reserves		-	$ 5,306	0.08	$ 5,000	0.05
Total Projected Costs	**$ 1,082,430**	**13.41**	**$ 709,330**	**11.25**	**$ 1,051,889**	**10.99**

Table 12: Forecast Annual Revenue Requirement Based on Updated Asset Cost Data from MEC ($ Dollars) – Adjusted for Power Supply Interim Rate Reductions

	2019 Test Year		2010 Forecast Year			
Peach Springs Annual Revenue Requirement	**MEC Adjusted Test Year**	**MEC cents/ kWh**	**2007 Study**	**2007 cents/ kWh**	**2009 Update**	**2009 cents/ kWh**
Power Supply (Generation)	$ 490,414	6.07	$ 337,509	5.35	$ 582,314	6.08
Power Supply (Transmission)	$ -	-	$ 119,916	1.90	$ 191,998	2.01
OM&C - Distribution Related	$ 96,000	1.19	$ 50,206	0.80	$ 105,554	1.10
OM&C - Customer Related	$ -	-	$ 11,569	0.18		-
Administrative & General	$ 150,000	1.86	$ 113,974	1.81	$ 127,400	1.33
Asset Replacement	$ 155,000	1.92				
Depreciation/Debt Service - Principal	$ 27,538	0.34	$ 8,290	0.13		-
Finance Expense/Debt Service - Interest	$ 22,199	0.27	$ 62,560	0.99	$ 39,623	0.41
Other Expenses (tax)	$ -	-		-		-
Reserves		-	$ 5,306	0.08	$ 5,000	0.05
Total Projected Costs	**$ 941,151**	**11.66**	**$ 709,330**	**11.25**	**$ 1,051,889**	**10.99**

The differential in generation power supply costs between the above two tables is caused by inclusion of the 1.75 cent/kWh monthly rider reduction for 2017. This cost reduction is offset by a corresponding decrease to forecast revenues, as seen in the table below.

[15] 2019 cents/kWh calculation uses updated 2016 actual load data shown in the table below. For 2007 and 2009 feasibility the asset replacement costs were bundled with the principal * interest costs.

Peach Springs Revenue to Cost Comparison

MEC provided updated load data for Peach Springs in fall 2017. Previous load data used was missing a few new accounts that had been added. The result of the updated load data is an increase in annual energy usage, for 2016 total was 8.07 million kWh. This is shown in Table 13 (without rider) and Table 14 (with rate rider) below. At MEC approved 2017 rates (with riders) this would provide $687,172 in annual revenues. Without the rate rider factored in (i.e. at approved power supply costs in MEC's 2016 Rate Change Application) revenues are forecast at $828,452. The resulting revenue to revenue requirement shortfall is provided in the table below.

Table 13: Estimated Revenue to Cost Comparison at Existing MEC Rates (with and without rate rider reduction to revenue and power supply cost), Updated Load Forecast and Updated Asset Valuation Data

	Revenue		Costs		*Difference*		Rate Increase Required
	$	¢/kWh	$	¢/kWh	***$***	***¢/kWh***	
2017 Estimate (without power supply rate reduction rider)	**828,452**	**10.26**	**1,082,430**	**13.41**	***-253,978***	***-3.15***	**30.7%**
2017 Estimate (with power supply rate reduction rider)	**687,172**	**8.51**	**941,151**	**11.66**	***-253,978***	***-3.15***	**37.0%**
2007 Feasibility (2010 forecast year)	580,403	9.21	709,330	11.25	*-128,927*	*-2.05*	22.2%
2009 Feasibility (2010 forecast year)	834,638	8.72	1,051,889	10.99	*-217,251*	*-2.27*	26.0%

Based on these estimates, the acquisition of distribution assets from MEC would result in an average rate increase of 30.7% in order to break even in the initial year. If adjusting for the current cost of generation, a rate increase of 37% from current electricity bills would be required.

Table 14: Peach Springs Forecast Load, Revenue and Average Rates Comparison 2007 Feasibility, 2009 Update and MEC Actuals – Updated with Adjusted Load from MEC[1]

Load	2010 Forecast Year		Peach Springs Actual 2011	Peach Springs Actual 2012	Peach Springs Actual 2013	Peach Springs Actual 2014	Peach Springs Actual 2015	Peach Springs Actual 2016	2016
Rate	**2007 Feasibility (2010 forecast year)**	**2009 Feasibility (2010 forecast year)**	**MEC Average Rate (1991 approved rate)**	**MEC Average Rate (2012 approved rate)**	**MEC Average Rate (2012 approved rate)**	**MEC Average Rate (2012 approved rate)**	**MEC Average Rate (2012 approved rate)**	**MEC Average Rate (2012 approved rate)**	**MEC Average Rate (2017 approved rate)**
Residential									
kWh	2,933,587	2,995,894	2,953,423	2,899,603	3,048,626	2,859,231	2,985,476	3,031,212	3,031,212
revenue	$ 286,939	$ 294,576	$ 286,555	$ 353,882	$ 368,487	$ 350,105	$ 362,083	$ 366,476	$ 373,774
Average Consumers	377	362	358	358	360	360	359	358	358
Avg. Energy Rate (cents/kWh)	**9.78**	**9.83**	**9.70**	**12.20**	**12.09**	**12.24**	**12.13**	**12.09**	**12.33**
Small Commercial - Energy									
kWh	2,352,795	2,369,972	849,158	922,709	925,949	915,793	1,011,152	970,178	970,178
revenue	$ 219,514	$ 229,736	$ 79,971	$ 115,719	$ 117,172	$ 116,122	$ 127,203	$ 123,957	$ 126,573
Average Consumers	73	82	74	79	83	83	88	92	92
Avg. Energy Rate (cents/kWh)	**9.33**	**9.69**	**9.42**	**12.54**	**12.65**	**12.68**	**12.58**	**12.78**	**13.05**
Small Commercial - Demand									
kWh			1,522,180	1,627,182	1,634,968	1,643,650	2,090,987	2,058,822	2,058,822
revenue			$ 91,011	$ 132,451	$ 134,231	$ 135,640	$ 170,129	$ 168,087	$ 171,830
Average Load Factor			33.7%	35.5%	34.5%	33.6%	35.7%	35.4%	35.4%
Average Consumers			17	18	21	22	23	24	24
Avg. Energy Rate (cents/kWh)			**5.98**	**8.14**	**8.21**	**8.25**	**8.14**	**8.16**	**8.35**
Small Commercial - Total									
kWh	2,352,795	2,369,972	2,371,338	2,549,891	2,560,917	2,559,443	3,102,139	3,029,000	3,029,000
revenue	219,514	229,736	170,982	248,170	251,403	251,762	297,332	292,044	298,403
Average Load Factor	0.0%	0.0%	33.7%	35.5%	34.5%	33.6%	35.7%	35.4%	35.4%
Average Consumers	73	82	91	97	104	105	111	116	116
Avg. Energy Rate (cents/kWh)	**9.33**	**9.69**	**7.21**	**9.73**	**9.82**	**9.84**	**9.58**	**9.64**	**9.85**
Large Commercial									
kWh	1016712	4,205,027	2,183,000	2,202,040	2,127,800	1,937,880	2,146,120	2,012,920	2,012,920
revenue	$ 73,950	$ 310,326	$ 107,616	$ 167,423	$ 162,329	$ 148,597	$ 163,939	$ 153,827	$ 156,275
Load Factor	50.0%	50.0%	51.1%	53.9%	51.2%	51.1%	48.6%	53.3%	53.3%
Average Consumers	2	5	4	4	4	4	4	4	4
Avg. Energy Rate (cents/kWh)	**7.27**	**7.38**	**4.93**	**7.60**	**7.63**	**7.67**	**7.64**	**7.64**	**7.76**
Total									
kWh	**6,303,094**	**9,570,893**	**7,507,761**	**7,651,534**	**7,737,343**	**7,356,554**	**8,233,735**	**8,073,132**	**8,073,132**
revenue	**580,403**	**834,638**	**565,153**	**769,475**	**782,218**	**750,465**	**823,354**	**812,347**	**828,452**
Average Consumers	**378**	**363**	**359**	**359**	**361**	**361**	**360**	**359**	**359**
Avg. Energy Rate (cents/kWh)	**9.21**	**8.72**	**7.53**	**10.06**	**10.11**	**10.20**	**10.00**	**10.06**	**10.26**

[1] MEC average energy rate based on rates approved in Arizona Corporation Commission Decision No. 75931, dated January 13, 2017. Actual Peach Springs load and energy is used for kWh calculation for each year 2011 to 2016; as provided by MEC. Residential energy rate for MEC switched to a block structure for the 2012 rate. For simplicity, it is assumed 60% of load for residential is in the first block, 30% in second block and 10% in third block based on a cursory review of average annual use for this class in the 2013 year.

Table 15: Peach Springs Forecast Load, Revenue and Average Rates Comparison 2007 Feasibility, 2009 Update and MEC Actuals (with rate riders) – Updated with Adjusted Load from MEC[2]

Load	2010 Forecast Year		Peach Springs Actual 2011	Peach Springs Actual 2012	Peach Springs Actual 2013	Peach Springs Actual 2014	Peach Springs Actual 2015	Peach Springs Actual 2016	2016
Rate	**2007 Feasibility (2010 forecast year)**	**2009 Feasibility (2010 forecast year)**	**MEC Average Rate (1991 approved rate w 2011 rider)**	**MEC Average Rate (2012 approved rate w 2012 rider)**	**MEC Average Rate (2012 approved rate w 2013 rider)**	**MEC Average Rate (2012 approved rate w 2014 rider)**	**MEC Average Rate (2012 approved rate w 2015 rider)**	**MEC Average Rate (2012 approved rate w 2016 rider)**	**MEC Average Rate (2017 approved rate w 2017 rider)**
Residential									
kWh	2,933,587	2,995,894	2,953,423	2,899,603	3,048,626	2,859,231	2,985,476	3,031,212	3,031,212
revenue	$ 286,939	$ 294,576	$ 343,285	$ 381,065	$ 368,753	$ 334,391	$ 323,159	$ 313,694	$ 320,728
Average Consumers	377	362	358	358	360	360	359	358	358
Avg. Energy Rate (¢/kWh)	**9.78**	**9.83**	**11.62**	**13.14**	**12.10**	**11.70**	**10.82**	**10.35**	**10.58**
Small Commercial - Energy									
kWh	2,352,795	2,369,972	849,158	922,709	925,949	915,793	1,011,152	970,178	970,178
revenue	$ 219,514	$ 229,736	$ 96,282	$ 124,369	$ 117,172	$ 111,009	$ 113,931	$ 106,979	$ 109,595
Average Consumers	73	82	74	79	83	83	88	92	92
Avg. Energy Rate (¢/kWh)	**9.33**	**9.69**	**11.34**	**13.48**	**12.65**	**12.12**	**11.27**	**11.03**	**11.30**
Small Commercial - Demand									
kWh			1,522,180	1,627,182	1,634,968	1,643,650	2,090,987	2,058,822	2,058,822
revenue			$ 120,249	$ 147,706	$ 134,231	$ 126,463	$ 142,685	$ 132,058	$ 135,800
Average Load Factor			33.7%	35.5%	34.5%	33.6%	35.7%	35.4%	35.4%
Average Consumers			17	18	21	22	23	24	24
Avg. Energy Rate (¢/kWh)			**7.90**	**9.08**	**8.21**	**7.69**	**6.82**	**6.41**	**6.60**
Small Commercial - Total									
kWh	2,352,795	2,369,972	2,371,338	2,549,891	2,560,917	2,559,443	3,102,139	3,029,000	3,029,000
revenue	219,514	229,736	216,532	272,075	251,403	237,472	256,616	239,037	245,395
Average Load Factor	0.0%	0.0%	33.7%	35.5%	34.5%	33.6%	35.7%	35.4%	35.4%
Average Consumers	73	82	91	97	104	105	111	116	116
Avg. Energy Rate (¢/kWh)	**9.33**	**9.69**	**9.13**	**10.67**	**9.82**	**9.28**	**8.27**	**7.89**	**8.10**
Large Commercial									
kWh	1016712	4,205,027	2,183,000	2,202,040	2,127,800	1,937,880	2,146,120	2,012,920	2,012,920
revenue	$ 73,950	$ 310,326	$ 149,547	$ 188,068	$ 162,329	$ 137,777	$ 135,771	$ 118,601	$ 121,049
Load Factor	50.0%	50.0%	51.1%	53.9%	51.2%	51.1%	48.6%	53.3%	53.3%
Average Consumers	2	5	4	4	4	4	4	4	4
Avg. Energy Rate (¢/kWh)	**7.27**	**7.38**	**6.85**	**8.54**	**7.63**	**7.11**	**6.33**	**5.89**	**6.01**
Total									
kWh	**6,303,094**	**9,570,893**	**7,507,761**	**7,651,534**	**7,737,343**	**7,356,554**	**8,233,735**	**8,073,132**	**8,073,132**
revenue	**580,403**	**834,638**	**709,364**	**841,208**	**782,484**	**709,640**	**715,546**	**671,331**	**687,172**
Average Consumers	**452**	**449**	**453**	**459**	**468**	**470**	**474**	**478**	**478**
Avg. Energy Rate (¢/kWh)	**9.21**	**8.72**	**9.45**	**10.99**	**10.11**	**9.65**	**8.69**	**8.32**	**8.51**

[2] MEC average energy rate based on rates approved in Arizona Corporation Commission Decision No. 75931, dated January 13, 2017. Actual Peach Springs load and energy is used for kWh calculation for each year 2011 to 2016; as provided by MEC. Residential energy rate for MEC switched to a block structure for the 2012 rate. For simplicity, it is assumed 60% of load for residential is in the first block, 30% in second block and 10% in third block based on a cursory review of average annual use for this class in the 2013 year.

6.0 Updated HTUA Utility Costs Report DRAFT

PROJECTED COST OF SERVICE FOR POTENTIAL HUALAPAI TRIBAL UTILITY AUTHORITY: Peach Springs Distribution Asset Acquisition

Prepared By:
InterGroup Consultants Ltd.

DRAFT
December 11, 2017

Executive Summary

This report reviews the results of a cost of service analysis of the Peach Springs electrical services. It has been constructed to provide an estimate of the costs to deliver power service, on a stand-alone basis, assuming the assets were acquired by an independent utility (specifically HTUA).

On the basis of the analysis, a best estimate cost of serving Peach Springs under an HTUA ownership model would require a rate increase on the order of 29%, or an annual subsidy in the range of $237,000/year. This is an increase from the 2007 and 2009 report forecasts, but in the same magnitude (22.2% and 26.0% respectively) (see Table 16).

Options for addressing the subsidy, such as channeling profits from hydro power allocations or from Grand Canyon West power utility savings, have not been detailed. Any such allocation would only arise to the extent that these profits/savings are not already accounted for in other areas by the Hualapai, and as such these subsidy options come at an economic cost.

The analysis has been prepared on a cash basis, rather than a more traditional revenue requirement model. The differences are relatively small on an annual basis, but given HTUA has no track record or standing experience with routine borrowings, or ready capital markets access, ensuring rates cover cash requirements in a given year is the most prudent approach to estimating. The rate estimates provided below, even if bridged by a rate increase or an annual subsidy, still will not fully fund the HTUA in the event of atypical annual requirements – such as years of major rebuilds, cost outlays to deal with uninsured events like storm damage, major investments intended to improve service (e.g., smart meters or increased reliability initiatives), or other unexpected costs. Where these cash outlays can be planned for in advance, debt financing such as through the USDA/RUS may be available. However, where outlays occur without advance planning (e.g., storms), reserves would be required. The rate estimates in this paper do not include a provision for building reserves for these purposes – such additional cash requirements would require further discussion with HTUA regarding risk tolerance and what options may be used to cash flow this type of event.

Major items of uncertainty in the attached report relate to:

- Valuation, and the approach to valuation that may be imposed by Mohave Electric Cooperative (MEC)
- Delineation as to the assets to be acquired, including issues over service on the 70 mile line, which will require either HTUA to take on downstream service provision off Hualapai land, or will require some agreement with MEC to serve the 70 mile line area, but need to wheel power in some manner through a new HTUA system.
- Bulk power acquisition, which is assumed to come from MEC (or at least through MEC transmission assets), delivered at the relevant substation (e.g., Nelson or Kingman) and be available to HTUA at approximately the same net cost as it is delivered today as MEC

customers. It is not clear what arrangements MEC would place on such service in the future. It is also possible that in time HTUA could secure an alternative source, such as from the WAPA service area, but this would only come at a net cost related to installing any required new facilities, plus costs of negotiating and implementing a new supply agreement – the unit cost savings on bulk power would need to be substantial to offset the cost implications of such arrangements.

- Reliability improvements, and issues with reliability are not addressed by the acquisition of distribution assets from MEC. For this cost estimate there are no costs included to improve reliability of delivered electricity. At present, it is not clear where investment would be required and how much would be required by HTUA, but could include the 69kV line between Nelson and Round Valley substations.

Peach Springs Distribution Asset - Valuation

From the 2007 Report, an estimated acquisition cost of $210,000 was based on an average asset age of 50.4 years, a Replacement Cost New (RCN) estimate of $3.8 million and applicable depreciation of $3.2 million (i.e. Replacement Cost New Less Depreciation was estimated at $0.6 million), as shown in Table 1.

For the 2009 Update, this acquisition value was increased to $353,000 based on what was indicated to be substantial increases to the cost of materials, labor and especially transformer costs in the intervening years (not based on asset replacements, as the average age estimate was increased to 53 years in this study).

The 2007 Preliminary Assessment of Distribution System considered three estimates in its acquisition cost determination. Replacement costs were developed using cost estimating software on the inventory of the existing plant while the Original Cost at time of construction was calculated using the Handy Whitman utility cost index[1].

- Original Cost Less Depreciation (OCLD) – Calculating the Gross Book Value (cost of assets at the date installed) less an applicable deduction for depreciation. For calculating rates, often this is the cost included in revenue requirement (essentially Net Book Value).
- Replacement Cost New (RCN) – calculating the current cost of replacing the facilities in question with an identical facilities.
- Replacement Cost New Less Depreciation (RCNLD) - RCN less an applicable deduction for depreciation.

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[1] 2007 Hualapai Utility Authority Feasibility Report, Appendix A: Preliminary Assessment of Distribution System, pages 2 - 3

In 2007, the average age of the facility was estimated based on a field survey. The estimate for poles, cross arms, conductors, etc. was 50.4 years. The average age of the street light system was 8 years. For the 2009 update report an updated field study was done which noted no observed physical appearance changes since 2007 on the Peach Springs assets. And conditions remained average to below average for a system of its age. The average age was increased to 53 years for poles, cross arms, conductors, etc. and remained at 8 years for the street light system in this report (it is not clear why this was not increased). The 2007 valuation is provided below.

Table 1: 2007 Peach Springs Distribution Asset Valuation

Code	Distribution Asset Category	Avg Age	Adj Age	Useful Life	RCN	RCNLD	OCLD
364	Poles, Towers & Fixtures	50.4	38	45	$ 1,436,520	223,459	$ 18,926
365	Overhead Conductors & Devices	50.4	40	45	$ 1,576,661	$ 175,185	$ 16,121
366	Underground Conduits	10	10	50	$ 13,782	$ 11,025	$ 7,917
367	Underground Conductors & Devices	10	10	35	$ 23,570	$ 16,836	$ 12,468
368	Transformers	50.4	34	42	$ 451,753	$ 86,048	$ 33,329
369	Services	20	20	30	$ 197,600	$ 65,867	$ 37,929
370	Meters	50.4	20	30	$ 61,664	$ 20,555	$ 2,014
373	Street Lighting & Signal System	8	8	20	$ 58,566	$ 35,139	$ 27,363
	Total				**$ 3,820,116**	**$ 634,114**	**$ 156,067**

The 2007 estimated RCN was very low (from MEC data, we are now informed that the distribution assets serving Peach Springs were largely installed in the 1950s and 1980s, and as of those dates cost $1.9 million). Replacing this system at only two times the cost to install in the 50s and 80s is unlikely unless there were large costs associated with site preparation. Implied in the 2007 Study valuation is accumulated depreciation (which is the difference between the RCN column and the RCNLD column), shown in the table below:

Table 2: 2007 Feasibility Study Asset Valuation

Code	Distribution Asset Category	RCN	RCNLD	Assumed Depreciation (RCN - RCNLD)	% Depreciated
364	Poles, Towers & Fixtures	$ 1,436,520	223,459	1,213,061	84%
365	Overhead Conductors & Devices	$ 1,576,661	$ 175,185	$ 1,401,476	89%
366	Underground Conduits	$ 13,782	$ 11,025	$ 2,757	20%
367	Underground Conductors & Devices	$ 23,570	$ 16,836	$ 6,734	29%
368	Transformers	$ 451,753	$ 86,048	$ 365,705	81%
369	Services	$ 197,600	$ 65,867	$ 131,733	67%
370	Meters	$ 61,664	$ 20,555	$ 41,109	67%
373	Street Lighting & Signal System	$ 58,566	$ 35,139	$ 23,427	40%
	Total	**$ 3,820,116**	**$ 634,114**	**$ 3,186,002**	**83.40%**

Since the 2007 Study, we know the following additions/replacements have been made to the Peach Springs area asset base during 2012-2017 (data is not available about the cost of these projects, nor about projects completed between 2007 and 2011) shown in the Table below.

Some of the assets, as noted in the table, are not located on the Hualapai Reservation. This includes, for example the primary metering for the solar generation facility, shown in the Table below. Note, it appears very little investment has occurred in replacements, notwithstanding the average age of the distribution study noted in the 2007 and 2009 feasibility studies.

Table 3: MEC Provided Peach Springs System Additions/Improvements

COMPLETED SYSTEM IMPROVEMENTS	YEAR CONSTRUCTED*	Assets Serving Hualapai Reservation
PEACH SPRINGS SYSTEM	1947	Yes
PRIMARY METERING - BIG BOQUILLAS TAP	2015	Unknown
PRIMARY METERING - YOUTH CAMP	2016	
PRIMARY METERING - SOLAR GENERATION FACILITY	2013	No
PRIMARY METERING - SOUTH OF THE SOLAR GENERATION FACILITY	2014	
1 MILE SINGLE PHASE DISTRIBUTION, CIRCUIT #3 - *SERVING THE PUMP AT TANK WITH NELSON & PATRICIA CESSPOOCH*	2012	
3 PHASE VOLTAGE REGULATOR BANK, NORTH OF SOLAR FACILITY	2015	
3 UNDERGROUND RISERS, SERVING SUPAI VILLAGE	2015	No
PEACH SPRINGS SYSTEM & INDIAN 18 POLE INSPECTION	2015	Yes
INSTALLATION OF 48 FAULT INDICATORS - INDIAN 18	2017	

**Individual assets may have been upgraded*

Mohave Electric Cooperative (MEC) provided data to March 31, 2017 regarding the Peach Springs Asset Base Gross Book Value (i.e. cost of assets at installation date without any deductions since). It is shown comparatively to the 2007 Study RCN value (i.e. the estimated gross book value at that time):

Table 4: Peach Springs Distribution Gross Plant Provided by MEC, 2017 compared to 2007 Study[2]

		2007 Study	2017 MEC Data	
Code	**Distribution Asset Category**	**RCN**	**Quantity (#)**	**Gross Book Value**
364	Poles, Towers & Fixtures	$ 1,436,520	5,741	$ 552,337
365	Overhead Conductors & Devices	$ 1,576,661	2,291,221	648,783
366	Underground Conduits	$ 13,782	2,280	2,597
367	Underground Conductors & Devices	$ 23,570	-	$ -
368	Transformers	$ 451,753	296	$ 449,597
369	Services	$ 197,600	480	$ 56,878
370	Meters	$ 61,664	521	$ 142,115
373	Street Lighting & Signal System	$ 58,566	35	$ 8,906
	Total	**$ 3,820,116**	**2,300,574**	**$ 1,861,211**

MEC latest General Rate Application provides a breakdown of accumulated depreciation by asset category. Accumulated depreciation for the Distribution Plant for year ending 2015 is 29% of gross book value (i.e. 29% of the total assetbase in service has already been paid for through rates).[3] Comparatively, the 2007 Valuation Study approximated 83.4% of gross book value was depreciated specific for Peach Springs assets. Using both to provide a range of potential outcomes, the expected net book value would be between $0.3 million and $1.3 million shown below.

[2] Information provided by MEC sorted as follows: Account 364 consists of structures and assemblies (less area lights), 365 includes all OH and ACSR listed wires in conductors, less services wires, 366 includes all UG wires (and implicitly account 367), 368 includes Transformers and 1PH Regulator Bank asset, 369 includes all Service Wires in the Conductors category, 370 includes Meters assets and Primary Metering assets, 373 includes the 100W HPS Area Light asset listing within the assemblies category.

[3] MEC Rate Change Application 7.26.16, Notes to Financial Statements page 10 (pdf page 40 of 251) provides net book value (utility plant plus accumulated depreciation) of $74.64 million for 2015, page 11 (pdf page 41 of 251) provides distribution plant accumulated depreciation of $30.33 million for 2015. Adding the two, gross utility plant for distribution assets is $104.97 million. Dividing accumulated depreciation by gross utility plant gives you 29%.

Table 5: Estimated Net Book Value Calculation

		2017 MEC Data	MEC Total Distribution Plant Acc. Depreciation Avg		2007 Valuation Acc. Depreciation Weighting	
Code	**Distribution Asset Category**	**Gross Book Value**	**Estimated Accumulated Depreciation (MEC Average)**	**Estimated Net Book Value (OCLD)**	**Estimated Accumulated Depreciation (2007 Report %)**	**Estimated Net Book Value (OCLD)**
364	Poles, Towers & Fixtures	$ 552,337	$ 159,601	$ 392,736	$ 460,653	$ 91,684
365	Overhead Conductors & Devices	648,783	$ 187,469	$ 461,314	$ 541,089	$ 107,694
366	Underground Conduits	2,597	$ 750	$ 1,846	$ 2,166	$ 431
367	Underground Conductors & Devices	$ -	$ -	$ -	$ -	$ -
368	Transformers	$ 449,597	$ 129,913	$ 319,683	$ 374,967	$ 74,630
369	Services	$ 56,878	$ 16,435	$ 40,443	$ 47,436	$ 9,441
370	Meters	$ 142,115	$ 41,065	$ 101,050	$ 118,525	$ 23,590
373	Street Lighting & Signal System	$ 8,906	$ 2,573	$ 6,333	$ 7,428	$ 1,478
	Total	**$ 1,861,211**	**$ 537,806**	**$ 1,323,405**	**$ 1,552,262**	**$ 308,949**

Given that known system improvements and additions provided by MEC have been minimal (table provided above), it is more than likely that Peach Springs specific assets are older in age on average than MEC's collective system and as a result, accumulated depreciation would be higher than the MEC Distribution Plant average of 29%. Therefore, the net book value estimate is more likely closer to the low end of the range.

In addition, the assetbase as provided by MEC includes assets on Hualapai reserve land that is not explicitly serving Peach Springs. Acquisition cost estimates include these amounts as it is not apparent that MEC would be willing to separate them or if the HTUA would want to exclude these assets even though they are on the extra-territorial land. For reference, MEC has provided an inventory of these assets, with a gross book value of $0.3 million, as shown in the table below.

Table 6: Gross Book Value of Assetbase Not Serving Reservation

Code	Distribution Asset Category	Quantity (#)	Gross Book Value
364	Poles, Towers & Fixtures	993	$ 91,522
365	Overhead Conductors & Devices	488,311	$ 148,718
366	Underground Conduits	-	-
367	Underground Conductors & Devices	-	$ -
368	Transformers	2	$ 69,059
369	Services	5	$ 554
370	Meters	7	$ 2,221
373	Street Lighting & Signal System	-	$ -
	Total	**489,318**	**$ 312,073**

Acquisition Cost

Using the estimated net book value estimate (which would approximate the OCLD figure defined above) of $308,949 an approximate purchase price for the assets would likely include a multiplier (i.e. MEC would require asset value plus some level of return). The 2007 Valuation Report uses a 1.4 to 1.6 times OCLD range as the most common range for negotiated sales.[4] Using the midpoint of 1.5 times OCLD results in an asset purchase price of approximately $463,423. The calculation for this is provided in the table below based off the estimated netbook value.

Table 7: Estimated Acquisition Cost (1.5 times OCLD)

		2017 MEC Data		2007 Valuation Acc. Depreciation Weighting		
Code	**Distribution Asset Category**	**Quantity (#)**	**Gross Book Value**	**Estimated Accumulated Depreciation (2007 Report %)**	**Estimated Net Book Value (OCLD)**	**Estimated Acquisition Value (1.5xOLCD)**
364	Poles, Towers & Fixtures	5,741	$ 552,337	$ 460,653	$ 91,684	$ 137,526
365	Overhead Conductors & Devices	2,291,221	648,783	$ 541,089	$ 107,694	$ 161,540
366	Underground Conduits	2,280	2,597	$ 2,166	$ 431	$ 647
367	Underground Conductors & Devices	-	$ -	$ -	$ -	$ -
368	Transformers	296	$ 449,597	$ 374,967	$ 74,630	$ 111,945
369	Services	480	$ 56,878	$ 47,436	$ 9,441	$ 14,162
370	Meters	521	$ 142,115	$ 118,525	$ 23,590	$ 35,385
373	Street Lighting & Signal System	35	$ 8,906	$ 7,428	$ 1,478	$ 2,218
	Total	**2,300,574**	**$ 1,861,211**	**$ 1,552,262**	**$ 308,949**	**$ 463,423**

The use of the 1.5 times metric is to approximately represent that in an acquisition, the seller does not commonly settle at the netbook value or rate base value, it will seek and typically receive a premium. It's not determinative what MEC will require, so there is room in the negotiation to secure a reduced acquisition value from the estimate above. In addition, this asset valuation is based on an assumed 83.4% depreciation value (from the 2007 study, explained above). This level of depreciation would also have to be determined in an acquisition negotiation.

Acquisition Cost - Annualized (Principal & Interest)

Assuming a loan is secured through the Rural Utilities Services (RUS), current Municipal interest rates offered through the RUS for a 20 year loan (terms ending in 2038 or later) are 3.00%, although these rates are subject to approval and change daily.[5] Assuming a 50 basis point premium to account for near-term interest rate changes or factors in loan approval consideration (such as the age of the system), a 3.50% interest rate was used to annual the acquisition cost value for development of a revenue requirement. The combined annual

[4] 2007 Hualapai Utility Authority Feasibility Report, Appendix A: Preliminary Assessment of Distribution System, page 5

[5] Municipal Interest Rates for the 4th Quarter of CY 2017, as of November 8, 2017. Available online: https://www.rd.usda.gov/programs-services/services/rural-utilities-loan-interest-rates

Principal and Interest costs of this would be approximately $32,607 per year. The annual breakdown is provided in the table below.

Table 8: Annualized Principal and Interest Repayment of a 20-year loan with the RUS for $463,423 at 3.5% Annual Interest

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Principal Repayment	16,387	16,961	17,554	18,169	18,805	19,463	20,144	20,849	21,579	22,334
Interest Repayment	16,220	15,646	15,053	14,438	13,802	13,144	12,463	11,758	11,028	10,273
Total	**32,607**	**32,607**	**32,607**	**32,607**	**32,607**	**32,607**	**32,607**	**32,607**	**32,607**	**32,607**
Year	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
Principal Repayment	23,116	23,925	24,762	25,629	26,526	27,454	28,415	29,410	30,439	31,504
Interest Repayment	9,491	8,682	7,845	6,978	6,081	5,153	4,192	3,197	2,168	1,103
Total	**32,607**	**32,607**	**32,607**	**32,607**	**32,607**	**32,607**	**32,607**	**32,607**	**32,607**	**32,607**

Each interest rate increase of 1% represents approximately $3,000 in additional annual repayment costs (e.g. if the annual interest rate is 4.5%, the combined annual principal and interest costs are approximately $35,600).

Capital Reinvestment/Replacement Annualized

As the system being purchased is quite aged (average age of 53 years in the 2009 Updated Study, with minimal system improvements/replacements in the intervening years) it is anticipated that the system maintenance and replacement costs could be quite high in the early years of operation (e.g., first 10 years).

On average it is assumed that a distribution system will need replacement at a rate of 3% per year (MEC's distribution plant has an average service life of around 30 or more years depending on the asset class, and depreciates its distribution plant under the straight-line composite basis of 3% per year[6] consistent with the Uniform System of Accounts as prescribed by the Rural Utilities Service (RUS)[7]). As an example, MEC's current average service lives for applicable Distribution Plant assets is shown in the table below.

[6] MEC Rate Change Application 7.26.16, Notes to Financial Statements page 11 (pdf page 41 of 251)
[7] MEC Rate Change Application 7.26.16, Notes to Financial Statements page 8 (pdf page 38 of 251)

Table 9: Distribution Plant Average Service Lives[8]

Distribution Plant	Depreciation Rate	*Calculated Average Service Life*
364.00 Poles, Towers & Fixtures	3.00%	*33*
365.00 Overhead Conductors & Devices	2.30%	*43*
366.00 Underground Conduits	1.80%	*56*
367.00 Underground Conductors & Devices	2.40%	*42*
368.00 Transformers	2.60%	*38*
369.00 Services	3.10%	*32*
370.00 CTs, PTs, Etc. & Meters	5.54%	*18*
370.00 Bases	10.00%	*10*
370.00 Other AMI Equipment	12.94%	*8*
373.00 Street Lighting & Signal System	3.80%	*26*

To calculate an annual reinvestment cost, the Gross Book Value (i.e. OCLD) will not be sufficient as the past cost to install assets will not equate to the cost of replacement today. Therefore, using the 2007 Replacement Cost New estimate ($3.82 million), inflated at 3% per year for 10 years, the 2017 RCN is approximately $5.1 million.

While this should be considered a low estimate, at an annual replacement cost of 3% a year, annual replacement costs would equate to approximately $155,000 per year. As the Peach Springs system may be approaching 60 years average age (double the average service life of the system) it is likely this amount could be higher in the initial serviceable years.

Potential cost savings exist in the form of RUS Electric Program grants, loans and loan guarantees for construction of electric distribution, transmission, and generation facilities (including system improvements and replacement) as well as demand side management, energy efficiency and conservation programs and on-grid and off-grid renewable energy systems.[9]

Additionally, it is not a given that this level of funds would be required each and every year, there could be consideration for a stepped approach at adding these costs in rates in an effort to pace the rate increases required upon system acquisition to break even. However, lenders will often consider secured annual cash flow as a benefit when approving loans. It is recommended that this level of costs should be collected each year, and held in reserve if unused at year end (to save for the years when more than this amount is required). This will help ensure longer-term rate stability for customers.

[8] MEC Rate Change Application 7.26.16, Schedule C-2.12, page 1of 2 (pdf page 112 of 251)
[9]United States Department of Agriculture Rural Development Electric Programs website. Available online: https://www.rd.usda.gov/programs-services/all-programs/electric-programs

Operating, Maintenance, Administrative, & General Costs

Annual maintenance costs for the last nine months of 2016 and for the first eight months of 2017 were provided by MEC and vary considerably month to month. On average between the data provided for 2016 and 2017 monthly maintenance is estimated at $8,000. On an annualized basis this is $96,000 per year.

Table 10: Peach Springs Monthly Maintenance Costs per MEC

	2016	2017
January		$ 15,723
February		$ 1,941
March		$ 17,991
April	$ 5,791	$ 5,829
May	$ 39,323	$ 6,740
June	$ 12,316	$ 7,312
July	$ 2,376	$ 2,359
August	$ 1,789	
September	$ 2,617	
October	$ 2,718	
November	$ 941	
December	$ 2,087	
Monthly Avg.	**$ 7,773**	**$ 8,271**

Depending on agreements made, if HTUA retains MEC to continue maintenance of the system (if this is possible) it is likely that the costs charged will be higher and incorporate a return component. In the long-term, as the system is slowly replaced, it is expected these costs would slowly decrease on a real basis (i.e. not including the inflation).

Administrative & General costs were contemplated in the 2007 and 2009 feasibility studies. Annual forecast costs for the in house administrative services (assume this includes salaries & wages, benefits and system costs) was $113,974 in the 2007 Feasibility and $127,400 for the 2010 year in the 2009 update. Adjusting for inflation, the annual Administrative and General costs from these earlier reports would be approximately $150,000 per year.[10]

Comparing to other rural utilities of a similar size, the combined forecast operating and maintenance costs for Peach Springs are far lower on per customer basis as shown in the table below.

[10] Assuming 2.5% inflation for 7 years to the 2010 forecast of $127,400 is approximately $150k.

Table 11: Operating, Administrative & Maintenance Cost Comparison to Similar Sized Rural Utilities

	Peach Springs 2017 Update Feasibility	Kotzebue Electric Assn (Alaska) [2015]	Fishers Island Electric Corporation (New York) [2015]	Pleasant Hill Community Line (Iowa) [2015]
Ownership		Cooperative	Investor Owned	Cooperative
Revenues ($000s)	828	7,906	2,166	421
Sales (MWh)	8,073	19,889	6,032	4,497
Customers	359	1,268	759	116
Avg. Energy Rate (cents/kWh)	10.26	39.75	35.91	9.36
Operating & Maintenance Costs ($000s)	246	1,581	795	237
O & M per Customer ($)	**685**	**1,247**	**1,047**	**2,046**

Power Supply Costs

MEC provided 2016 and partial 2017 power supply costs for the Hualapai Tribe as provided in the Table below. Monthly averages are also provided to compare how 2017 is tracking compared to 2016. In general, transmission costs are higher for 2017 than 2016 while energy costs are slightly reduced. The reason for the cost fluctuation is not clear but likely involves as required third party transmission purchases by MEC that are passed through to the Hualapai Reservation.

Table 12: 2016 and Partial 2017 Power Supply Costs from MEC

Annual	2016 - Jan-Dec	2017 - Jan-Aug
Energy	$ 543,801.71	$ 355,351.55
Transmission	$ 4,869.62	$ 17,855.22
Total	**$ 548,671.33**	**$ 373,206.77**
Monthly Average	**2016**	**2017**
Energy	$ 45,316.81	$ 44,418.94
Transmission	$ 405.80	$ 2,231.90
Total Average	**$ 45,722.61**	**$ 46,650.85**

The provided power supply costs include the reduced revenues from the negative rate rider included in rates for 2016 and 2017 by MEC. Transmission costs above do not include the costs to use MEC's transmission assets, as this is included elsewhere in the rate. The charge listed is only external transmission costs incurred by MEC to deliver power to the MEC grid. As a standalone utility, HTUA would be required to secure transmission services which, for at least the near-term, would likely require continued use of MEC transmission, but at a cost which has not been previously set by MEC, which does not have a wholesale wheeling rate in place.

The forecast power supply costs (including generation and transmission) are based on a rate of 7.825 cents/kWh. This is established based on MEC's 2016 Rate Application forecast power supply costs for the test year December 31, 2015 (i.e. the power supply costs approved in the latest MEC rate application). Total costs include generation, transmission, service charges, and other power supply costs (including service charges, hedging, scheduling, etc.) and adjustments, as shown in the Table below. In addition, MEC's transmission O&M costs are included in this rate as a proxy for a wheeling charge that may be charged if MEC acts as a third-party transmission provider. This estimated cost will not include any costs associated with the Nelson substation.

Table 13: Power Supply Cost Breakdown[11]

		MEC Test Year 12/31/2015
Generation Charges		
Purchased Power (including hedging, scheduling & planning service charges, and other charges)		45,036,215
Solar Energy (including ACC REST Allocation)		229,496
Total Generation		**45,265,711**
Total Transmission		**6,204,578**
Economy Purchases		**29,201**
Total Cost of Power		**51,499,490**
Adjustments	-	117,919
Transmission O&M		**34,972**
Total Power Supply		**51,416,543**
kWh		657,110,832
cents/kWh - Power Supply		**7.825**
cents/kWh - transmission		0.950
cents/kWh - generation		6.875
Peach Springs 2016 Load (kWh)		8,073,132
Peach Springs Power Supply Costs	**$**	**631,693**
Transmission	$	76,658
Generation	$	555,035

Based on total kWh usage by Peach Springs in 2016 (8,073,132 kWh), the total generation power supply forecast based on 2016 Peach Springs energy usage is $631,693 at MEC approved power supply costs[12].

[11] MEC Rate Change Application for Test Year December 31, 2015, Schedule E-7.6 (starting pdf page 130 of 251).

[12] Based on 7.825 cents/kWh 2015 test year generation power supply costs of $51.4 million divided by MEC total forecast energy usage of 657.1 GWh from MEC's 2016 Rate Change Application for test year ending December 31, 2015, Attachment 4, MEC Financial Section of Rate and Cost of Service Study, Schedule C-1.0 Adjusted Test Year Income Statement for Year ending 12/31/2015 (pdf page 84 of 251)

MEC currently has added a monthly rate rider to adjust for lower than forecast generation costs in 2016 and 2017. The current rider in place reduces energy rates charged to customers by 1.75 cents/kWh. Therefore the current power supply cost (up to the Nelson substation) is 6.075 cents/kWh. Applying this reduction to the forecast kWh usage for Peach Springs, power supply costs reduce to $490,414[13]. Note, this reduction to costs has an equal offset reduction to revenue and is not necessarily representative of future power supply costs.

If the HTUA uses MEC as a third party to purchase energy or instead purchases directly from Arizona Electric Power Cooperative Inc. (AEPCO), Western or APS, power supply costs will likely be higher due to increased transmission/wheeling charges as it is likely MEC would charge over the average level of O&M costs incorporated in this estimate.

Total Forecast Annual Utility Operating Costs

Total projected annual costs are provided in the tables below with the 2007 and 2009 feasibility comparisons. Table 14 estimates generation supply costs at the rate approved in the 2016 Rate Change Application. Total projected costs are estimated to be slightly over $1 million for 2018 as seen in Table 14.

Table 15 includes a reduction to the cost of generation power supply on a cents/kWh basis as consistent with prices paid today due to a monthly reduction rider in place of 1.75 cents/kWh. At this current rate of generation in place for 2017 (without inclusion of a transmission charge for power delivery) estimated annual costs are $924,020 in 2018.

In the 2007 and 2009 Feasibility studies, power supply costs represented approximately 65% and 75% respectively for total annual costs in the 2010 forecast year. Approximately one quarter of this was transmission related power supply in both cases, with the remainder representing generation costs. For the 2018 forecast test year, transmission power supply costs are not included, but generation related power supply costs have increased slightly as a percentage of total annual costs (for the table without inclusion of the reduction rider, approximately 59% of total revenue requirement). Presumably this includes a portion of third party transmission costs, which were minimal in cost for 2016 (see above table). Nevertheless, the total forecast annual operating costs likely underestimates the cost associated with transmission delivery charges.

[13] Estimated at 6.075 cents/kWh, based on previous estimate of 7.825 cents/kWh less the negative 1.75 cents/kWh monthly rate rider (PCA) in place as of December, 2015 (and currently in place for rates in 2017) multiplied by forecast load of 8.07 GWh as shown in Tables 17 and 18.

Table 14: Forecast Annual Revenue Requirement Based on Updated Asset Cost Data from MEC ($ Dollars) – 2016 MEC Approved Power Supply Costs[14]

	2018 Test Year			2010 Forecast Year						
Peach Springs Annual Revenue Requirement	**MEC Adjusted Test Year**		**MEC cents/ kWh**	**2007 Study**		**2007 cents/ kWh**	**2009 Update**		**2009 cents/ kWh**
Power Supply (Generation)	**$**	**631,693**	**7.82**	$	337,509	5.35	$	582,314	6.08
Power Supply (Transmission)	$	-	-	$	119,916	1.90	$	191,998	2.01
OM&C - Distribution Related	$	96,000	1.19	$	50,206	0.80	$	105,554	1.10
OM&C - Customer Related	$	-	-	$	11,569	0.18			-
Administrative & General	$	150,000	1.86	$	113,974	1.81	$	127,400	1.33
Asset Replacement	$	155,000	1.92						
Depreciation/Debt Service - Principal	$	16,387	0.20	$	8,290	0.13			-
Finance Expense/Debt Service - Interest	$	16,220	0.20	$	62,560	0.99	$	39,623	0.41
Other Expenses (tax)	$	-	-			-			-
Reserves			-	$	5,306	0.08	$	5,000	0.05
Total Projected Costs	**$**	**1,065,300**	**13.20**	**$**	**709,330**	**11.25**	**$**	**1,051,889**	**10.99**

Table 15: Forecast Annual Revenue Requirement Based on Updated Asset Cost Data from MEC ($ Dollars) – Adjusted for Power Supply Interim Rate Reductions

	2018 Test Year			2010 Forecast Year					
Peach Springs Annual Revenue Requirement	**MEC Adjusted Test Year**		**MEC cents/ kWh**	**2007 Study**		**2007 cents/ kWh**	**2009 Update**		**2009 cents/ kWh**
Power Supply (Generation)	**$**	**490,414**	**6.075**	$	337,509	5.35	$	582,314	6.08
Power Supply (Transmission)	$	-	-	$	119,916	1.90	$	191,998	2.01
OM&C - Distribution Related	$	96,000	1.19	$	50,206	0.80	$	105,554	1.10
OM&C - Customer Related	$	-	-	$	11,569	0.18			-
Administrative & General	$	150,000	1.86	$	113,974	1.81	$	127,400	1.33
Asset Replacement	$	155,000	1.92						
Depreciation/Debt Service - Principal	$	16,387	0.20	$	8,290	0.13			-
Finance Expense/Debt Service - Interest	$	16,220	0.20	$	62,560	0.99	$	39,623	0.41
Other Expenses (tax)	$	-	-			-			-
			-						
Reserves			-	$	5,306	0.08	$	5,000	0.05
Total Projected Costs	**$**	**924,020**	**$ 11.45**	**$**	**709,330**	**11.25**	**$**	**1,051,889**	**10.99**

The differential in generation power supply costs (first row) for the 2018 test year between the above two tables is caused by inclusion of the 1.75 cent/kWh monthly rider reduction for 2017 in the second table. This cost reduction (from 7.825 cents/kWh to 6.075 cents/kWh) is offset by a corresponding decrease to forecast revenues, as seen in the table below.

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[14] 2018 cents/kWh calculation uses updated 2016 actual load data shown in the table below. For 2007 and 2009 feasibility the asset replacement costs were bundled with the principal and interest (debt servicing) costs.

Peach Springs Revenue to Cost Comparison

MEC provided updated load data for Peach Springs in fall 2017. Previous load data used was missing a few new accounts that had been added. The result of the updated load data is an increase in annual energy usage, for 2016 total was 8.07 GW.h. This is shown in Table 17 (without rider) and Table 18 (with rate rider). At MEC approved 2017 rates (with riders) this would provide $687,172 in annual revenues. Without the rate rider factored in (i.e. at approved power supply costs in MEC's 2016 Rate Change Application) revenues are forecast at $828,452. The resulting revenue to revenue requirement shortfall is provided in the table below.

Table 16: Estimated Revenue to Cost Comparison at Existing MEC Rates (with and without rate rider reduction to revenue and power supply cost), Updated Load Forecast and Updated Asset Valuation Data

	Revenue		Costs		*Difference*		Rate
	$	¢/kWh	$	¢/kWh	***$***	***¢/kWh***	**Increase**
2017 Estimate (without power supply rate reduction rider)	**828,452**	**10.26**	**1,065,300**	**13.20**	***-236,848***	***-2.93***	**28.6%**
2017 Estimate (with power supply rate reduction rider)	**687,172**	**8.51**	**924,020**	**11.45**	***-236,848***	***-2.93***	**34.5%**
2007 Feasibility (2010 forecast year)	580,403	9.21	709,330	11.25	*-128,927*	*-2.05*	22.2%
2009 Feasibility (2010 forecast year)	834,638	8.72	1,051,889	10.99	*-217,251*	*-2.27*	26.0%

Based on these estimates, the acquisition of distribution assets from MEC would result in an average rate increase of 28.6% in order to break even in the initial year. If adjusting for the current cost of generation, a rate increase of 34.5% from current electricity bills would be required.

Table 17: Peach Springs Forecast Load, Revenue and Average Rates Comparison 2007 Feasibility, 2009 Update and MEC Actuals – Updated with Adjusted Load from MEC[1]

			Peach Springs Actual						
Load	**2010 Forecast Year**		**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2016**
Rate	**2007 Feasibility (2010 forecast year)**	**2009 Feasibility (2010 forecast year)**	**MEC Average Rate (1991 approved rate)**	**MEC Average Rate (2012 approved rate)**	**MEC Average Rate (2012 approved rate)**	**MEC Average Rate (2012 approved rate)**	**MEC Average Rate (2012 approved rate)**	**MEC Average Rate (2012 approved rate)**	**MEC Average Rate (2017 approved rate)**
Residential									
kWh	2,933,587	2,995,894	2,953,423	2,899,603	3,048,626	2,859,231	2,985,476	3,031,212	3,031,212
revenue	$ 286,939	$ 294,576	$ 286,555	$ 353,882	$ 368,487	$ 350,105	$ 362,083	$ 366,476	$ 373,774
Average Consumers	377	362	358	358	360	360	359	358	358
Avg. Energy Rate (cents/kWh)	**9.78**	**9.83**	**9.70**	**12.20**	**12.09**	**12.24**	**12.13**	**12.09**	**12.33**
Small Commercial - Energy									
kWh	2,352,795	2,369,972	849,158	922,709	925,949	915,793	1,011,152	970,178	970,178
revenue	$ 219,514	$ 229,736	$ 79,971	$ 115,719	$ 117,172	$ 116,122	$ 127,203	$ 123,957	$ 126,573
Average Consumers	73	82	74	79	83	83	88	92	92
Avg. Energy Rate (cents/kWh)	**9.33**	**9.69**	**9.42**	**12.54**	**12.65**	**12.68**	**12.58**	**12.78**	**13.05**
Small Commercial - Demand									
kWh			1,522,180	1,627,182	1,634,968	1,643,650	2,090,987	2,058,822	2,058,822
revenue			$ 91,011	$ 132,451	$ 134,231	$ 135,640	$ 170,129	$ 168,087	$ 171,830
Average Load Factor			33.7%	35.5%	34.5%	33.6%	35.7%	35.4%	35.4%
Average Consumers			17	18	21	22	23	24	24
Avg. Energy Rate (cents/kWh)			**5.98**	**8.14**	**8.21**	**8.25**	**8.14**	**8.16**	**8.35**
Small Commercial - Total									
kWh	2,352,795	2,369,972	2,371,338	2,549,891	2,560,917	2,559,443	3,102,139	3,029,000	3,029,000
revenue	219,514	229,736	170,982	248,170	251,403	251,762	297,332	292,044	298,403
Average Load Factor	0.0%	0.0%	33.7%	35.5%	34.5%	33.6%	35.7%	35.4%	35.4%
Average Consumers	73	82	91	97	104	105	111	116	116
Avg. Energy Rate (cents/kWh)	**9.33**	**9.69**	**7.21**	**9.73**	**9.82**	**9.84**	**9.58**	**9.64**	**9.85**
Large Commercial									
kWh	1016712	4,205,027	2,183,000	2,202,040	2,127,800	1,937,880	2,146,120	2,012,920	2,012,920
revenue	$ 73,950	$ 310,326	$ 107,616	$ 167,423	$ 162,329	$ 148,597	$ 163,939	$ 153,827	$ 156,275
Load Factor	50.0%	50.0%	51.1%	53.9%	51.2%	51.1%	48.6%	53.3%	53.3%
Average Consumers	2	5	4	4	4	4	4	4	4
Avg. Energy Rate (cents/kWh)	**7.27**	**7.38**	**4.93**	**7.60**	**7.63**	**7.67**	**7.64**	**7.64**	**7.76**
Total									
kWh	**6,303,094**	**9,570,893**	**7,507,761**	**7,651,534**	**7,737,343**	**7,356,554**	**8,233,735**	**8,073,132**	**8,073,132**
revenue	**580,403**	**834,638**	**565,153**	**769,475**	**782,218**	**750,465**	**823,354**	**812,347**	**828,452**
Average Consumers	**378**	**363**	**359**	**359**	**361**	**361**	**360**	**359**	**359**
Avg. Energy Rate (cents/kWh)	**9.21**	**8.72**	**7.53**	**10.06**	**10.11**	**10.20**	**10.00**	**10.06**	**10.26**

[1] MEC average energy rate based on rates approved in Arizona Corporation Commission Decision No. 75931, dated January 13, 2017. Actual Peach Springs load and energy is used for kWh calculation for each year 2011 to 2016; as provided by MEC. Residential energy rate for MEC switched to a block structure for the 2012 rate. For simplicity, it is assumed 60% of load for residential is in the first block, 30% in second block and 10% in third block based on a cursory review of average annual use for this class in the 2013 year.

Table 18: Peach Springs Forecast Load, Revenue and Average Rates Comparison 2007 Feasibility, 2009 Update and MEC Actuals (with rate riders) – Updated with Adjusted Load from MEC[2]

Load	2010 Forecast Year		Peach Springs Actual						
			2011	2012	2013	2014	2015	2016	2016
Rate	**2007 Feasibility (2010 forecast year)**	**2009 Feasibility (2010 forecast year)**	**MEC Average Rate (1991 approved rate w 2011 rider)**	**MEC Average Rate (2012 approved rate w 2012 rider)**	**MEC Average Rate (2012 approved rate w 2013 rider)**	**MEC Average Rate (2012 approved rate w 2014 rider)**	**MEC Average Rate (2012 approved rate w 2015 rider)**	**MEC Average Rate (2012 approved rate w 2016 rider)**	**MEC Average Rate (2017 approved rate w 2017 rider)**
Residential									
kWh	2,933,587	2,995,894	2,953,423	2,899,603	3,048,626	2,859,231	2,985,476	3,031,212	3,031,212
revenue	$ 286,939	$ 294,576	$ 343,285	$ 381,065	$ 368,753	$ 334,391	$ 323,159	$ 313,694	$ 320,728
Average Consumers	377	362	358	358	360	360	359	358	358
Avg. Energy Rate (¢/kWh)	**9.78**	**9.83**	**11.62**	**13.14**	**12.10**	**11.70**	**10.82**	**10.35**	**10.58**
Small Commercial - Energy									
kWh	2,352,795	2,369,972	849,158	922,709	925,949	915,793	1,011,152	970,178	970,178
revenue	$ 219,514	$ 229,736	$ 96,282	$ 124,369	$ 117,172	$ 111,009	$ 113,931	$ 106,979	$ 109,595
Average Consumers	73	82	74	79	83	83	88	92	92
Avg. Energy Rate (¢/kWh)	**9.33**	**9.69**	**11.34**	**13.48**	**12.65**	**12.12**	**11.27**	**11.03**	**11.30**
Small Commercial - Demand									
kWh			1,522,180	1,627,182	1,634,968	1,643,650	2,090,987	2,058,822	2,058,822
revenue			$ 120,249	$ 147,706	$ 134,231	$ 126,463	$ 142,685	$ 132,058	$ 135,800
Average Load Factor			33.7%	35.5%	34.5%	33.6%	35.7%	35.4%	35.4%
Average Consumers			17	18	21	22	23	24	24
Avg. Energy Rate (¢/kWh)			**7.90**	**9.08**	**8.21**	**7.69**	**6.82**	**6.41**	**6.60**
Small Commercial - Total									
kWh	2,352,795	2,369,972	2,371,338	2,549,891	2,560,917	2,559,443	3,102,139	3,029,000	3,029,000
revenue	219,514	229,736	216,532	272,075	251,403	237,472	256,616	239,037	245,395
Average Load Factor	0.0%	0.0%	33.7%	35.5%	34.5%	33.6%	35.7%	35.4%	35.4%
Average Consumers	73	82	91	97	104	105	111	116	116
Avg. Energy Rate (¢/kWh)	**9.33**	**9.69**	**9.13**	**10.67**	**9.82**	**9.28**	**8.27**	**7.89**	**8.10**
Large Commercial									
kWh	1016712	4,205,027	2,183,000	2,202,040	2,127,800	1,937,880	2,146,120	2,012,920	2,012,920
revenue	$ 73,950	$ 310,326	$ 149,547	$ 188,068	$ 162,329	$ 137,777	$ 135,771	$ 118,601	$ 121,049
Load Factor	50.0%	50.0%	51.1%	53.9%	51.2%	51.1%	48.6%	53.3%	53.3%
Average Consumers	2	5	4	4	4	4	4	4	4
Avg. Energy Rate (¢/kWh)	**7.27**	**7.38**	**6.85**	**8.54**	**7.63**	**7.11**	**6.33**	**5.89**	**6.01**
Total									
kWh	**6,303,094**	**9,570,893**	**7,507,761**	**7,651,534**	**7,737,343**	**7,356,554**	**8,233,735**	**8,073,132**	**8,073,132**
revenue	**580,403**	**834,638**	**709,364**	**841,208**	**782,484**	**709,640**	**715,546**	**671,331**	**687,172**
Average Consumers	**452**	**449**	**453**	**459**	**468**	**470**	**474**	**478**	**478**
Avg. Energy Rate (¢/kWh)	**9.21**	**8.72**	**9.45**	**10.99**	**10.11**	**9.65**	**8.69**	**8.32**	**8.51**

[2] MEC average energy rate based on rates approved in Arizona Corporation Commission Decision No. 75931, dated January 13, 2017. Actual Peach Springs load and energy is used for kWh calculation for each year 2011 to 2016; as provided by MEC. Residential energy rate for MEC switched to a block structure for the 2012 rate. For simplicity, it is assumed 60% of load for residential is in the first block, 30% in second block and 10% in third block based on a cursory review of average annual use for this class in the 2013 year.

7.0 Interview Summaries with WAPA & MEC re: Power Supply

Conversations Regarding Potential Power Supply Options (Generation & Transmission) for HTUA with WAPA & MEC – Summary Notes

1.0 Summary of Discussion with Kevin Schaefer – Public Utilities Specialist (Rates), Western Area Power Administration (WAPA), Desert Southwest Region, February 15, 2018

On Boulder Canyon Project (BCP) - as you know there are two ways Hualapai receives power - directly and through APA. Hualapai is part of a 10-year benefit arrangement with Pechanga for D1 and a month-t-month bill credit with MEC for D2. We may be looking at directly use our D allocations in coming years based on the cost of service study or not.

The key thing Kevin emphasized is BCP power is not particularly good for prime wholesale supply as the allocations are uncertain until after the fact. This is because BCP power is not a system sale, it is participation power - Hualapai pay 0.0184% of the total costs, and receive 0.0184% of the capacity and energy, and carry all risks of performance of the project (i.e., in low water, bills don't go down but allocated power supplies do). WAPA does estimate the power delivered, and from that calculate a notional energy rate (this year 9.9989 mills/kW.h), and a notional demand rate (this year $1.9867 per kW/year), or an even simpler notional “composite rate” that includes the above costs (this year 19.98 mills/kW.h) but these are just notional to communicate an estimated average cost. The actual annual cost is fixed in advance but the power is whatever the plant generates – so there is no “rate” per se in the actual billing framework. Note that each of these notional rates is before fees of LCBDF and MSCP as well as repayable advances.

As a result, most parties are using BCP power for only a fairly small portion of their power needs such that the variability effect on wholesale costs would be fairly small. Hualapai will need to consider this as a risk factor in power supply costs.

Pricing was confirmed, and other applicable charges were discussed (included in model). He was not as useful on the charges they flow through from the Bureau of Reclamation (the Repayable Advances and the Multi Species Conservation Plan) but those are specified in your agreement. Repayable advances are only for 5 years, and I assume they started with the post-2017 contracts so we should probably include them in costs since they will be there for a while.

With regard to available capacity and energy, the sheet you forwarded (D1 allocation from APA, D2 allocation is only 184 MW.h) noted the estimate of 710 MW.h for 2018, which is consistent with his numbers. That is based on 3,849 GW.h entitlement (as compared to the 4,501 GW.h project total master schedule, before water constraints). For capacity, the 382 kW Hualapai receives as a percentage of nameplate (2,074 MW) translates in 2018 to a share of the 1,613 MW estimated capacity sales, totaling approximately 296 kW. Since this is pretty typical for the past few years (since at least 2005) I think we should use these allotments in estimating the rates.

I see APA's BCP values do a similar scaling, and for the same reason, I would suggest we use the 2018 allocation as the best estimate of future availability, recognizing the same notes regarding risk of lower flows (power allocation could go down without a reduction in costs for reasons such as drought, etc.). In this case, APA's nameplate allocation of 106 kW would be reduced to 67 kW, and total master scheduled energy of 233 MW.h would be reduced to 186 MW.h.

In regard to APA, I have not been in discussion with anyone there. I assume the files you sent, which note approximately $8000 inclusive of all fees and charges for this power, continue to be reasonable.

On service from WAPA over and above the BCP allocations, he was not knowledgeable, but will put me in touch with the right people to deal with.

Contact information for Kevin Schaefer:

Public Utilities Specialist (Rates)
Western Area Power Administration | Desert Southwest Region
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2.0 Summary of Discussion with Parker Wicks & Brent Oseik – Contracts and Energy Services Manager, WAPA, Salt Lake City, CRSP Management Center, February 21, 2018

Colorado River Storage Project (CRSP) allocation is different than BCP. In this case:

- Rates for power are set on a 5 year basis. A cross-check is performed annually to make sure rates are tracking costs, but generally there is no rate change outside the 5 year update. Customers can rely on the unit pricing.
- The composite rate is quoted presently at 29.42 mills/kW.h but this is comprised of $5.18/kW-month and 12.19 mills/kW.h – it is important to track these separately due to variations in allocation and in replacement power.
- The Hualapai allocation is 625 kW in summer and 608 kW in winter, but the annual allocations this year are only 320 kW as the SHP this year (sustainable level). This is typical, if not a bit higher than normal (this year Glen Canyon is scheduled to release 9 million acre-feet, while normal is 8.23 million acre-feet). On the energy side, the allocations are 1.163 GW.h in winter and 1.118 GW.h in summer, and this is the full contracted allocation (CROD) which is almost always the case (energy is not expected to be scaled back). Unlike BCP, these volumes, once projected, are committed by WAPA.
- The SLCIP contract also provided Hualapai with the right to receive additional power secured by WAPA at market prices up to the full capacity allocation at a 100% load factor (Western Replacement Power). This must be scheduled a month in advance, and paid in advance, but the actual prices (and true-up billing) will only occur after-the-fact based on market purchases. Because this can be used to get up to the full 100% load factor on the CRSP/SLCIP capacity allocation, there is a lot of power available to Hualapai through this route (over 3 million kW.h in 2017/18 over and above the 2.3

million provided through CRSP/SLCIP). Present forecasts are 25 mills/kW.h off-peak and 31-43 mills/kW.h on-peak. Most small utilities make use of Western Replacement – most large utilities do their own power acquisition.

- CRSP power has a delivery point of Pinnacle Peak. Further information is needed in regard to the delivery of this power within the Parker-Davis area (i.e., Round Valley sub) which I will follow up on.

They recommended a few further contacts. They also suggested speaking with John Steward re: Transmission, and Randy Manion who I don't recall hearing about before. They indicated Randy was technically a "renewable program coordinator" but has worked with other tribes re: utility service – I am not quite sure what specific information they thought Randy would be able to provide, but I'll put him on the list after John Paulsen (Friday) and John Steward (not yet scheduled) as well as Rick Campos (Friday).

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3.0 Summary of Discussion with John Paulsen – WAPA Manager of the Energy Management and Marketing Office (Desert Southwest Region), February 23, 2018

John is the Manager of the Energy Management and Marketing Office at WAPA for the Desert Southwest Region. In short, John was the source for the information on power supply options.
John noted that WAPA can be asked by HTUA, if it was operating as a utility, to purchase wholesale power for HTUA. This would be pursuant to a long-term contract that HTUA would sign with WAPA. John noted that this is a service WAPA provides, in competition with other market service providers, but that WAPA operates this service at cost. He indicated that WAPA would take care of all wholesale energy procurement and load balancing, but that the costs would be recovered from the amounts billed to HTUA. He noted that there would be fairly material costs incurred no matter who HTUA used for this service, but that for WAPA, it would mean HTUA would have to have high quality metering (he indicated that any estimate that we received from the transmission business unit was likely similar assumptions – recall that was the estimated $80k metering infrastructure) plus communications infrastructure and WAPS's service charges, which he estimated would run $40k-$60k (labour) per year.

John provided cost estimates of forward pricing at the present time (attached), in the attached file. Note however that (a) these are forward prices so no firm or guaranteed, (b) these are Palo Verde prices, to which he indicated we would need to assume an additional $3/MW.h for estimating Mead, (c) these are prices for 25 MW blocks, so we should assume $5/MW.h premium for purchasing partial blocks, (d) we would need to add 3% for bulk transmission losses. He noted that with WAPA ongoing load balancing, there would be no need to plan take-or-pay commitments (such that HTUA would not be required to purchase units it did not ultimately require). He also enumerated the ancillary services that HTUA would be required to purchase, including reactive supply and voltage control and regulation and frequency response (note that these are fairly low cost – total less $10k/year). Also there would be no need for purchasing capacity resources if HTUA bought under this model.

John was quick to note that MEC is a customer of theirs, and he is happy to work with HTUA to further refine power supply costs. At the same time, he did note that this would be easiest within the bounds of knowing that HTUA was working in concert with MEC – he was clearly concerned about being in the middle of any dispute.

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4.0 Summary of Discussion with John Steward – WAPA Transmission Business Unit Manager, February 23, 2018

John indicated transmission is effectively available to HTUA from WAPA under 2 systems – the federal allocations and the OATT purchases. Federal allocations can typically be secured for whatever capacity is required, while the OATTs work only in 1 MW blocks. For HTUA this likely means purchasing a 2 MW block throughout the year.

He discussed the OATT services available – point to point (PTP) or network integration (NI). In general, the point to point may be easier to implement to start, though a small cost savings may be possible in future through moving to network integration (though the rates for NI service are not as clear as they are determined by cost sharing, and the NI service is much less flexible).

For Round Valley delivery, the rates for all transmission deliveries are Parker Davis, and rates are as published on the WAPA website. They cannot provide an indication of future rates, but he noted WAPA has worked very hard to keep rates stable . He also noted any financial analysis must include the costs of a revenue quality meter (estimated at $80k – note this was echoed by later interviews).

John noted that transmission service required submitting an early request, and WAPA having to deal with allocations, but I would surmise from his statements that due to the small load size, they would be able to accommodate whatever HTUA load was required. The best option would be a Mead 230 delivery, given transmission loading.

In terms of future options, he noted that if new lines were required that Randy Minion should be approached as he has good knowledge of federal programs to help with that (absent federal programs, the cost is the customers to pay – WAPA will help with getting the project in place).

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5.0 Summary of Discussion with Rick Campos, Manager of Engineering, Operations and Energy Services for Mohave Electric Cooperative, February 23, 2018

The call started with review of InterGroup's purpose for being retained by HTUA, to consider the costs and implications of taking on the utility service in Peach Springs. Rick noted that he was generally aware that HTUA had made this type of objective known, but that no specific discussions had occurred about what this would take. As a result, Rick noted that MEC had not done any detailed work on such a plan, and so any comments were just an initial reaction, and subject to needing to involve other people, and with more time to consider, before a firm answer on many issues could be provided. Rick also noted that the Hualapai are valued members of the Mohave Electric Cooperative.

Rick noted that he had some discussions with HTUA over the years about reliability. He indicated that a number of projects were in the works that should work to incrementally improve the situation with respect to "blinks", some that have been completed and some that are still underway. On this list, he included the reconfiguration of the supply to the Lhoist lime plant (69 kV), reactors and voltage regulators, and measures to improve dust control. He also noted that improvements have been underway on the supply from the Hualapai substation. Some of these measures may take a few years to be fully implemented and to show results, and to then pin point the next issue to address, but incrementally the situation should be improving.

The most notable supply improvement possibility MEC indicated was any potential for an added supply source into the Nelson sub, such as from the APS or WAPA facilities. If something of that nature could be achieved as part of HTUA's mandate (i.e., a new transmission connection), then a substantial reliability benefit may be possible, but it was also noted that MEC had not studied this in any way, and had no idea of costs to achieve that. Such a supply option may merit study if the Hualapai loads were to be significantly expanded, such as concepts regarding water supply and large pumping loads.

On the concept of an HTUA utility taking over service in Peach Springs, a few matters were raised that we should all be aware of:

1) **Large Commercial Service:** If the configuration was to involve HTUA taking some form of large customer service from the Nelson substation, this option was likely possible, under existing large customer tariffs. Under this model, MEC would acquire the resources like it does now, and provide utility service to HTUA. Rick thought that this prohibited HTUA from reselling the power (MEC has a certificated area that includes the reservation), but that HTUA would need to deal with the ACC on that issue (if they have jurisdiction). For rates, the large commercial rate would qualify for

discounts depending on the voltage and delivery point for HTUA taking delivery, such as between 1% and 7.5% depending on these factors. The rate is presently $200 monthly, with demand at $10.98 per kW and 0.070513 energy per kW.h less 1.5 cents/kW.h offset rider. (Rates can be found on the MEC website)

2) **Wholesale service or wheeling:** If HTUA sought to secure a wholesale service from Nelson substation or look to pay a wheeling rate, etc., this would be very problematic for MEC, as MEC is only a distribution coop and therefore is not presently governed by complicated requirements that would kick in if transmitting wholesale power (i.e. NERC, FERC, WECC, etc.)). Other measures might be possible, like an O&M agreement that is not a wheeling rate per se, but that may prove complicated to develop. Any power transaction of this type would have to address APCO's assets at Round Valley.

3) **How to define assets:** There would be a need to be very clear about what assets were involved in any transfer, and the criteria for determining this basket of assets – for example, is it only to serve tribal members, or to serve all loads within the tribal boundary (it's thought to be the latter). There are non-tribal loads within the tribal boundary – things like rail signals, etc. As well there are MEC customers off the tribal lands but they are downstream of assets within the tribal boundaries, which MEC would/may have to continue to serve even if HTUA bought the assets, as it is part of MEC's certificated area. It is not immediately clear how that could be done. Finally, service to the west side of Peach Springs may be more complicated as that load is not presently served off the Nelson sub, but rather than Hualapai sub.

4) **MEC continued need to own some assets:** Regardless as to what assets changed hands, MEC would require ownership and full access to certain assets on Hualapai lands to maintain reliable supply. For example, MEC requires a means to connect Hualapai sub loads to the Nelson sub. This is presently done with the lines and a switch on the Hualapai lands. If HTUA looked to purchase these assets, MEC would need to build some new way of achieving the same result that remained under their control – either via lines off of Hualapai lands, or through new lines on Hualapai lands that MEC continued to own. In short, any purchase should assume there is some need for new line construction.

5) **Purchase price:** MEC would have very little flexibility regarding purchase price, as there would be two overriding external party standards that would have to be met – RUS guidelines in respect of anything that had RUS funding, and ACC guidelines in respect of any plan that may lead to increased costs for MEC members. The exact guidelines were not something that has been considered by MEC to date, but they would tend towards making sure that assets could not be transferred at less than Net Book Value, and in some cases MEC would have to see a greater value in order to get ACC's approval to show that existing customers were protected. For example, even if a sale a net book value may protect MEC's customer from net rate base growth, if MEC had to incur material costs to build a new connection between the Hualapai feed and the Nelson sub, then this cost would have to be done in a way that would not drive up rates for MEC's members – meaning the purchase would have to include a premium to compensate MEC for this cost in order to satisfy the ACC. MEC could/may not do anything on asset transfer if ACC did not revise MEC's certificated

area, so the ACC holds considerable control over any concept, even if their jurisdiction on tribal lands is limited.

6) **O&M:** It was asked of MEC, if HTUA was to take over the assets, whether MEC had ever taken on the job as a contract O&M or utility manager for another service area. Rick indicated that MEC had never done quite this role, but that MEC does at times implement O&M agreements with users, such as RV parks, that have their own distribution system such that MEC will do O&M work on call to deal with things like overhead utility equipment issues. MEC has have never taken on capital or O&M planning per se, just the cost recovery service provider when work is needed. Further discussion would be required to find out what might be possible here.

Rick said he would look into the values that were provided to InterGroup on the assets, and later confirmed those were original cost or gross book values. Further discussion is required regarding whether net book values would be able to be provided, as it may require some funding from HTUA for MEC to get this value.

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8.0 Palo Verde Forward Prices - WAPA

UPDATE

Palo Verde Forward Prices
2/05/2018

	On-Peak	Off-Peak	24x7
Q4 2017	$0.00	$0.00	$0.00
Q1 2018	$13.51	$12.73	$13.18
Q2 2018	$24.41	$19.39	$22.22
Q3 2018	$37.25	$21.94	$30.37
Q4 2018	$24.15	$21.44	$22.95
Q1 2019	$23.67	$22.71	$23.25
Q2 2019	$23.77	$18.83	$21.62
Q3 2019	$35.40	$23.39	$30.09
Q4 2019	$24.29	$23.00	$23.72
Q1 2020	$26.68	$25.50	$26.16
Q2 2020	$26.35	$21.50	$24.23
Q3 2020	$36.72	$25.90	$31.94
Q4 2020	$29.41	$25.45	$27.69
Q1 2021	$30.79	$27.41	$29.31
Q2 2021	$28.60	$23.12	$26.21
Q3 2021	$38.94	$28.49	$34.32
Q4 2020	$29.41	$25.45	$27.69
CY 2018	$24.79	$18.96	$22.23
CY 2019	$26.79	$22.00	$24.69
CY 2020	$29.80	$24.59	$27.52

Palo Verde Monthly Indexes
CY2011-Current

	On-Peak	Off-Peak
Jan-12	$ 27.02	$ 20.55
Feb-12	$ 26.17	$ 19.69
Mar-12	$ 22.58	$ 17.42
Apr-12	$ 21.47	$ 15.16
May-12	$ 26.31	$ 16.53
Jun-12	$ 28.76	$ 16.72
Jul-12	$ 32.70	$ 18.46
Aug-12	$ 42.06	$ 20.70
Sep-12	$ 30.53	$ 22.17
Oct-12	$ 33.46	$ 25.39
Nov-12	$ 29.37	$ 25.77
Dec-12	$ 29.86	$ 24.92
Jan-13	$ 31.50	$ 24.85
Feb-13	$ 31.82	$ 27.43
Mar-13	$ 33.12	$ 27.17
Apr-13	$ 37.08	$ 28.79
May-13	$ 38.16	$ 26.45
Jun-13	$ 38.13	$ 26.28
Jul-13	$ 43.81	$ 26.28
Aug-13	$ 37.24	$ 25.51
Sep-13	$ 35.46	$ 27.25
Oct-13	$ 34.22	$ 27.84
Nov-13	$ 32.86	$ 26.26
Dec-13	$ 42.96	$ 40.20
Jan-14	$ 39.86	$ 33.53
Feb-14	$ 60.02	$ 48.30
Mar-14	$ 41.64	$ 32.61
Apr-14	$ 40.58	$ 32.29
May-14	$ 41.33	$ 30.49
Jun-14	$ 44.94	$ 32.68
Jul-14	$ 45.81	$ 32.08
Aug-14	$ 41.34	$ 32.13
Sep-14	$ 40.70	$ 32.09
Oct-14	$ 38.20	$ 31.02
Nov-14	$ 37.95	$ 33.18
Nov-14	$ 37.95	$ 33.18
Dec-14	$ 30.74	$ 24.47
Jan-15	$ 25.94	$ 24.05
Feb-15	$ 23.97	$ 21.21
Mar-15	$ 24.79	$ 21.68
Apr-15	$ 24.01	$ 21.17

	On-Peak	Off-Peak
May-15	$ 23.75	$ 20.78
Jun-15	$ 31.50	$ 21.03
Jul-15	$ 36.25	$ 24.46
Aug-15	$ 35.17	$ 24.18
Sep-15	$ 30.06	$ 23.81
Oct-15	$ 26.98	$ 22.46
Nov-15	$ 22.75	$ 20.51
Dec-15	$ 22.28	$ 19.28
Jan-16	$ 21.16	$ 19.68
Feb-16	$ 18.67	$ 17.24
Mar-16	$ 17.09	$ 14.78
Apr-16	$ 18.96	$ 16.33
May-16	$ 18.61	$ 15.40
Jun-16	$ 31.79	$ 18.95
Jul-16	$ 43.80	$ 22.72
Aug-16	$ 35.37	$ 22.89
Sep-16	$ 26.66	$ 22.30
Oct-16	$ 26.41	$ 22.99
Nov-16	$ 19.62	$ 17.81
Dec-16	$ 29.04	$ 26.08
Jan-17	$ 27.30	$ 24.70
Feb-17	$ 27.76	$ 20.62
Mar-17	$ 19.58	$ 19.31
Apr-17	$ 29.48	$ 23.85
May-17	$ 28.15	$ 23.12
Jun-17	$ 49.48	$ 27.30
Jul-17	$ 39.66	$ 24.53
Aug-17	$ 62.54	$ 27.83
Sep-17	$ 41.83	$ 27.02
Oct-17	$ 38.25	$ 24.41
Nov-17	$ 27.85	$ 24.16
Dec-17	$ 26.58	$ 24.49
Jan-18	$ 26.90	$ 25.35

9.0 Summary Memo on Updated Results
March 12, 2018

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MEMORANDUM

DATE:	**MARCH 12, 2018**	**PROJECT:**	P.845
TO:	Kevin Davidson		
FROM:	Patrick Bowman Melissa Davies		
SUBJECT:	March 2018 Update to November 2017 report to the Hualapai Tribal Utilities Authority (HTUA) Board		

Pursuant to our discussion of March 9, 2018, I have attached a presentation intended for your Board meeting of March 15, 2018.

This memo sets out an overview for your information, in preparing for the Board meeting. The potential impacts of serving a large future water pumping load and Grand Canyon West will be addressed in a future memo.

InterGroup Consultants was retained by the Hualapai Tribal Utility Authority ("HTUA"), an entity of the Hualapai Tribe (the "Tribe"), to complete a "Cost of Service Study" to assist the Tribe in advancing the objective to provide electric service directly to its members.

The study builds on feasibility work completed for the Tribe in 2007 and 2009 (prior to the HTUA creation), which concluded that a Hualapai owned and operated electrical utility in Peach Springs could not fully recover its costs without either increases to rates, or from a subsidy from either the rates charged to service Grand Canyon West loads or from Tribal resources. With such supports, the earlier studies concluded an HTUA could recover its costs. The studies were considered sufficiently favourable to proceed with establishing the HTUA to further explore the utility ownership.

The purpose of acquiring ownership and taking over direct management of the Peach Springs electrical service has been focused on 4 areas:

1. **Tribal Capacity:** The HTUA cites an interest in seeking to bolster its energy resource development and management capacity, not in a vacuum but in the service of a major, decades-long venture to increase its economic viability, self-determination and sustainability.

2. **Reliability:** Concerns that were highlighted in the 2007 and 2009 studies regarding the level of reliability received from the existing service provider, Mohave Electrical Cooperative (MEC). It was suggested that an HTUA may be able to better achieve a reliable system.

3. **Use of Federal Power Allocations:** The Tribe is in possession of valuable allocations of federal power from the Boulder Canyon Project and the Colorado River Storage Project, which are presently targeted to other uses, but could form the basis of a firm power supply to the Peach Springs area.

4. **Development of Additional Tribal Resources:** There are significant potential resources in the Peach Springs area, focused at this time on possible solar developments of various scales. It is expected that an HTUA may be better able to facilitate these developments than has been possible to date with MEC as the service provider.

The initial summary of Cost of Service to provide power to Peach Springs was provided to HTUA dated November 9, 2017 (Attachments A and B to this memo). This November report largely confirmed the findings of the earlier Tribe reports, specifically concluding that it was unlikely HTUA could acquire the Peach Springs assets and operate them at a cost that was equal to or lower than the present MEC service.

The November report specifically concluded that the costs to operate an HTUA would likely be on the order of $250,000 per year higher than the present cost of being served by MEC (37% rate increase), and that this could only be achieved by reaching a favourable agreement with MEC to acquire the assets on tribal lands for approximately $740,000 to be financed by an RUS 20 year loan at 3%. This report had certain identified limitations:

1) No detailed estimate was prepared of bulk power supply costs, assuming that MEC's existing cost structure for bulk power would be representative of the future costs to HTUA
2) No benefits of the federal power allocations were included in the calculations
3) One-time transfer costs were assumed to be limited, and to be readily absorbed into the year 1 administrative costs budget (total $150,000)
4) No other capital costs upon transfer were included, assumed to be readily absorbed into the year 1 asset replacement budget (total $155,000)

The November HTUA Board meeting requested that these assumptions be further explored.

As reviewed the in attached presentation, this work has now been completed. The focus has been on assessing the potential for supplies from WAPA (both existing federal allocations and new wholesale supplies plus transmission). To complete this work, interviews were conducted with the following individuals:

- Kevin Schaefer, WAPA (re: Boulder Canyon Project)
- Parker Wicks, WAPA (re: Colorado River Storage Project)
- John Steward, WAPA (re: WAPA transmission)
- John Paulsen, WAPA (re: WAPA wholesale power supplies)
- Rick Campos, MEC

The result of the discussions is confirmation that WAPA can provide HTUA with all power needs through the Round Valley substation. The costs of this service, including all power procured based on recent prices, is between $388,000 (if all federal allocation used for supply to Peach Springs) to $420,000 (if no federal allocations are used). This compares to the November report, which assumed $490,000 for power at Nelson substation.

The review also highlighted the issue that there is no existing means to deliver the above noted power to Nelson substation, for delivery to Peach Springs. This means HTUA is left with 3 options:

1) Develop an alternative path for bulk transmission to Peach Springs (e.g., 69 kV from Round Valley as the likely cheapest option, with options like tapping APS 500 kV being even higher cost). This was noted to be prohibitively expensive, even if funded by low cost RUS grants. The only way this approach would be feasible is if federal grants were available (various WAPA staff indicated discussions with Randy Manion at WAPA may be the best route to investigate if this is possible).

2) Use MEC supplies to supply to Peach Springs. This would not prove to be remotely feasible on cost reasons (as it leads to no power cost savings to justify the capital spending and operating costs that HTUA would need to incur). This MEC rate for large supplies at the 25 kV level is almost equal to the costs that all of Peach Springs is paying now, such that there would be no "savings" to pay for all of the required HTUA investment, operating costs, etc.

3) Work with MEC to develop a new (and untested) "O&M agreement" concept to mimic a wheeling rate on the MEC 69kV Round Valley to Nelson line. This would permit HTUA to acquire its own supplies at Round Valley, and use MEC's assets to deliver this power to Nelson. MEC was not averse to exploring this idea, but the complexity should not be underestimated – this would need to act similar to a wheeling rate, but could not be a formal wheeling rate without MEC running afoul of a large range of utility issue (like NERC jurisdiction). The rate would likely need to be approved by the ACC. Also, even if an agreement was reached with MEC, there would also be a cost to compensate AEPCO for use of the Round Valley substation (AEPCO owns that substation). There is no way at this time to estimate the cost to HTUA to wheel this power.

The review also highlighted that a series of new costs and considerations should be included in the feasibility report, many of which serve to add challenges to the overall economics:

- Under the WAPA supply scenario, HTUA would need to invest in its own wholesale metering infrastructure. This is likely on the order of $100k capital cost.

- MEC indicated that even under a "buy out" scenario for Peach Springs, it is not likely that MEC's meters could be sold to HTUA, as these have a proprietary system and MEC branding, etc. If this MEC assertion is true, there will be an added capital cost to HTUA to purchase and install up to 500 new meters (including about 30 that are the larger demand-capable meters). New meters will be much more costly than the earlier assumption that largely depreciated MEC meters could be purchased.

- The complexity of the above arrangements suggests HTUA would be challenged to absorb all needed transaction costs in the year 1 administrative budget (which was estimated at $150,000)

- A physical reconfiguration of the assets is required to complete an HTUA buy out, including MEC constructing a new MEC-owned connection between the Nelson substation and the line connecting to the Hualapai substation (for example, from Nelson sub to the normally open switch in Peach Springs). This cost would need to be rate based by MEC, and they would need to include this in their assessment of the sale and their case before the ACC. In practice, this is not an HTUA cost, but it serves to more severely limit any flexibility that MEC may have to dispose of assets at a low cost, without driving up rates for other remaining Cooperative customers.

The other useful information arising from the interviews is that HTUA cannot be expected to be in a position to materially leverage a favourable buyout price from MEC, since all dispositions would require RUS and ACC approval for MEC, and each body has strict constraints about the prices at which the assets can be disposed. We have assumed a $740,000 buy-out price, which remains our best estimate, but receiving an updated cost estimate from MEC for all assets (excluding meters) based on Net Book Value would help refine if this is an appropriate estimate.

As a result of the above, it should be assumed that the one-time buyout and capital costs for HTUA to get up and running may readily be twice the value originally estimated of $740,000. This means the loan value should likely be assumed to be closer to $1.5 million, and the annual costs of servicing the loan (at RUS rates over 20 years) is approximately $50,000 per year higher than assumed in the November report.

Combining the above,

- The only savings identified is a maximum of $100,000 for bulk power if all federal allocations are used, but this can only occur at the expense of the benefits that presently exist for this power – i.e., the sales to other utilities, and the MEC bill crediting arrangements, as well as losing the potential to use this power for GCW service.

- Absent federal power allocations, the only savings identified compared to the November report are a maximum of $70,000.

- Offsetting this potential savings is a need to compensate MEC for wheeling this power to Nelson sub (unknown cost), a likely need to compensate AEPCO for use of the Round Valley substation (unknown cost), plus $50,000 in identified added debt servicing costs compared to November memo assumptions.

Though not all values are available to fully update the quantified Cost of Service assessment, the result of the added investigations is likely neutral to adverse to the earlier analysis, such that the 37% rate increase (or $250,000 required subsidy) remains a reasonable projection, if not low. Further the risks of the scenario are now increased due to an assumption of a doubling of the debt required to undertake the exercise.

It is also important to emphasize that the above scenario provides for a change in ownership, but no physical changes that would be expected to lead to reliability improvements. Such improvements could only come at an additional cost.

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10.0 HTUA Cost of Service Supplement Presentation to HTUA Board

Cost of Service for HTUA Owned Distribution Utility

Supplemetary Findings– Peach Springs

Presented to Hualapai Tribal Utility Authority (HTUA) Board Members, Personnel and Guests

March 14, 2018

November draft – Peach Springs

- The November 15, 2017 Cost of Service draft concluded that a rate impact of up to 37% should be anticipated for the Peach Springs portion of the HTUA operations.
  - This could be mitigated by subsidy from other sources, such as the federal power allocations.
- The rate impact was equivalent to $250k in revenue shortfall.

Supplementary follow up since November

- November meeting reviewed Board concerns regarding certain simplifying assumptions:
  - Assuming bulk power costs equivalent to MEC's costs.
  - Did not quantify the potential benefits of the federal allocations.
  - Did not address assumed delivery methods.
- This has now been completed, focused on WAPA supplies.
- Review highlighted some potential for savings (limited).

Updated Conclusions

- Challenge to deal with bulk power delivery:

1. A new alternate path instead of MEC is prohibitively expensive (unless major federal subsidy – grant, not loan)
   - For example, new line to Round Valley or WAPA transmission, or to APS 500 kV
2. Purchasing from MEC's own supplies is not affordable
   - MEC large buyer rate is only slightly below the cost of retail supply (likely $800k if buy in bulk at Nelson sub – versus $830k for the sum of all accounts today).
3. There is no existing option to "wheel" own power over MEC system.
   - MEC indicates they may be willing to work towards "O&M agreement" that would be much like a wheeling rate, but no experience with this, no idea of cost, and would still need ACC approval.

What would the “wheeling” option entail?

- Buy power from WAPA (or equivalent)
- Cost to deliver power to Round Valley
  - $420k/year if all purchased from wholesale markets (via WAPA)
    - 3.8 cents/kW.h supply at current forward prices
    - 0.4 cents/kW.h transmission
    - 0.8 cents/kW.h services
    - Total – 5.0 cents/kW.h
  - November estimate assumed $490k for bulk power cost at Nelson (5.8 cents/kW.h).
  - $70k in savings compared to November, but must still pay for MEC “O&M agreement” (and AEPCO Round Valley sub)

Costs likely would be more unstable in future than the existing arrangement, since all purchases from short-term market – MEC buys in part from AEPCO from owned plants.

What if add in federal power allotments?

- Use all federal allotments to supply Peach Springs
- Buy remainder from WAPA (or equivalent)
- Cost to deliver power to Round Valley
  - $388k/year
    - 3.4 cents/kW.h supply
    - 0.4 cents/kW.h transmission
    - 0.8 cents/kW.h services
    - Total – 4.6 cents/kW.h
  - November estimate assumed $490k at Nelson (5.8 cents/kW.h).
  - $100k in savings compared to November, but must still pay for MEC "O&M agreement".
  - Also lose all benefits from the current (or alternative) uses of federal allocations, such as MEC Bill Credit, or possible use at GCW.

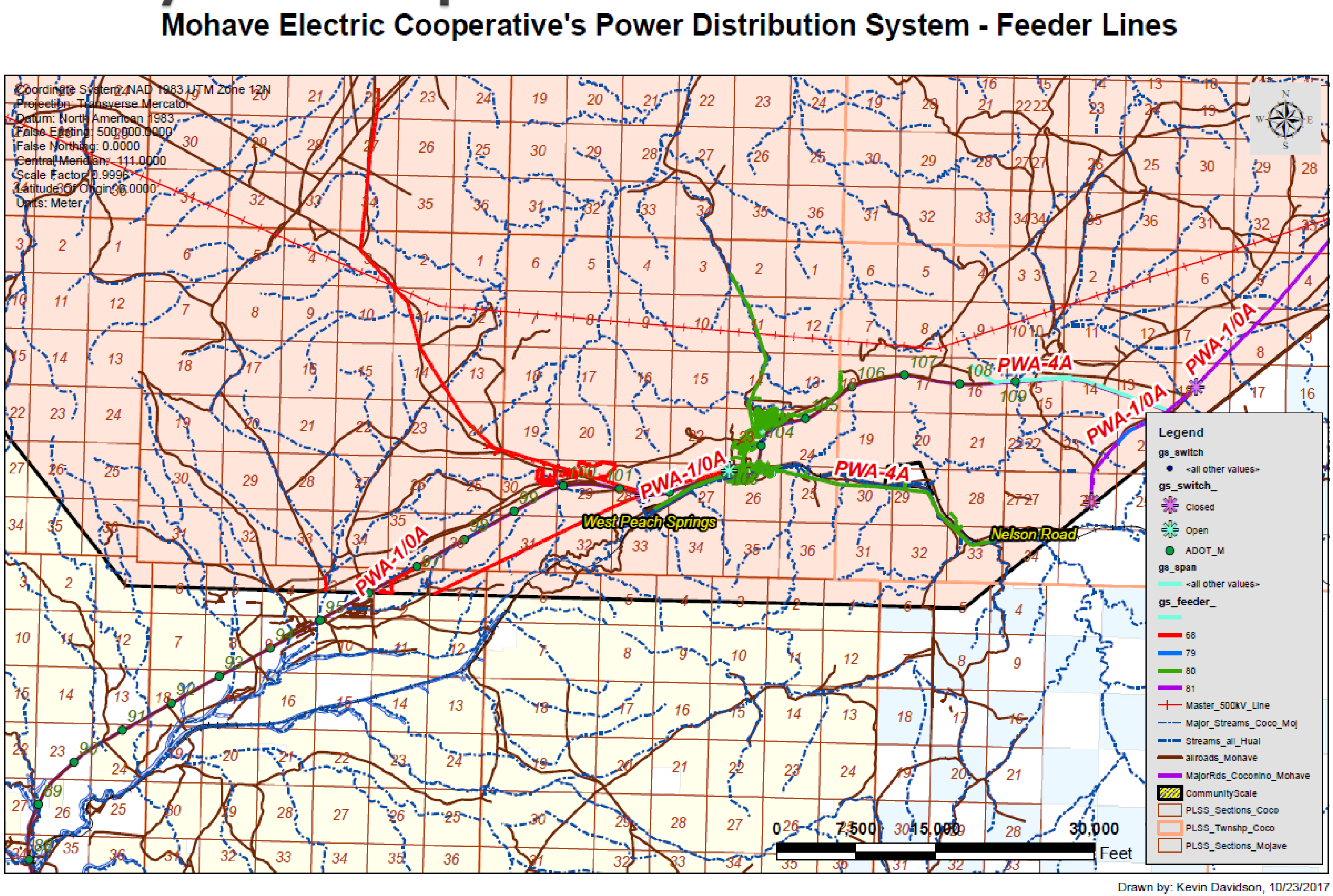
Other new information erodes business case

- WAPA indicates any wholesale purchases will require wholesale metering – up to $100k investment.
- MEC indicates would not expect retail meters could be transferred. Need new investment in approx. 500 meters (including 30 that are demand-capable).
- Transaction costs not previously estimated. Assuming new O&M agreement needed with MEC, and ACC approval, contracts with WAPA, etc. – should assume material one-time costs. (legal, accounting, etc).
- Had assumed $740k buyout cost would be main one-time investment. The new information could double that estimate.
  - Add $50k/year to costs
  - Increase initial debt to $1.5M.

Other new information

- MEC expects many assets backed by RUS loans – fixes prices at which assets can be sold (must recover full net book value)
- MEC would also require ACC approval for disposing of asset.
- MEC considers they need ACC approval to change their certificated area
  - Does not address HTUA requirements.

System reconfiguration would likely be required



System reconfiguration

- Would almost certainly need to move all HTUA Peach Springs loads to be served from a single feeder (under normal conditions)
  - Improves ability to meter
- MEC expects need for express feeder from west side (on the line from Hualapai sub) to Nelson sub (potentially 10 miles)
  - This cost will need to be rate based, and fit into overall economics of the sale
- Unlikely would prove economic for HTUA to take over feeder 81 (70 mile line)

Reliability

- Basic HTUA acquisition of the system is not expected to result in improvements in reliability.
- Reliability improvements can involve the following:
  - HTUA get grant for new supply line (e.g. Round Valley)
  - MEC continue with upgrades to supply from Hualapai sub (slowly progressing) to complete full dual supply
  - Incremental improvements are occurring anyway
    - Removing overhead 25 kV bus from Nelson sub to go pad mount/underground (dust)
    - Add circuit regulation and three phase circuit reactors to Nelson sub – still evaluating
    - Move Lhoist to 69 kV isolated supply

11.0 5 Year Forecast HTUA Revenue Requirement - Model Results

April, 2018

Forecast Annual Revenue Requirement

Peach Springs Annual Revenue Requirement		2019	2020	2021	2022	2023
Power Supply (Generation)		$ 342,026	$ 353,428	$ 365,270	$ 377,570	$ 390,347
Power Supply (Transmission)		$ 41,970	$ 41,970	$ 41,970	$ 41,970	$ 41,970
MEC/AEPCO "Wheeling" Round Valley		$ 10	$ 10	$ 11	$ 11	$ 11
OM&C - Distribution Related		$ 96,000	$ 98,880	$ 101,846	$ 104,902	$ 108,049
Administrative & General		$ 150,000	$ 154,500	$ 159,135	$ 163,909	$ 168,826
Asset Replacement		$ 155,000	$ 159,650	$ 164,440	$ 169,373	$ 174,454
Depreciation/Debt Service - Principal		$ 30,272	$ 31,331	$ 32,428	$ 33,563	$ 34,738
Finance Expense/Debt Service - Interest		$ 29,963	$ 28,903	$ 27,807	$ 26,672	$ 25,497
Other Expenses/Contingency/Reserves		$ -	$ -	$ -	$ -	$ -
Total Projected Costs		**$ 845,241**	**$ 868,673**	**$ 892,906**	**$ 917,969**	**$ 943,892**

	2019	2020	2021	2022	2023
Foregone Alternative Benefits from Federal Allocations	$ 48,000	$ 48,000	$ 48,000	$ 48,000	$ 48,000
Forecast Avoided Bills to MEC (at MEC Rates)	$ 713,511	$ 740,958	$ 769,459	$ 799,054	$ 829,786
HTUA Peach Springs Net Benefit	***($179,731)***	***($175,715)***	***($171,447)***	***($166,915)***	***($162,105)***
rate increase/(decrease) from HTUA Takeover	25.2%	23.7%	22.3%	20.9%	19.5%

in order to complete full neutrality to the MEC scenario
(includes both covering all HTUA costs and replacing benefits gained from lost sales of federal allocations to third parties)

Generation Summary

Peach Springs Load Forecast		2019	2020	2021	2022	2023
Forecast Sales MWh		8,134	8,195	8,257	8,319	8,382
Forecast Supply MWh (with losses)		8,378	8,441	8,504	8,569	8,634
Forecast Peak Monthly Capacity kW		2,338	2,358	2,379	2,399	2,420

G&T costs
With Federal Allocations

	2019	2020	2021	2022	2023
Generation Energy Costs - Federal Contracts	**$ 51,620**	**$ 52,764**	**$ 53,943**	**$ 55,157**	**$ 56,408**
Generation Capacity Costs - Federal Contracts	**$ 30,330**	**$ 30,330**	**$ 30,330**	**$ 30,330**	**$ 30,330**
Generation Costs - Additional	**$ 260,077**	**$ 270,333**	**$ 280,997**	**$ 292,083**	**$ 303,609**
Transmission Costs	**$ 41,970**	**$ 41,970**	**$ 41,970**	**$ 41,970**	**$ 41,970**

Without Federal Allocations

	2019	2020	2021	2022	2023
Generation Costs	**$ 374,319**	**$ 385,549**	**$ 397,115**	**$ 409,029**	**$ 421,300**
Transmission Costs	**$ 58,124**	**$ 58,124**	**$ 58,124**	**$ 58,124**	**$ 58,124**

12.0 Overview on Cost of Service Model

Overview of Forecast Cost of Service Model for Hualapai Tribal Utility Authority (HTUA)

This memo outlines the data provided and function in each tab of the Forecast Cost of Service model provided to the HTUA by InterGroup Consultants in April, 2018. The model has been prepared to analyze the cost estimates for an HTUA operation serving Peach Springs, AZ.

The model is intended to provide for comparison of the costs to serve the utility needs of the Hualapai under HTUA service, compared to the current service provider, Mohave Electric Cooperative (MEC).

One variable within the model is analysis on whether the costs of HTUA must be fully recovered from Peach Springs area load or whether some costs can be shared by HTUA also acting as a utility operator to Grand Canyon West (GCW), a new water pumping load, or potentially both. As a result, while this model focuses on cost estimates for Peach Springs, it provides the ability to consider a portion of HTUA's overhead and operating costs to be shared with a GCW and/or water pumping load.

The tabs are indexed by color, with RED tabs indicating where input variables are used (cells with pink shading are meant as input values), GREEN tabs representing the model output/results tabs and BLUE tabs indicating supporting data and analysis for the current inputs to the model. More detail on methods used for estimating values can be found in the HTUA Utility Cost Estimate Report dated December 11, 2017 (note due to updated information on power supply costs and some asset information from MEC, such as meters not being for sale will have adjusted cost estimates since the December 11, 2017 report in the model).

In order as provided in the excel model, detail for each tab included and functions:

1. **Overview** – provides a similar summary as the above as an introduction to the model.
2. **Forecast Inputs (RED tab)** – This tab summarizes the key model inputs. It has some links to other tabs, described in more detail in the explanations below where the inputs are used and contains the following data:
    a. Estimated Annual Operating costs, including Cost of Operation per year (OM&C – Distribution Related Costs – cell C6) and Administration and General Costs (Cell C7). These costs are adjusted for inflation for subsequent forecast years (per same tab cell C49) and used as inputs in the forecast Revenue Requirement in the 'Rev. Requirement Forecast' tab.
    b. Net Book Value Multiplier (cell C10), used in the 'Asset Replacement' tab to estimate the acquisition cost of MEC assets for the HTUA and described further in that section.

c. HTUA Financing Costs: Not inputs, initial capital investment to purchase Peach Springs assets (cell C13) calculated in the 'Asset Replacement' tab. Additional transaction and capitalized investment (cell C15) set equal to the asset purchase price representing legal costs, negotiations and one-time expert/professional fees required to set up utility, make supply arrangements, purchase bulk meters, etc. as may be required. Both values are summed and used in the 'P&I Breakdown' tab to forecast annual revenue requirement related costs (depreciation and finance).
d. Reserves/Contingency (cell C17) – currently set at zero, can add in annual amount which will increase revenue requirement to allow for rate smoothing and retained earnings to cover potential unforeseen costs.
e. Forecast Percentage Load Growth (cells C20 – G23) – forecast energy growth by customer class in forecast years. Currently set at 1% per year for all classes except large commercial as this is approximately equal to the average load growth from 2011 – 2016. Large Commercial class has not seen any sustained load growth in this time period. This growth is used in the 'Peach Springs payments MEC' tab to calculate forecast power supply requirements/costs and foregone revenue in the 'Rev. Requirement Forecast' tab.
f. Additional Load (Annual kWh) (cells C26 – G28) – optional scenario to add potential water pump load or other large commercial load (GCW). If populated, will populate the 'Peach Springs payments' tab to be included as additional power supply requirements/costs and additional foregone revenue in the 'Rev. Requirement Forecast' tab.
g. Net Profit/Benefit from Federal Allocations if not used for HTUA Services (cells C31 – G34) - used in the 'Rev. Requirement Forecast' tab depending on the option selected for the 'Are Federal Allocations Being Used?' scenario in the 'Forecast Inputs' tab (cell C57). Populates as foregone benefits if 'yes' is chosen (i.e. HTUA will use existing contracts to serve Peach Springs power requirements).
h. Asset Acquisition Annualized Costs – Annual Interest Rate (cell C37) and Loan Payback Years (Cell 38) currently based on known market rates for government utility loans and used in the 'P&I Breakdown' tab to calculate annual principal and interest payments for initial acquisition costs.
i. Annual Asset Replacement Costs – Distribution Asset Average Service Life (cell C43) based on average annual life of distribution assets currently (33.3 years), depreciation rate (cell C44) calculated from cell C43 – annual percentage of assetbase expected to be replaced (currently at 3%), inflation (from cell C49 below), used to calculate annual replacement costs for aging/damaged distribution asset base once purchased from MEC.
    i. 2017 Replacement Asset Valuation (cell C46) uses the 2007 Replacement Cost New (RCN) value from the 2007 Feasibility Study,

provided in the 'Asset Replacement' tab (cell F13) and inflates to 2017 for total replacement of asset base today.

   ii. The Annualized Replacement Costs (cell C47) calculated by multiplying cell C44 and C46 (i.e. total replacement spread out such that equal amount each year of the assets life). Used in the 'Rev. Requirement Forecast' tab (row 11) to estimate asset replacement costs, with an inflationary adjustment added in subsequent forecast years to represent rising costs to replace assets.

j. Inflation (cell C49) – currently at 3%, used in multiple tabs primarily for future forecast years where costs are expected to increase with time

k. Distribution Losses (cell C51) – currently at 3%, used in the 'Electricity Supply Cost Est' tabs for estimating electricity requirements for Peach Springs (as losses will occur in transport).

l. Payments to MEC/AEPCO to Wheel Round Valley to Peach Springs (cell C53) – estimate not provided as this is currently covered with service by MEC but is needed for proper cost estimates for power supply. When input, will populate 'Rev. Requirement Forecast' tab, adding the costs the HTUA is likely to incur.

m. Percentage of HTUA Operating Costs to Assign to GCW/New Pumping Load (cell C55) – Currently at 0. Option to reduce annual operating costs for Peach Springs specifically by splitting with potential GCW/new pumping load. Will adjust Administrative & General annual expense in the 'Rev. Requirement Forecast' tab accordingly.

n. Are Federal Allocations Being Used (Cell C57) – explained further in the explanation for 'Electricity Supply Cost Est No Federal' tab below. Input 'Yes' or 'No' into this tab for a scenario analysis where the HTUA can choose to purchase all wholesale power and retain existing benefit arrangements by foregoing contract power ("No") or use existing contract power arrangements and forego benefit arrangement money currently being received ("Yes"). Each option will adjust the 'Rev. Requirement Forecast' tab results (either adding costs for power supply costs or decreasing for foregone revenues respectively).

o. Wholesale Power Inputs: used in the 'Electricity Supply Cost Est' tabs explained further below.

   i. Estimated Parker Davis Wholesale Costs (cell C64) are estimated based on the Palo Verde wholesale costs provided February, 2018 by WAPA with adjustments.

   ii. WAPA Service Charge for Procurement (monthly) (cell C66) – monthly flat fee charged by WAPA for handling power delivery and transmission access. It is assumed HTUA would not hire someone to do this but would instead contract through WAPA who already offers these services.

iii. Reactive Supply and Voltage Control (cell C67) and Regulation and Frequency Response (cell C68) – per kW/month fees by WAPA for ancillary services from the 'WAPA 2018 Rate Sched' tab.
iv. BCP Energy Allocation (cells D71 – O72) – currently set equal to contract allotment. This type of contract does not guarantee MWh each month, instead it guarantees percentage of total energy generated per month (hydroelectric generation). Hualapai currently pays a percentage of total costs each month and in return receives the same percentage of generated power, which on average is the allotment amount. As such price per energy and price per capacity are estimates assuming total allotment is fulfilled. Used in the 'BCP' tab and the 'Electricity Supply Cost Est' tabs.
v. Parker Davis Transmission Tariff (cell C79) – from 'WAPA 2018 Rate Schedule' represents cost for wholesale capacity/kW/month for remaining capacity requirements for Peach Springs.

3. **Monthly Load Data (RED tab)** – Estimates the monthly peak capacity requirements for Peach Springs for the forecast years. Monthly energy (kWh/MWh) forecast by rate class was provided for Peach Springs by MEC for the 2016 year. Monthly capacity (kW) is calculated based on class energy sales by month, estimated load factors, distribution losses and system coincident factors.
    a. Using actual 2016 data, the forecast monthly energy and capacity requirements for Peach Springs is estimated using projected energy usage from the 'Peach Springs payments MEC' tab by customer class.
    b. This data is used to project capacity requirements for Peach Springs and power supply cost estimates (in the Electricity Supply Cost tabs) as well as forecast revenues.
4. **Baseline MEC Rates (RED tab)** – MEC rates as approved in the 2016 Rate Change Application currently being paid by Peach Springs customers, before adjusting for any applicable rate riders. Used as input in the 'Peach Springs payments MEC' tab to calculate total revenue.
5. **<u>Rev. Requirement Forecast (GREEN tab)</u>** – Summary tab that calculates forecast annual revenue requirement for the five forecast years 2019 – 2023 (annual costs) as well as forecast benefits (avoided bills to MEC at MEC rates) and foregone benefits (discontinuation of federal allocation funds) for HTUA owning and operating an electric utility. A summary of annual Generation costs and load forecast (in MWh with and without losses and monthly peak kW) are also included in this tab.
6. **P&I Breakdown (BLUE tab)** – From the 'Forecast Input tab' uses Annual Interest Rate (cell C37) and Loan Payback years (cell C38) as well as Total Capitalized Investment (cell C15) to calculate annual principal (depreciation) and interest (finance expense) per year as shown in the 'Revenue Requirement Forecast' tab, rows 12 and 13.
7. **Peach Springs payments MEC (BLUE tab)** – Peach Springs actual energy usage and calculated revenue by customer class based on MEC rates (including rate

riders) from the '1991 rates', '2012 rates', 'Baseline MEC rates' and 'MEC Rate Riders' tabs. For comparison purposes, the 2007 and 2009 Feasibility Study forecasts for the 2010 year is included. This data was provided by MEC.

   a. Used as a baseline year for forecast energy requirements (MWh), calculated monthly load (kW) and forecast revenue is the 2016 actual year, using 2017 approved rates (i.e. 2016 approved rates with the applicable rate rider).
   b. Forecast energy requirements for Peach Springs are based on forecast load growth for each customer class, currently set at 1% each year for all classes (except large commercial, which historically has not experienced much load growth) from the 'Forecast Inputs' tab (cells C20 to G23).
   c. Included in this tab is a scenario for new load (GCW, water pump load or other). Currently it is left blank but can be populated from the Additional Load section of the 'Forecast Inputs' tab (cells C26 to G27).

8. **Electricity Supply Cost Est 19 (BLUE tab)** – Calculates forecast energy and capacity costs (as well as service costs) for Peach Springs if HTUA was purchasing electricity directly as opposed to the current arrangement with MEC. Included are the following components:
   a. Monthly energy requirements (row 4), with distribution losses (row 5) as populated by THE 'Forecast Inputs' tab (cell C51 – currently set at 3%) as forecast in the 'Peach Springs payments MEC' tab is used to calculate forecast energy supply costs.
   b. Boulder Canyon Project Western Schedule related costs are forecast as per the 'BCP' tab and 'Hydro Comparison' tab for additional fees. Monthly MWh amounts are as per the 'Forecast Inputs' tab (row 72) as the entitlement from these contracts does not guarantee the full allotment of energy each month (based on water flows). The Energy Charge is from 'Forecast Inputs' tab (cell C75) based on the amount Hualapai pays for the energy allotment and assuming the full energy allotment is provided in that year (as seen in the 'BCP' tab).
   c. Boulder Canyon Project APA Schedule D2 related costs are forecast using the '2018 APA Charges' tab.
   d. Colorado River Storage Project, Western contract forecast costs are calculated based on the 'WAPA OCT 17 – Mar 18' tabs for winter and 'WAPA 2017 Apr-Sep' for summer.
   e. Remaining Peach Springs Energy Requirements (row 27) by month are calculated by deducting each contracts provided energy from total Peach Springs Energy Requirement. This remaining energy is forecast to be procured from wholesale contract arrangements, with the $/MWh value from the 'Forecast Inputs' tab (cell C64).
   f. Total Projected Energy Costs for 2019 are summed in row 32.
   g. For capacity costs, estimated monthly peak demand is calculated in the 'Monthly Load Data' tab. Capacity costs for each existing contract are calculated similarly to the energy portion explained above.

h. Remaining Peach Springs Capacity Requirements is calculated subtracting existing capacity contracts per month.
i. WAPA transmission contract costs to Round Valley costs are estimated using a rounded up 'peak' annual capacity reservation of 2,000 kW for 2019 as capacity reservations through WAPA are required in increments of 1,000 kW and the HTUA needs to ensure reliable power supply for customers (i.e. 2,000kW covers remaining Peach Springs Capacity Requirements in all months). The rate used is from 'Forecast Inputs' tab (cell C79), based on the Parker Davis Transmission Tariff (as provided in the 'WAPA 2018 Rate Sched' tab, cell E18).
j. Added WAPA Service Costs are from the 'Forecast Inputs' tab (cells C66 – C68) estimated from conversations with WAPA, monthly service charge for procurement and fees per kW of capacity supplied.

9. **Electricity Cost Supply Est 20 (BLUE tab)** – Similar to the 'Electricity Cost Supply 19' tab, except using forecast energy and capacity requirements based on the 2020 forecast year and with inflation factors for energy prices from the 'Forecast Inputs' tab (cell C49).
10. **Electricity Cost Supply Est 21 (BLUE tab)** – Similar to the 'Electricity Cost Supply 19' tab, except using forecast energy and capacity requirements based on the 2021 forecast year and with inflation factors for energy prices from the 'Forecast Inputs' tab (cell C49).
11. **Electricity Cost Supply Est 22 (BLUE tab)** – Similar to the 'Electricity Cost Supply 19' tab, except using forecast energy and capacity requirements based on the 2022 forecast year and with inflation factors for energy prices from the 'Forecast Inputs' tab (cell C49).
12. **Electricity Cost Supply Est 23 (BLUE tab)** – Similar to the 'Electricity Cost Supply 19' tab, except using forecast energy and capacity requirements based on the 2023 forecast year and with inflation factors for energy prices from the 'Forecast Inputs' tab (cell C49).
13. **Electricity Cost Supply Est No Federal (BLUE tab)** – Provided as an alternate scenario, in the 'Forecast Inputs' tab (cell C57) there is a 'yes' or 'no' option for whether or not the federal allocations are being used. If yes, power supply costs are forecast lower but there are foregone benefits in the federal allocation fees currently being collected by the HTUA for not using. If no, power supply costs are forecast higher but there is no foregone alternative benefit.
    a. This tab estimates the cost of purchasing all power through wholesale arrangements (i.e. continues collecting federal allocation fees and does not use existing contract arrangements). Whole energy prices are as per the 'Forecast Inputs' tab (cell C64) and capacity prices are from the 'Forecast Inputs' tab (cell C79). An Inflation adjustment is added for energy prices as per 'Forecast Inputs' tab (cell C49) for subsequent forecast years.

b. This tab is used instead of the other ‘Electricity Cost Supply Est’ tabs if ‘no’ is selected for the option to use federal allocations in the ‘Forecast Inputs’ tab (cell C57).

14. **Hydro Comparison (BLUE tab)** – Summary tab for current Peach Springs power supply contracts, with estimated power costs for the 2018 operating year. Additional Fees as reported for the BCP Western contracts are used in the ‘Electricity Cost Supply’ tabs.
15. **WAPA 2018 Rate Schedule (BLUE tab)** – 2018 Rate Schedule for WAPA services as provided by Kevin Schaefer at WAPA. Provided for comparison and used to forecast wholesale capacity charges (Schedule PD-FCT7 Parker Davis Transmission Service SLCA/IP rate of $1.46/kW/month as shown in rows 17 and 18)
16. **WAPA 2017 Apr-Sep (BLUE tab)** - Provided by HTUA, provides monthly capacity and energy allotment for the summer season WAPA Colorado River Storage Project (CRSP). Used as an input in the ‘Electricity Supply Cost Est.’ tabs.
17. **WAPA Oct 17 – Mar 18 (BLUE tab)** – Provided by HTUA, provides monthly capacity and energy allotment for the winter season WAPA Colorado River Storage Project (CRSP). Used as an input in the ‘Electricity Supply Cost Est.’ tabs.
18. **2018 APA Charges (BLUE tab)** – Estimation of monthly 2018 APA Charges for Hualapai including repayable advances and transitional costs. Used in the ‘Electricity Supply Cost Est.’ tabs to calculate BCP, APA Schedule D2 power supply costs for each forecast year.
19. **Hualapai (BLUE tab)** - Hualapai APA estimated cost and allotment (including annual invoice and energy and capacity costs) for 2018 and forecast for years 2019 – 2027, as provided by HTUA. Not used in model (costs provided again in ‘2018 APA Charges’ tab), provided for background.
20. **BCP (BLUE tab)** – Boulder Canyon Project Capacity and Energy Entitlement costs for the Hualapai Indian Tribe by month for Fiscal 2018 (October 2017 to September 2018) as provided by the HTUA. Used in the ‘Electricity Supply Cost Est.’ tabs to calculate annual BCP, Western Schedule power supply costs for each forecast year.
    a. BCP Energy Entitlement (MWh) each month is from the ‘Input Forecast’ tab (row 72), currently split up by month as per the fiscal 2018 entitlement (note this is not the actual amount supplied, just the estimated amount based on presumed water flows) of 710 MWh.
21. **1991 rates (BLUE tab)** – MEC rates from 1991 charged to Peach Springs and other MEC customers by customer class until the 2012 rate change (not including rate riders) . Not used in as an input in the model. Used as input in the ‘Peach Springs payments MEC’ tab to calculate total revenue.
22. **2012 rates (BLUE tab)** – MEC rates charged from 2012 – 2016 to Peach Springs and other MEC customers by customer class (not including rate riders). Used as input in the ‘Peach Springs payments MEC’ tab to calculate total revenue.
23. **MEC Rate Riders (BLUE tab)** – MEC rate riders applied to rates for the period 2007 to 2017, added/(subtracted) to energy rate by month. Used as input in the ‘Peach Springs payments MEC’ tab to calculate total revenue.

24. **HTUA – Asset Cost (BLUE tab)** – Breakdown of asset gross book value for Peach Springs specific assets owned and operated by MEC. Provided to the HTUA by MEC in December 2017. Used as an input in the 'Asset Replacement' tab to estimate net book value and asset acquisition cost.
25. **Asset Replacement (BLUE tab)** – Uses the 2007 Feasibility Study asset valuation data and 'HTUA – Asset Cost' tab to formulate a cost estimate for the acquisition value to purchase Peach Springs distribution assets from MEC.
    a. Gross book value costs from the 'HTUA – Asset Cost' tab are summed and counted by asset category in Columns K and L.
    b. Average Accumulated Depreciation is estimated using two methods for comparison: 1) Average Accumulated Depreciation percentage of MEC distribution plant assets as per the 2016 Rate Change Application (average of 29.27% depreciated), and 2) using the average percent depreciated applied in the 2007 Feasibility Study when assets were inspected by the then consultant.
        i. As its known there have been limited replacements to the Peach Springs asset base since the 2007 study and at that time the assets were very aged, this method was used in the model as more closely representing Peach Springs specific asset condition (average of 83.4% depreciated).
    c. Estimated Acquisition Value is calculated using the Original Cost Less Depreciation times a Multiplier in Column R. The Net Book Multiplier can be found in the 'Forecast Inputs' tab (Cell C10), currently at 150% and based on an average estimate in the 2007 study. This value will need to be negotiated with MEC in actuality and is subject to change.
    d. Note: Meters (Asset Code 370) are not available for purchase from MEC. As a result these asset costs are not included in the acquisition value estimate.

13.0 Forecast Cost of Service Model

(see embedded Excel file)

Appendix C: Community Scale Solar

Community – Scale Solar Feasibility Study

Hualapai Planning & Economic Development Department

Agenda

- ❖ Focus On Solar Energy Development
  - ❖ What Makes a Successful Energy Project
  - ❖ What Natural or Current Resources are Available
  - ❖ What Resources Need to be Addressed

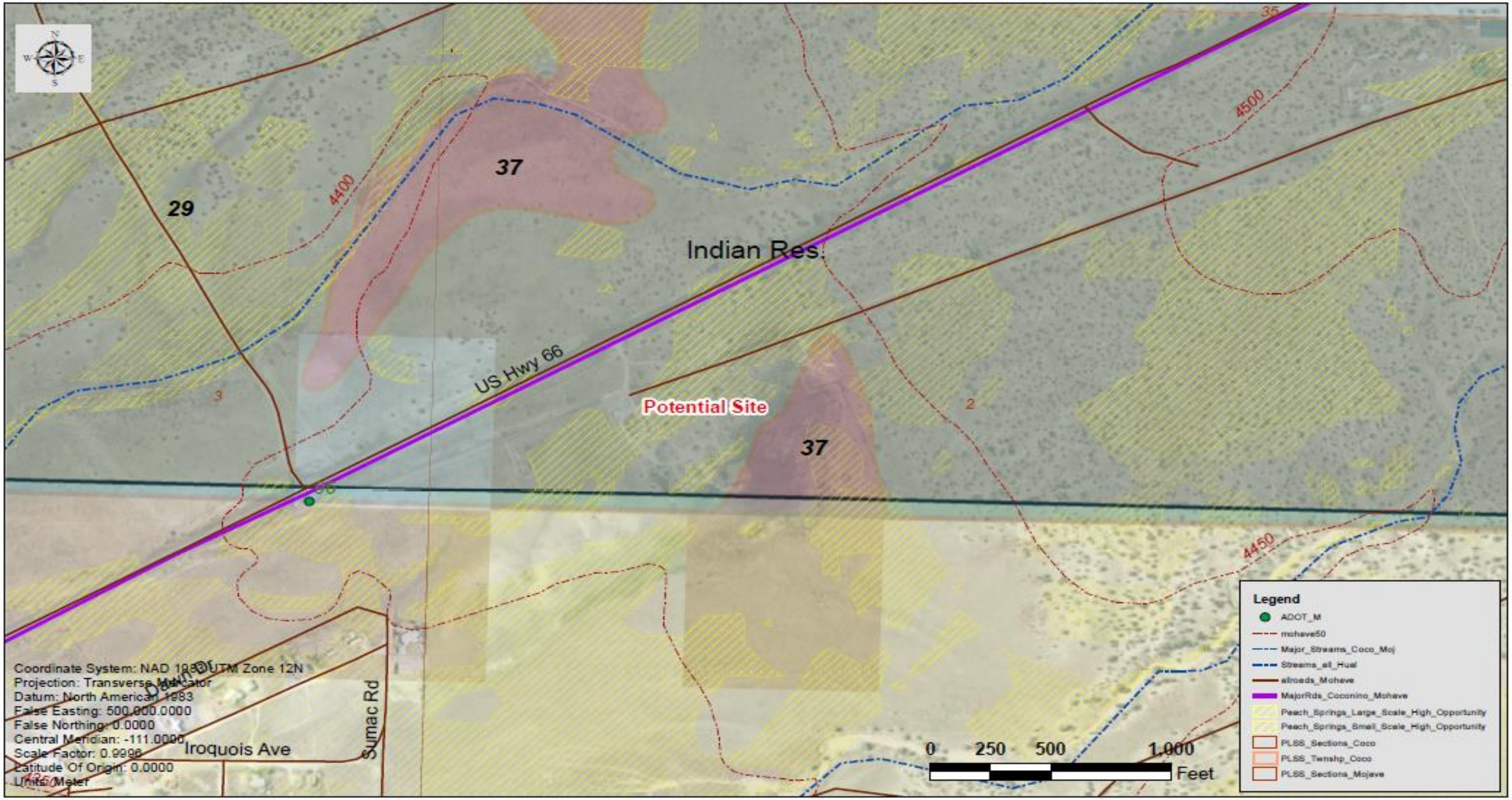
What Makes A Successful Solar Energy Project

- Lots of Sun – 8.5 kwh/day/m^2
- Adequate Land Space
- Transmission Access for Interconnection
- Cost of Project
- Power Purchase Agreement
- Culturally Appropriate Land
- Allocation of Benefits to Tribe

What Natural Resources Are Available

- Site 1 – Pump House
- Site 2 – Nelson
- Site 3 – Route 66

Pump House Solar Facility Site overlain on Topography, Soil Types & Solar Suitability

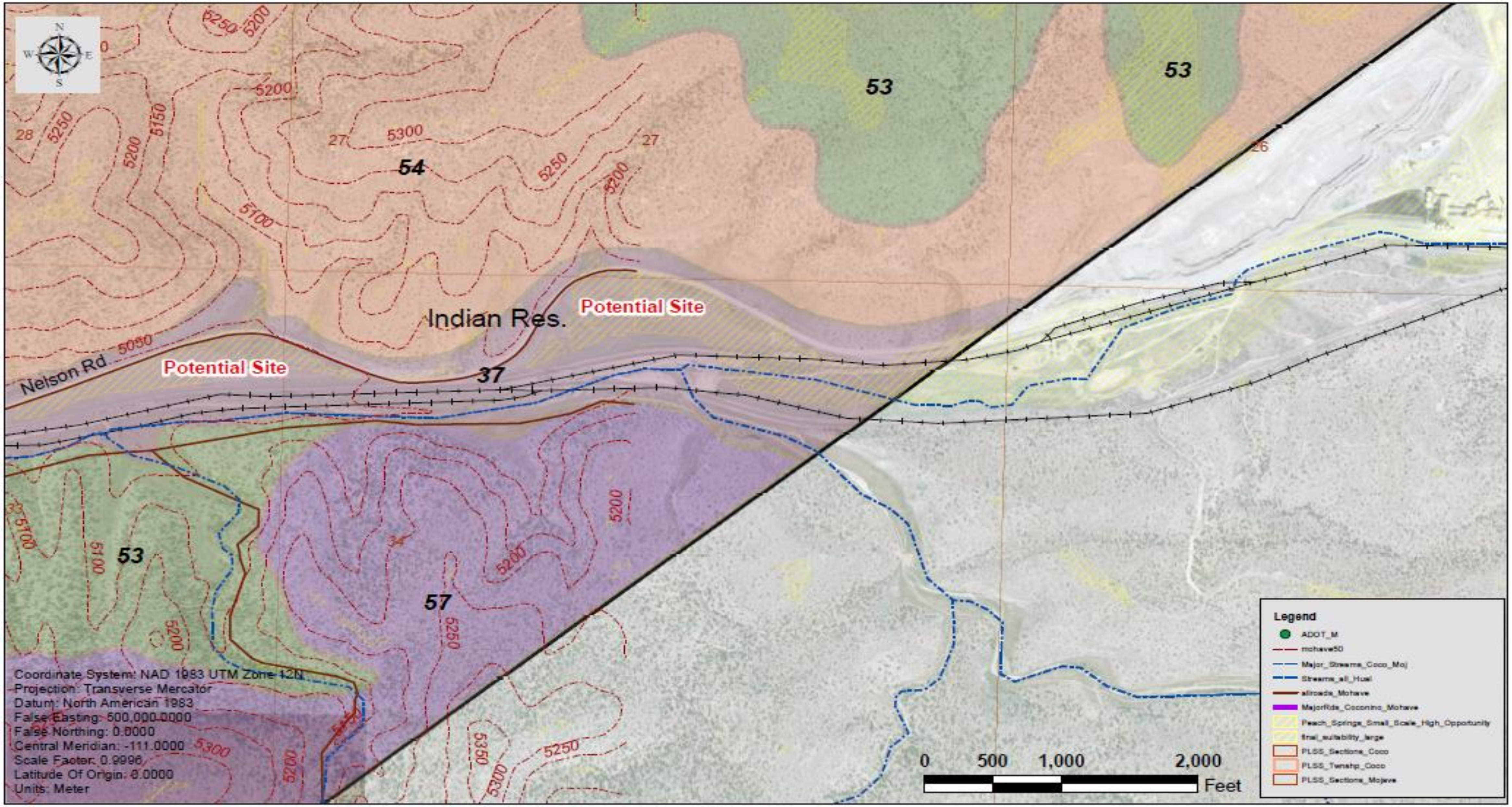


Drawn by: Kevin Davidson, 6/19/2017

Site 1 – Pump House

- ✔ Lots of Sun – 8.5 kwh/day/m^2
- ✔ Adequate Land Space
- ✘ Transmission Access for Interconnection
- ✘ Cost of Project
- ✘ Power Purchase Agreement
- ✘ Culturally Appropriate Land
- ✘ Allocation of Benefits to Tribe

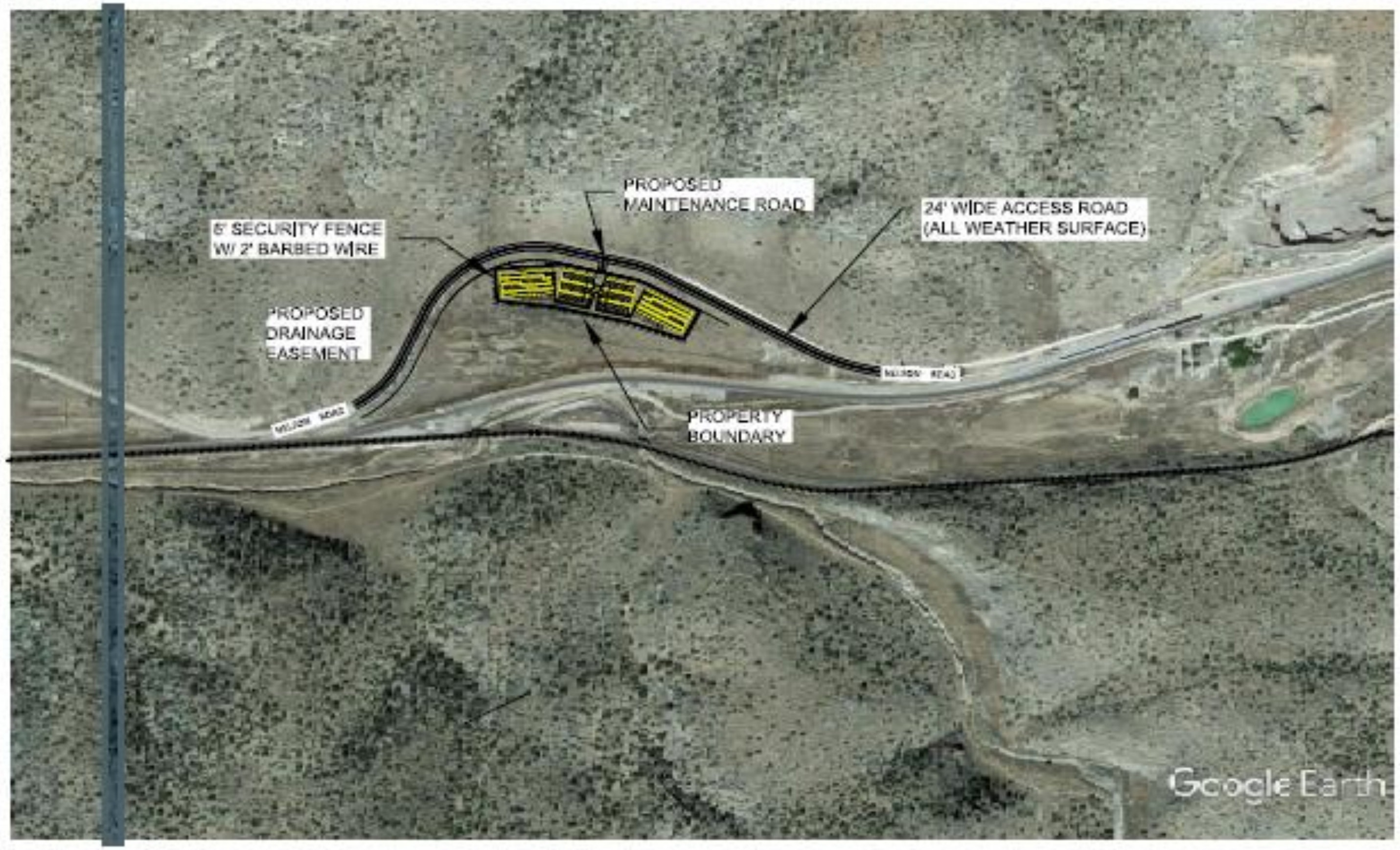
Nelson Road Solar Facility Site overlain on Topography, Soil Type & Solar Suitability



Drawn by: Kevin Davidson, 6/19/2017

Site 2 – Nelson

- ✔ Lots of Sun – 8.5 kwh/day/m^2
- ✔ Adequate Land Space
- ✔✔ Transmission Access for Interconnection
- ✔ Cost of Project
- ✕ Power Purchase Agreement
- ✔ Culturally Appropriate Land
- ✔✔ Allocation of Benefits to Tribe



PEACH SPRINGS SOLAR
PEACH SPRINGS, MOJAVE COUNTY, ARIZONA

PROJECT DEVELOPER
ROCK GAP, RITOCH-POWELL & ASSOCIATES, INC. AND ATEK GEOTECHNICAL

PROJECT OWNER/OPERATOR
HUALAPAI-HSK AND MOJAVE COUNTY POWER

PROJECT SITE DESCRIPTION
9.17 ± ACRE SITE
4.97 ± ACRE SOLAR ARRAY
LATITUDE 35°31.173' N (NE CORNER OF PROPOSED SITE)
LONGITUDE 113°27.193' W
ELEVATION 4704 FT. – 4720 FT.

PROJECT CLIMATIC CONDITIONS
RECORD HIGH TEMPERATURE 93° F
RECORD LOW TEMPERATURE 27° F

PROJECT DESIGN DATA
SNOW LOAD 5 PSF (ASSUMED)
WIND LOAD 90 MPH, EXPOSURE C
SEISMIC LOAD Ss=0.388g, S1=0.160g

PROJECT INTERCONNECTION
(TO BE DETERMINED)

PHOTOVOLTAIC (PV) SYSTEM PARAMETERS
(TO BE DETERMINED)

SOLAR PV PRODUCTION
(TO BE DETERMINED)

LEGEND
PROJECT BOUNDARY
PROPOSED AC ELEC. (TO PWCK)
PROPOSED AC ELEC. (TO PWCS)
EXISTING OVERHEAD LINE
PERIMETER FENCE
PROPOSED ACCESS ROAD
DRAINAGE FLOW (CONCENTRATION)
RAILROAD TRACKS

ROCK GAP

atek ENGINEERING CONSULTANTS

KEY MAP
SCALE: NTS

0 150 300 600
HORIZONTAL 1"=300'

DATE: Oct 16, 2017 FILE: C:\Users\...\PEACH SPRINGS SITE 2.dwg

811 Know what's below. Call before you dig.

NO.	DATE	BY	REVISION

% PRELIMINARY NOT FOR CONSTRUCTION

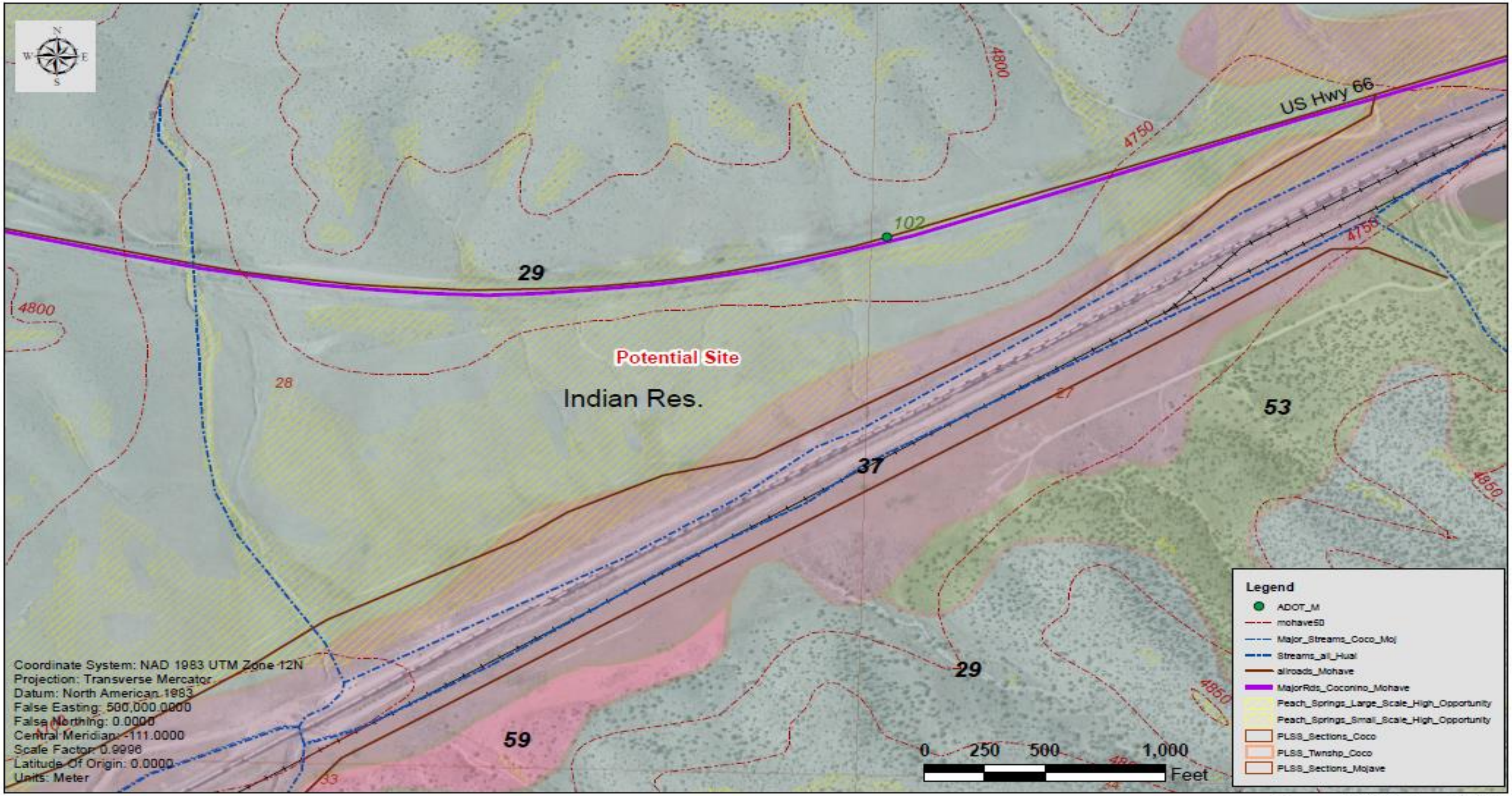
RPA RITOCH-POWELL & Associates
602-263-1177
www.ritochpowell.com

SITE DEVELOPMENT PLAN
PEACH SPRINGS SOLAR FEASIBILITY STUDY
SOLAR SITE LAYOUT
MOJAVE COUNTY PEACH SPRINGS, ARIZONA

JOB NO.:	213006
DESIGN BY:	RPA
DRAWN BY:	RPA
CHECKED:	SL
DATE:	2/7/13

DWG.
SHEET
OF 00

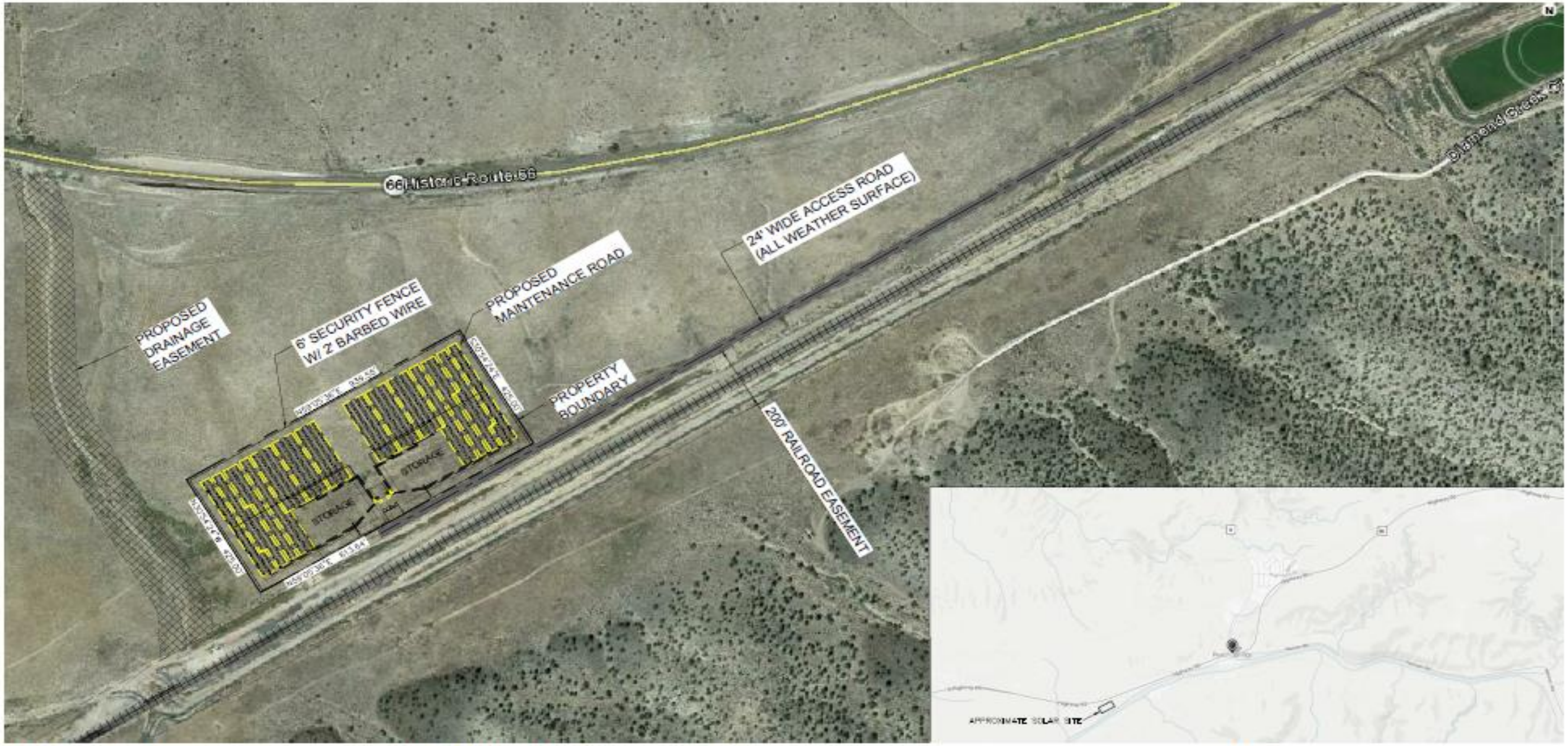
Route 66 Solar Facility Site overlain on Topography, Soil Type & Solar Suitability



Drawn by: Kevin Davidson, 6/19/2017

Site 3 – Route 66

- ✔ Lots of Sun – 8.5 kwh/day/m^2
- ✔ Adequate Land Space
- ✔ Transmission Access for Interconnection
- ✔ Cost of Project
- ✖ Power Purchase Agreement
- ? Culturally Appropriate Land
- ✔ Allocation of Benefits to Tribe



PEACH SPRINGS SOLAR
PEACH SPRINGS, MOJAVE COUNTY, ARIZONA

PROJECT DEVELOPER
ROCK GAP, RITOCH–POWELL & ASSOCIATES, INC. AND ATEK GEOTECHNICAL

PROJECT OWNER/OPERATOR
HUALAPAI–NSN AND MOJAVE COUNTY POWER

PROJECT SITE DESCRIPTION
9.17 ± ACRE SITE
4.97 ± ACRE SOLAR ARRAY
LATITUDE 35°31.173' N (NE CORNER OF PROPOSED SITE)
LONGITUDE 113°27.193' W
ELEVATION 4704 FT. – 4726 FT.

PROJECT CLIMATIC CONDITIONS
RECORD HIGH TEMPERATURE 93° F
RECORD LOW TEMPERATURE 27° F

PROJECT DESIGN DATA
SNOW LOAD 5 PSF (ASSUMED)
WIND LOAD 90 MPH, EXPOSURE C
SEISMIC LOAD Ss=0.388g, S1=0.160g

PROJECT INTERCONNECTION
(TO BE DETERMINED)

PHOTOVOLTAIC (PV) SYSTEM PARAMETERS
(TO BE DETERMINED)

SOLAR PV PRODUCTION
(TO BE DETERMINED)

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PROPOSED AC ELEC. (TO PVCS)
PROPOSED AC ELEC. (TO PVCS)
EXISTING OVERHEAD LINE
PERIMETER FENCE
PROPOSED ACCESS ROAD
DRAINAGE FLOW (CONCENTRATION)

KEY MAP
SCALE: NTS

ROCK GAP

atek ENGINEERING CONSULTANTS

811 Know what's below. Call before you dig.

NO.	DATE	BY	REVISION

RPA RITOCH-POWELL & Associates
602-263-1177
www.ritochpowell.com

PRELIMINARY NOT FOR CONSTRUCTION

SITE DEVELOPMENT PLAN
PEACH SPRINGS SOLAR FEASIBILITY STUDY
SOLAR SITE LAYOUT
MOJAVE COUNTY
PEACH SPRINGS, ARIZONA

JOB NO.:	213005
DESIGN BY:	RPA
DRAWN BY:	RPA
CHECKED:	SL
DATE:	2/7/13

DWG
SHEET 00

What Resources Need To Be Addressed

- Power Purchase Agreement
- Cost of Project
- Financial Feasibility
- Tribal Concerns

Power Purchase Agreement

- Terms the Buyer Will Purchase Energy from Solar Array
- Typical 25-Year Agreement
- Contains Escalation Causes
- Current PPA Purchaser is MEC
  - Verbally Agreed to a PPA
  - Restrict Array of Not to Exceed .5MW
  - No Escalation
  - Purchase Price $0.03 KW

Cost of Project

- Restricted .5 MW Array by MEC
  - Fixed Tilt Cost = $1,689,594.00
  - Power Production = 1,152,000 KWH
- Restricted .5 MW Array by MEC
  - Single Axis Tracking Cost = $1,869,147.00
  - Power Production = 1,587,500 KWH

Cost of Project

- Unrestricted 1 MW Array
  - Fixed Tilt Cost = $2,093,100.00
  - Power Production = 2,304,000 KWH
- Unrestricted 1 MW Array
  - Single Axis Tracking Cost = $2,335,590.00
  - Power Production = 3,175,000 KWH

Financial Feasibility of Restricted .5 MW Solar Array

	.5 MW Fixed
Production - KWH	1,152,000
Cost	$1,689,594.00
Revenue .03	$ 34,560.00
Revenue .06	$ 69,120.00
Payback .03	48.00 Years
Payback .06	24.40 Years
Revenue to Tribe .03	$ 0
Revenue to Tribe .06	$ 0

	.5 MW Track
Production - KWH	1,587,500
Cost	$1,869,147.00
Revenue .03	$ 47,625.00
Revenue .06	$ 95,250.00
Payback .03	39.00 Years
Payback .06	19.62 Years
Revenue to Tribe .03	$ 0
Revenue to Tribe .06	$ 552,450.00

Financial Feasibility of Unrestricted 1 MW Solar Array

	1 MW Fixed
Production - KWH	2,304,000
Cost	$2,093,100.00
Revenue .03	$ 69,120.00
Revenue .06	$ 138,240.00
Payback .03	30.30 Years
Payback .06	15.14 Years
DOE Grant .03	15.14 Years
DOE Grant .06	7.57 Years
Revenue to Tribe .03	$ 681,523.26
Revenue to Tribe .06	$1,204,761.60

	1 MW Track
Production - KWH	3,175,000
Cost	$2,335,590.00
Revenue .03	$ 95,250.00
Revenue .06	$ 190,500.00
Payback .03	24.5 Years
Payback .06	12.2 Years
DOE Grant .03	12.26 Years
DOE Grant .06	6.13 Years
Revenue to Tribe .03	$1,213,485.00
Revenue to Tribe .06	$1,797,367.50

Financial Feasibility – What-If PPA $0.075

	1 MW Fixed
Production - KWH	2,304,000
Cost	$2,093,100.00
PPA $0.75	$ 172,800.00
Payback	12.1 Years
Revenue to Tribe	$2,226,900.00

	1 MW Track
Production - KWH	3,175,000
Cost	$2,335,590.00
PPA $0.75	$ 238,125.00
Payback	9.8 Years
Revenue to Tribe	$3,619,500.00

ROCK GAP
engineering

Thank you !

Hualapai Planning & Economic Development Department

Appendix D: HTUA Presentation to Hualapai Council July 26, 2018

Hualapai Council and Hualapai Tribal Utility Authority Board Joint Meeting July 26, 2018

Todays Items for discussion
and
Direction from the Hualapai Council

Hualapai Tribal Utility Budget/Financial Forecast Scenarios

GCW Transmission Line Update

HTUA Governance Structure

Simplified HTUA Expense/Revenue model Scenarios

		Now	GCW	Breakeven
Revenue	unit			year 10
Peach Springs	KWH	8,200,000	8,200,000	8,200,000
Grand Canyon West Existing(besrt estimate)	KWH		4,000,000	4,000,000
Grand Canyon Wst Expansion	KWH			4,000,000
Additional load growth 1% yearly	KWH		122,000.00	1,220,000
Colorado River Pumping Load 1.5 MW @33% load factor	KWH		-	4,000,000
Total	KWH	8,200,000.00	12,322,000.00	21,420,000.00
Total Revenue @ 8.5ents KWH	0.085	$ 697,000	$ 1,047,370	$ 1,820,700
Expenses				
Costr of power ($37 MWH)	37	$ 303,400	$ 455,914	$ 792,540
Labor		780500	780500	780500
debt service(MEC assets 900K)		50000	50000	50000
Misc(Capital/IT/Phone/Office…)		225000	225000	225000
		$ 1,358,900	$ 1,511,414	$ 1,848,040
profit or loss		$ (661,900)	$ (464,044)	$ (27,340)

Simplified Expense Estimates of HTUA Details

I. Labor				
Position Description	Base Wage	Cost of benefits	Total Number Employee	Total cost for Position
		0.3		
General Manager	$ 125,000	$ 37,500	$ 1	$ 162,500
lineworker	$ 100,000	$ 30,000	$ 3	$ 390,000
Office Accountant/CASR	$ 60,000	$ 18,000	$ 1	$ 78,000
outside Consultants	$ 150,000		$ 1	$ 150,000
Total Payroll				$ 780,500
II Rolling Stock	Grant Potential?			
line Truck/digger	$ 250,000	1		$ 250,000
Bucket truck	$ 250,000	2		$ 500,000
Back Hoe	$ 150,000	1		$ 150,000
4X4	$ 60,000	2		$ 120,000
Total				$ 1,020,000
III. Building	Grant Potential?			
Peach Springs				$ 1,500,000
GCW				$ 500,000
				$ 2,000,000

GCW Transmission Line Update

Ownership triggers operational responsibility

ROW Update

Environmental/Cultural /BLM

Estimated cost

Who will Pay

Planning for Pumping Load

Leveraging HTUA Expertise

GCW Transmission Line Update

<u>Ownership triggers operational responsibility</u>

ROW Update

Environmental/Cultural /BLM

Power Line Survey on June 21, 2018

UniSource substation on Pierce Ferry Road (TR1)

Power line staking proceeds north and east (TR1 to TR3)

BLM preferred route for power line at MP 26 on Antares (TR3)

Looking west along power line staking (TR3 to TR2)

Power Line Survey on June 21, 2018

Route survey near MP 25 on Antares Road (TR4)

Power line staked over 200' east of Tenney Ranch Rd (TR5)

Potential cultural sites on cliff face (TR6)

Looking at toe of slope in center of Section 34 (TR6)

Power Line Survey on June 21, 2018


Begin ascent on Hells Canyon (TR6)


Near midway on Hells Canyon (TR6)


Midway on Hells Canyon (TR6)


Nearing top of Hells Canyon (TR7)

Power Line Survey on June 21, 2018

Top of Hells Canyon (TR7)

Top of Hells Canyon (TR7)

Trees along roadway and range fire prevention sign (TR8)

Honey Moon tank about ½ mile north of route (TR9)

Estimated cost:

12-15 million less 2 million grant
@13 million yearly payment 1.6 million –
21 million total 8 million in interest
Rate 3.5%--30 years

Who will Pay:

Hualapai General Fund
GCW Fund
Lender will require certain loan covenants and proof of ability to pay loan back—pledged revenue?

Planning for Pumping Load

Round Valley-Peach Springs-GCW-Dolan Springs Loop---Enhanced Reliability

Developing internal expertise now

Same disiplines can be used to operate pumping system

Leveraging HTUA

Plant contractor will make 15 to 20 %or 1.3 to 2millon

Self build –use 750 k for staff and 1.25 million for rolling stock that Ztribe will then own

HTUA Governance Structure

Ability to waive sovereign immunity with council approval

Ability to make quick financial decisions 1k-25ok with Board approval

Ability to manage independent accounting
- Receive cash payment
- Incur debt?

Long range financial commitments
- Purchase power agreements
- Rolling stock ---25-300k
- Capital improvements 5k-multi-million projects

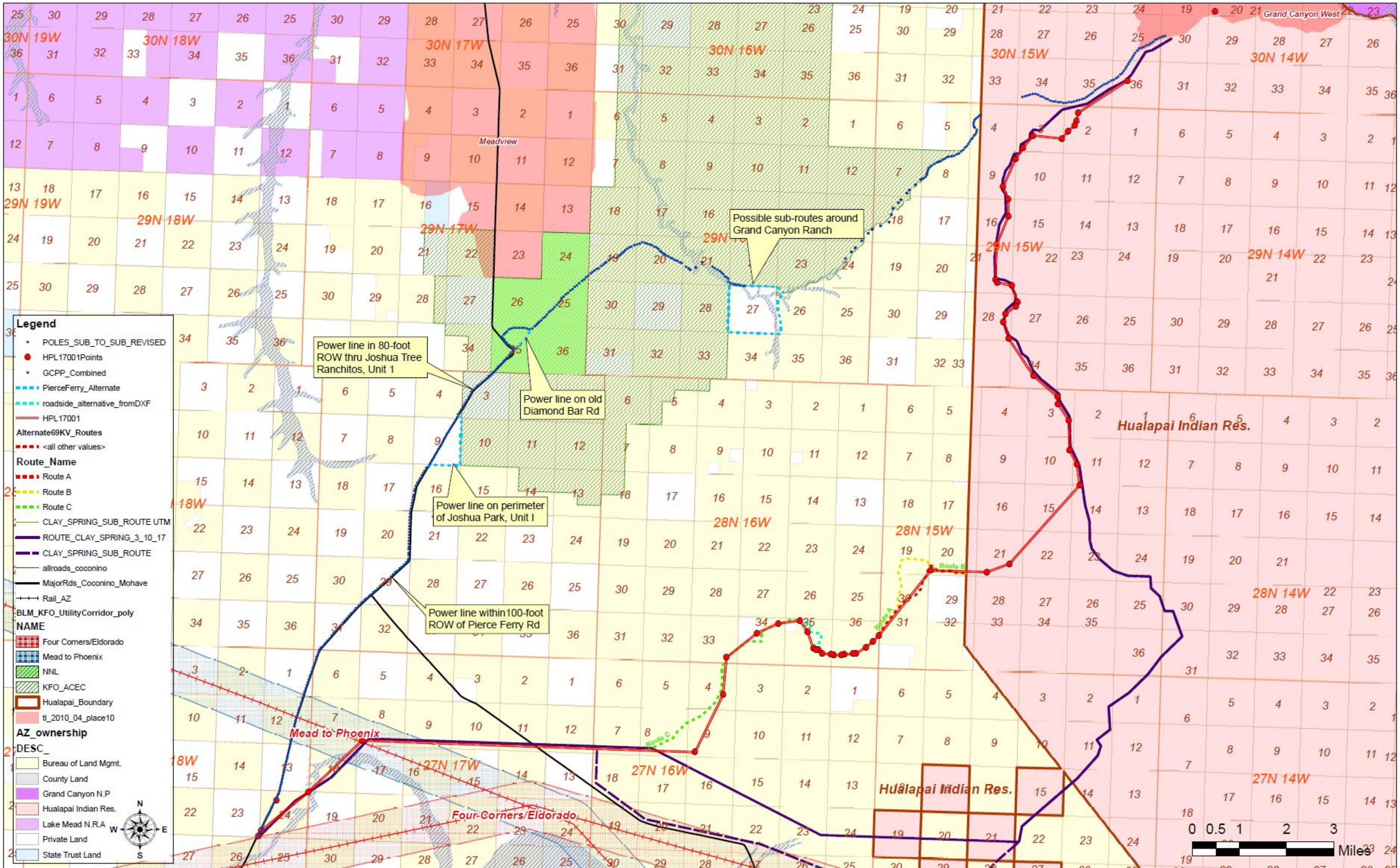
Non-Hualapai Management managing Hualapai employees
- Typically high paying salaries -----line workers 100k plus
- Unique work hours-policies
  - Call out
  - Standby

Most successful Tribal Utilities have similar governance structures that allow for above

Discussion

Appendix E: Alternate Power Line Routes to Grand Canyon West

69 KV Powerline Routes to Grand Canyon West



Prepared by Kevin Davidson, 8/8/2018