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Feasibility of Renewable Energy Development at Arch Hurley Conservancy District


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Illustration:

Front Cover – Views of Conchas Canal in the Arch Hurley Conservancy District near Tucumcari, New Mexico.

EXECUTIVE SUMMARY

Summary
The Arch Hurley Conservancy District (or AHCD) utilizes a system of canals and laterals to provide water for farmland around the Tucumcari area. While the system has served its purpose well since its creation in 1938, the long-term effectiveness of the project has suffered due to drought conditions, evaporation from the open-air Conchas Canal, and infiltration. This considerable drop in available water necessitates change for long-term sustainability.

This NMSBA project worked with AHCD to consider the feasibility of developing energy-generating technologies to raise funds for canal improvements. Renewable energy sources were screened for their feasibility. This involved an analysis of revenues, costs, and socio/political factors among other measures. After the pre-screening, AHCD chose Solar and Wind as the energy options for consideration. A conceptual development plan was devised to determine revenue from the project.

To begin this process, the LANL team looked at available siting options on land within AHCD control. Once a site with the best renewable energy potential was chosen, a plan that included three wind turbines with a total capacity of 7,500 kW coupled with 2,000 kW of capacity from photovoltaic (PV) solar cells was assessed. The feasibility analysis for the project estimated revenues for AHCD of between $1.2 and $3.9 million over 20 years. This revenue stream would only allow for minimal piping or lining of the main canal. Therefore, possible improvements to laterals within the AHCD are advised as a more cost effective use of revenue.

Pre-screening of Available Technologies
Four possible electricity producing technologies were considered for this project. These technologies were: Wind, Low-Head Hydro, Solar Photovoltaic, and Natural Gas Microturbine. Each of these technologies was defined based on a standard production capacity to allow ease of scaling and decision analysis scoring using the program Criterium Decision Plus. The weights used for the criteria and scoring of the alternatives were then combined to create the final results of the decision model. The decision score was found by computing the weighted sum of the scores of each alternative. The sum of an alternative's scores against all the sub-criteria multiplied by their appropriate weights was the total score.

Three different perspectives were used to set the weights. Results were then compared under the perspectives to see if the ranking of technologies differs. The results for the different energy technologies using each of the four weighting schemes for top-level criteria (Equal, LANL, AHCD, and Environmentalist) were compiled for AHCD to review. Upon consultation with AHCD, the project decided to move forward with Solar Photovoltaics and Wind Turbines as the preferred renewable energy sources.

Siting Options
When considering possible sites, the most important variables are the availability of the required resources, land topography, and any permitting or socio/political issues that could create "show-stoppers." Initially, a number of sites were considered on T4 Cattle Company land near the Conchas Canal. These areas were deemed insufficient after consulting with AHCD. Upon further discussion with Arch Hurley, three main siting locations were analyzed (see Figure 1).

The first is the "Y Site" on Bureau of Reclamation property near what is called the Y Substation. Located at a split in the Conchas Canal, this location is beneficial in that it is close to an electrical substation. However, this land does not have a consistent level and is below the floodplain. Considering the closeness of the land to the canal and its periodic flooding, this site is unsuitable.

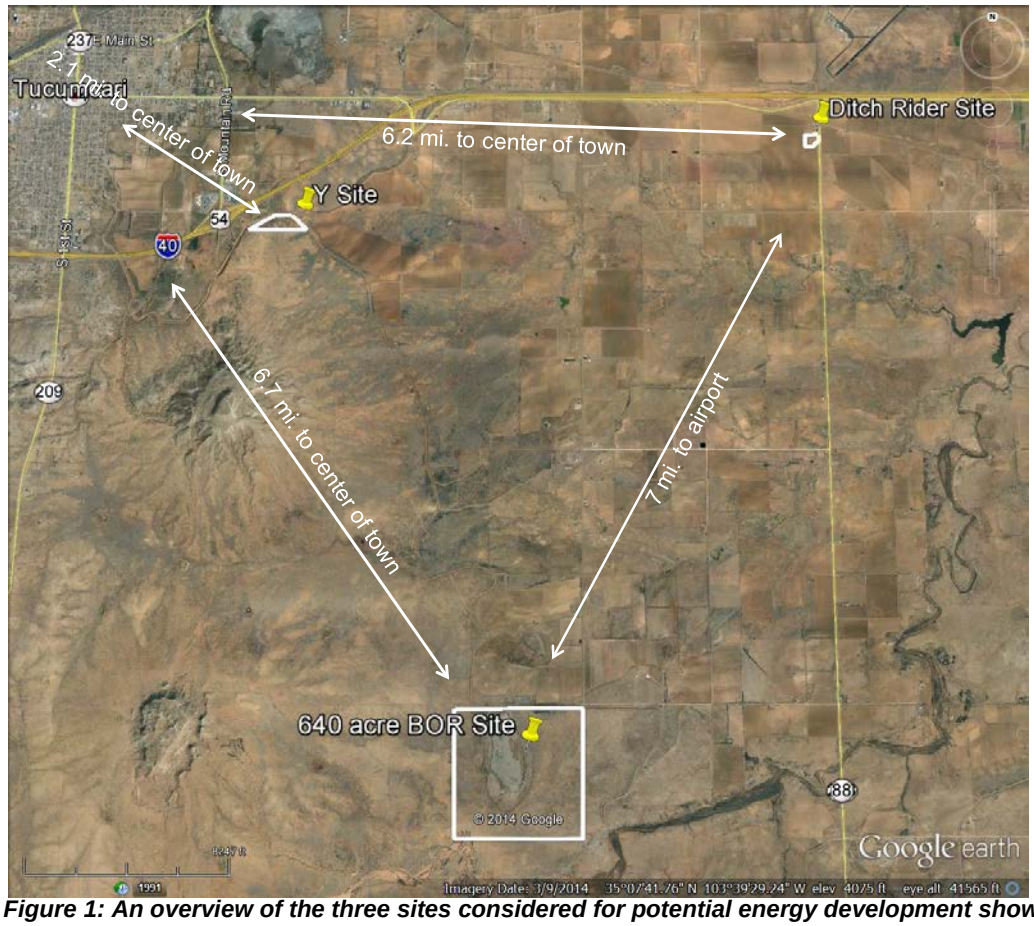

Figure 1: An overview of the three sites considered for potential energy development shows the positions relative to the town of Tucumcari.

The second siting option is known as the "Ditch Rider Site." It is a flat, ten-acre parcel of land with a 4.4 mile distance to the Y Substation. The biggest drawback for the Ditch Rider site is its proximity to I-40 and the Tucumcari Airport. Wind turbines are ruled out for this area and there are concerns about a solar array interfering with nearby flight patterns. Nevertheless, the site could be considered as a location for solar energy resources in the future.

The last location (the "BOR Site") is approximately seven miles south of the Tucumcari airport and consists of 640 acres of land. Though this land is not directly under Arch Hurley's authority, the Bureau allows for usage and leasing of the land to other parties as with the other two sites. While there are 640 acres available, the presence of a depressed playa that is vulnerable to flooding towards the middle of the property leaves only half of land suitable for electricity generation purposes. This site was chosen as the optimal space for renewable energy development.

Analysis of Renewable Energy

Figure 2 provides an overview of the proposed wind and solar development. The entire developable area has over 200 acres in a northern direction, offering construction grade terrain with 2 percent slope or less. At full project build-out, six wind turbines and a 40 acre solar array could be installed. In the feasibility analysis it was assumed that Phase 1 would provide a maximum AC power rating of 7,500 kW using three wind turbines and Phase 2 would have a maximum AC power rating of 10,580 kW by adding solar PV. In the figure, turbines numbered 1 to 3 would be installed first, and then solar arrays numbered 4. Remaining items marked *F* are for possible future development. Grid connection consists of a 69 kV tie-in station *STA 1*, connecting to a 115-69 kV step up station located 2.7 miles west of the site.

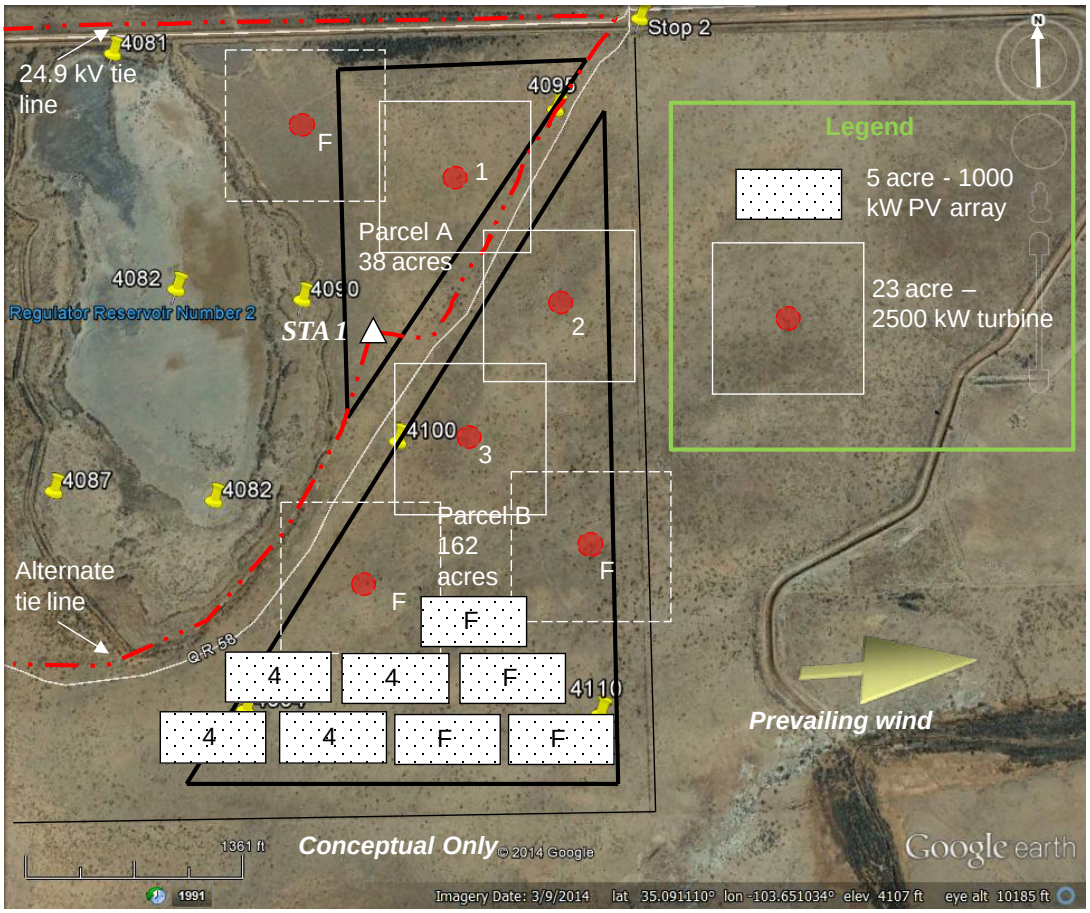

Figure 2: A conceptual plan to develop 10,580kW of electricity capacity using two phases is shown here. The red dots labeled "1, 2, and 3" in the squares show wind turbine locations built in phase 1, and rectangles labeled "4"are PV solar arrays for phase 2. Boxes labeled "F" are future activities.

A roll-up of key financial results from this analysis is shown in Table 1, tabulated as 20-year cumulative values. A possible interconnection within Farmers Electric Cooperative's (FEC's) system presents a potential hurdle, in terms of receiving a competitive buyback rate. The analysis assumes a $45 per MWh power purchase agreement is negotiated (4.5 cents per kWh). A developer can economically produce power assuming 4.5 percent cost-of-money, all State and Federal tax benefits accrued, and royalty payment of 3 percent to AHCD. About $1.3M is available to AHCD over twenty years, or about $65k per year on average

Significant unknowns are 1) FEC's ability to pay competitive buyback rates and 2) the near-term cost of solar cells which are dropping due to strong Chinese competition. If PV cell prices drop an additional 50 percent (which is possible in five to seven years), then the PPA required to achieve a 4.5 percent internal rate of return (IRR) drops to $40 per MWh. Royalty payment to AHCD also drops somewhat. Generally, utilities in New Mexico will be reluctant to pay more than retail energy rates for renewable power. FEC's current retail tariff rates are 8 cents per kWh for large "Power Service," 7.3 cents for Commercial service and 12 cents for Residential service. It is possible that more revenues could be generated for AHCD.

TABLE 1
Financial Results for BOR Site Development, over 20 Years

Construction Cost	Operating Expense	PPA $/MWh	Net Tax Expense	Revenue	Net Revenue to AHCD
($18,554,000)	($16,172,820)	45	($4,011,480)	$35,085,180	$1,290,610

A best-case value might be ashigh as $3.9M over twenty years if several key feasibility factors were improved. First, a more intensive use of the BOR Site with a tighter turbine layout might increase electricity capacity by up to 50 percent. Second, it is possible that the typical three percent energy royalty and $150 per acre lease fee could be doubled, although this is rare in New Mexico. If these favorable factors were applied, the revenue stream to AHCD would $3.9M ($1.3M × 1.5 × 2).

Canal Piping and Conclusions

The Los Alamos team conducted rough calculations to size a pipe adequate for 300 cubic feet per second (cfs) of flow in the 1-foot per 1000-foot gradient of the Main Canal. The model indicates an area of 129 square feet in a rectangular box would be needed to handle the flow. This translates to a 13-foot diameter pipe, or dual ten-foot pipes each having 150 cfs in flow. Such pipes are very expensive and generally not used in canal systems. A ten-foot pipe would be less expensive but comes at the expense of a much smaller flow. An alternative to the pipeline is to line the main canal with concrete to prevent infiltration. The cost per mile for lining the main canal would be $2.6M per mile and lining the laterals would cost $270k per mile.

The renewable energy project is estimated to return about $1.3M to AHCD over 20 years. This value is too small to finance a main canal lining or pipeline project, which would cost millions of dollars per mile. For a 20-year loan at seven percent interest, the $2.6M per mile canal lining cost would require payments of $242k per year. The $65k annual revenues would cover only about one-third of a mile of lining. In the unlikely event that the best case revenue stream of $3.9M could be obtained, the $195k/y available could support about one mile of main canal lining. In contrast, the revenue stream appears adequate to support improvements in the lateral canals, since the costs per section is the same order of magnitude as the average annual revenue stream, i.e., tens of thousands of dollars. Since the most cost-effective acre-foot savings is from lateral lining and such projects are tractable in terms of revenue flow, it is recommended that prioritized projects of lateral improvements be pursued, perhaps via the NMSBA program.

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I. INTRODUCTION

The Tucumcari Project has about 41,000 acres of irrigable land.[1] The Conchas Reservoir supplies water to the 84-mile Conchas Canal and its branch, the 26-mile Hudson Canal, which together supply water to a 172-mile distribution system. See Figure 1. The Conchas Canal has an initial capacity of 700 cubic feet per second (cfs), and includes 31 siphons totaling 21,921 feet

Figure 1: Conchas Canal has open ditch with periodic gates.

[1] This paragraph of information comes from the Bureau of Reclamation website, http://www.usbr.gov/projects/Project.jsp?proj_Name=Tucumcari%20Project.

and five tunnels with a total length of 30,140 feet. The tunnels are eleven feet in diameter. The Hudson Canal has one siphon of 3,200 feet in length. The construction of the irrigation system began in 1940 and was operational in 1950. Additional improvements occurred from 1961 to 1976. Crops grown in the Project generally support livestock operations and include alfalfa hay, alfalfa seed, grain sorghum, cotton, and broom corn. The Arch Hurley Conservancy District was established in 1938 with an initial repayment contract. Pumps were installed at the Conchas Dam in 1953.

The overall goal of the AHCD is long-term in nature: providing a system of water delivery that can support farming now and for the next generation. This can be done by targeting sections of the main canal and laterals for engineering to support an improvement in water delivery efficiency. Grants and renewable energy revenues perhaps can be pooled to support sequential pipeline installation or canal improvements over time.

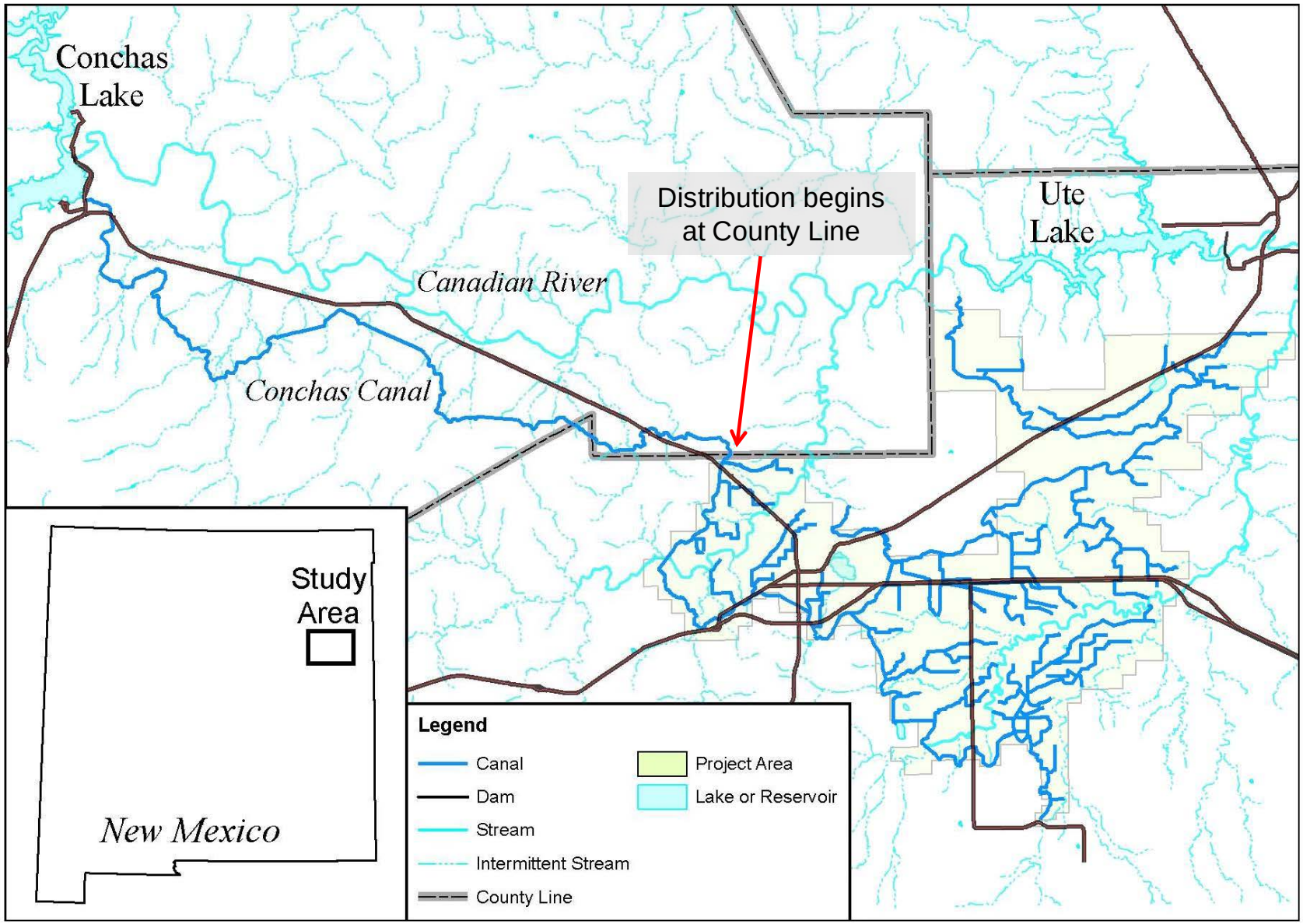
There has been past work on pipeline planning for the main canal. A conceptual plan created in 2000 to 2001 that had the support of Bureau of Reclamation was to line the canal or use pipes to save canal water.[2] There was no study or documentation produced. Unfortunately, the agreement to get funding required that a portion of the saved water would be transferred to the Pecos watershed. This perceived "giving up" of water rights caused the project to lose support in the district. Water rights are precious and obviously carefully guarded.

An NMSU study produced in 2006 provides descriptive information about canal conditions that provides a useful starting point in locating areas of water loss.[3]

There are two sections of canal to consider in this NMSBA study. The first is the main canal from Conchas Reservoir to the county line, and the second is the distribution system within the district, i.e., the laterals. See Figure 2. Arch Hurley cannot afford the piping in the whole of the main canal, but the laterals are much cheaper and easier to finance in $50k increments. The main canal has a pipeline price tag of $100M or more.[4]

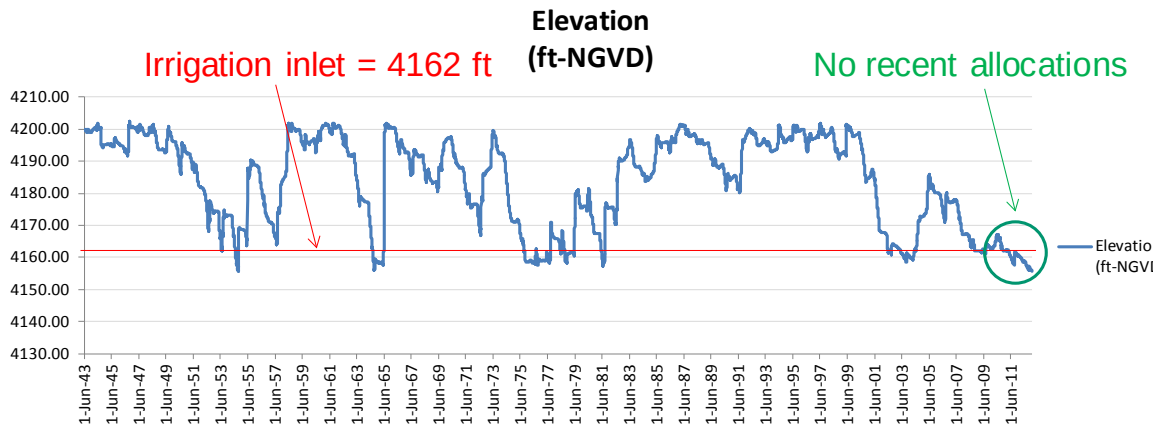
Six pumps at the Conchas dam can be used to lift water into the canal when the lake elevation is below the inlet spillway. See Figures 3 and 4. These diesel pumps are much too expensive to operate as a method to supply irrigation water given the current state of the canal and the value of water. Three or four pumps (each with a capacity of 20,000 gallons/min) are needed to supply the demand of the system. The last time the pumps were used was in the 1970s. AHCD took advantage of the recent low lake level to remove silt that had accumulated in the water inlet to the pumps. Now the pumps have access to water and are functional.

[2] C. J. Weigel, personal communication.
[3] King, J. Phillip; Hawley, John W.; Hernandez, John; Kennedy John F.; Martinez, Eluid L.; "Study of Potential Water Salvage on the Tucumcari Project Arch Hurley Conservancy District," New Mexico Water Resource Research Institute, New Mexico State University, June 2006.
[4] The district has applied to the USDA for a grant to fund removal of woody vegetation along the main canal. This was denied because USDA believes the district should pay for this as part of regular upkeep.



Source: King, et.al, "Study of Potential Water Salvage on the Tucumcari Project," p. 4.

Figure 2: Map of Conchas Reservoir and irrigation system.



Source: U.S. Corps of Engineers, via Arch Hurley Irrigation District.

Figure 3: Conchas Reservoir elevation over the past seventy years shows that periodically the lake level is below the irrigation inlet of 4162 feet. At this point pumps can be used to deliver water to the AHCD irrigation system for five feet of lake elevation.

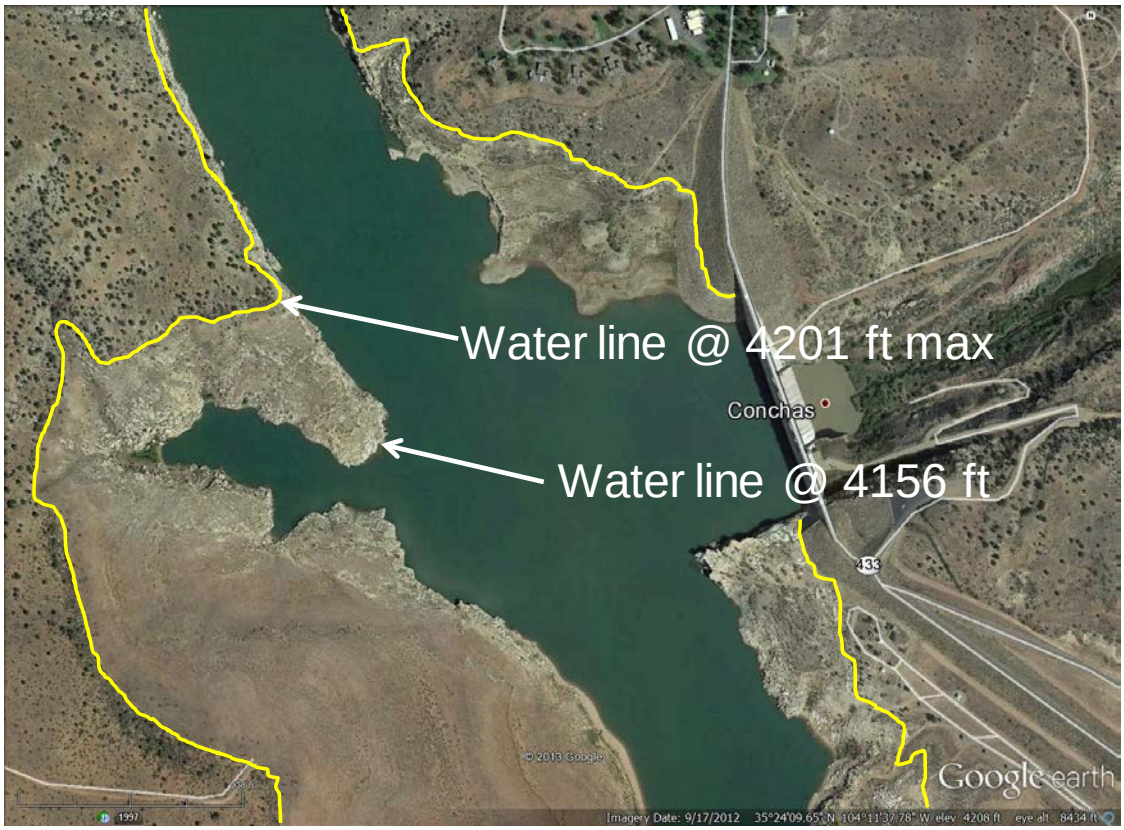


Figure 4: Conchas Reservoir has suffered a drop in elevation because of the long-running drought in New Mexico.

Arch Hurley has applied for a $50k grant to evaluate installing new pumps. Results of the application will be known later in 2014. Information from the application could be synergistic with our work as we study how to minimize canal losses most efficiently and their study would optimize the dam pumps. Also, there is a ten percent cost share required for the grant that perhaps can be defrayed by the NMSBA project. There will also be the same cost share required for project implementation (perhaps $500k total project cost). Modern pumps are expected to cost about $70k each and have much higher efficiency than the originals. These could possibly be powered by renewable energy rather than by diesel.

In the past, good years for rainfall and a full reservoir allowed the canal to be full throughout the growing season, essentially six months of the year. This was typical of the 1982 to 2001 period. During the more recent period a lack of water has precluded this. For example, in 2002 there was water in the canal for only 6 weeks. Intermittent canal water causes an increase in infiltration losses as the soil is repeatedly soaked and then allowed to dry.

The main canal traverses the property of only one landowner, the T4 Cattle Company. This ranch has 180,000 acres and has been owned and operated by the same family since 1902.[5] To build the canal, BOR purchased a strip of land from the T4. After the canal was completed, the land was sold back to the ranch, with an easement paid for by BOR to provide enough water to support 300 mother cows year round. The ranch runs a total of about 2,500 mother cows.

There are two potential uses for the electricity produced by this NMSBA project. First is sale of electricity to Farmers Electric Cooperative of New Mexico, Inc.[6] Second is to power pumps (if the renewable energy were located near the Conchas dam). The main line is gravity fed, and there are no pumps along the main canal. Some landowners have pumps that are driven by electricity, diesel, or gasoline to pressurize water for sprinklers. Other landowners use gravity-driven flood irrigation. The low-lake pumps at the dam could be powered by renewable electricity rather than diesel.

A potential issue to keep in mind during our project is the presence of Federal Energy Regulatory Commission (FERC) rules with respect to impoundments to produce hydropower. FERC regulates “dams,” but it is unclear precisely how “dam” is defined. A past NMSBA project at Elephant Butte Irrigation District (EBID) encountered this issue also.[7] Any hydropower development on the canal should be kept small enough to avoid FERC jurisdiction and its associated expenses.

Technically it might be feasible to install wind power to drive AHCD electric pumps at the dam. There may be regulations that preclude this at an existing Corps of Engineers dam. Conchas Dam is an undeveloped hydro site that has a potential hydropower potential of 2,078kW.[8]

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[5] Hecox, Ross, “Family Fortitude,” Western Horseman. http://www.westernhorseman.com/component/content/article?id=866:family-fortitude.html.

[6] http://www.fecnm.org/content/cooperative-history. Note that one of the Bidegain family, owners of T4 Cattle Company, sits on the cooperative’s Board of Trustees.

[7] Energy Analysis Team, “NMSBA Project: Phase 1 Report: EBID Low-Head Hydro,” LA-UR-11-12084, December 12, 2011.

[8] Conner, Alison, M.; Francfort, James E.; “U.S. Hydropower Resource Assessment for New Mexico,” Idaho National Engineering Laboratory, DOE/ID-10430(NM), March 1997, p. 4.

Current prices of water at AHCD include an assessment fee of $11 per acre (which must be paid whether or not any water is received) plus $10 per acre foot for water delivered to the field. As a comparison, drought-stricken California water rates are much higher as communities have bid against each other for small amounts of surplus state water. For example, Kern County surplus water was recently priced at $1,350 per acre-foot and Madera Irrigation District water went for $2,200 per acre-foot.[9] General California water costs per acre-foot (af) are $1,100 for recycled water, between $150 to $800 for well water, and $300 for reservoir water. Desalination plant water costs at least $1,500/af.

II. SUPPLY DURATION CURVES

Each energy generation technology considered in this report relies on a specific resource, be it wind, solar irradiation or water. The first project task focuses on estimating the amount of these resources that are available to AHCD throughout a typical year. Based on this information, a computation of potential electricity production can be made.

A. Wind

The energy supply curve for wind is contained in Figure 5. These data are for the Tucumcari Mini Airport over a ten-year period and are meant to reflect the expected supply available to a turbine in the general area. The mean and standard deviations are shown in the figure as well. The graphic as a whole demonstrates that wind resources are relatively steady in the region.

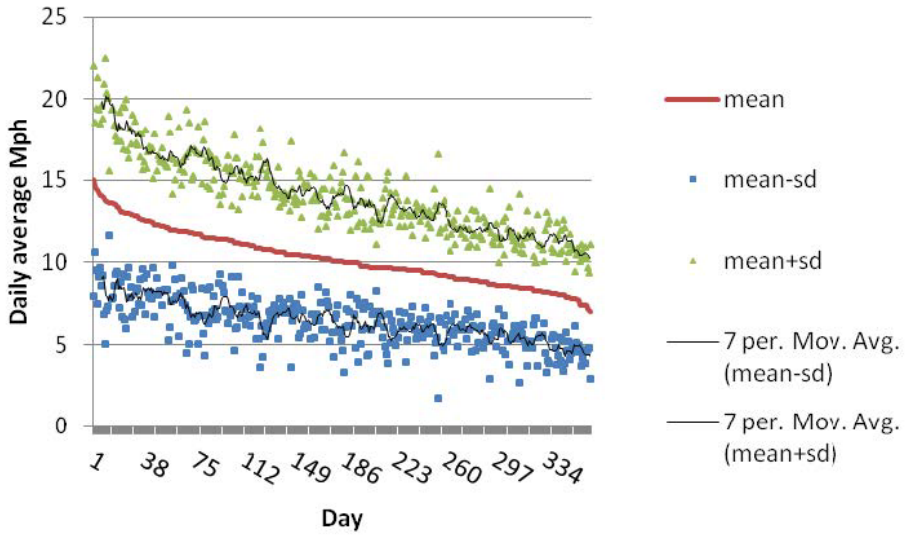


Figure 5: Graph showing wind resource available for possible electricity production based on Tucumcari KTCC Municipal Airport data from 2004 to 2014.

[9] Kacik, Alex, "Blame It on the Rain," missionandstate.org, March 31, 2014. http://www.missionandstate.org/features/blame-it-on-the-rain-lakecachuma-drought/.

B. Hydro

Monthly water flow data at the Conchas Dam has already been collected by the Los Alamos team during last year's NMSBA study. An example supply duration graph for Conchas canal water is shown in Figure 6. The functional and operational requirements for the pipelines are based on the capacity needed to provide water to farms given current technologies. The method used to deliver water to the fields is critical to this determination. For example, a farmer with Conchas Reservoir water rights (but not part of AHCD) converted from flood irrigation to pipes, pumps and sprinklers. His water use dropped by a factor of about nine. [10]

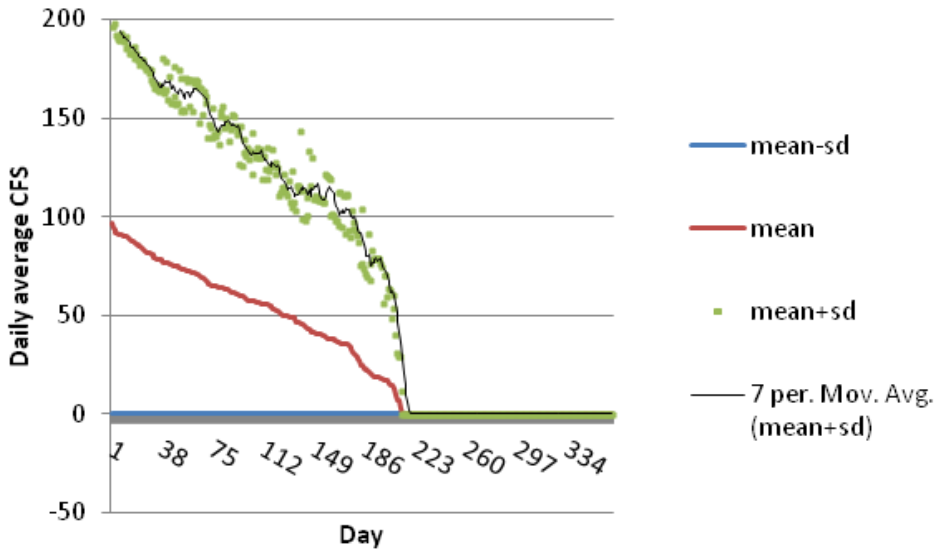


Figure 6: Graph showing water resource available for possible low-head hydropower development based on Conchas outflow data from 2003 to 2013.

The required water flow to satisfy the AHCD farms can be calculated by multiplying the acre feet required for an example crop by the number of planted acres, then converting to cubic feet per second (cfs). The expected flow can be used to predict the required capacity for the pipeline. It is important to keep a system-wide perspective of how much water is being lost and what is really required given today's farming technologies. The AHCD Board decided to specify 300 cfs as the capacity of the pipeline, while allowing the open canal to handle storm water runoff.[11]

It is important to size the pipe correctly. Big pipes have the ability to handle maximum flow but are much more expensive. For example, Larry mentioned that 24-inch pipes are being used in some distribution laterals where ten-inch pipes would be sufficient. A large pipeline that can handle maximum flow may be prohibitively expensive given AHCD finances. A recent example could be illustrative of maximum flow for the system. In September 2013 there was a storm that dropped significant rainfall in the area. A total of 3.81 inches of rain occurred on September 11

[10] Larry Perkins, personal communication, March 20, 2104.
[11] Phillip Box, email, August 14, 2014.

and 12, 2013.[12] Such a storm event is expected to be handled by the existing canal, not the capacity of the pipeline.

The flow was 250 cfs at full release during the 1970s when flood irrigation was used. The use of sprinklers today means the system may be more efficient. A minimum AHCD order is considered to be 40 cfs.[13] Water is turned off at the dam for any requirement lower than this because it is inefficient to transfer water at lower flows given the current canal structure. The 40 cfs at the County Line indicates 80 to 90 cfs flow at the dam. Also, the flow should be steady rather than intermittent. Any interruption in flow should only be for a few days because it increases infiltration and evaporation losses. Figures 7 and 8 show the flow from the Conchas Reservoir to Arch Hurley over a ten year period and in a 15 day sample, respectively.

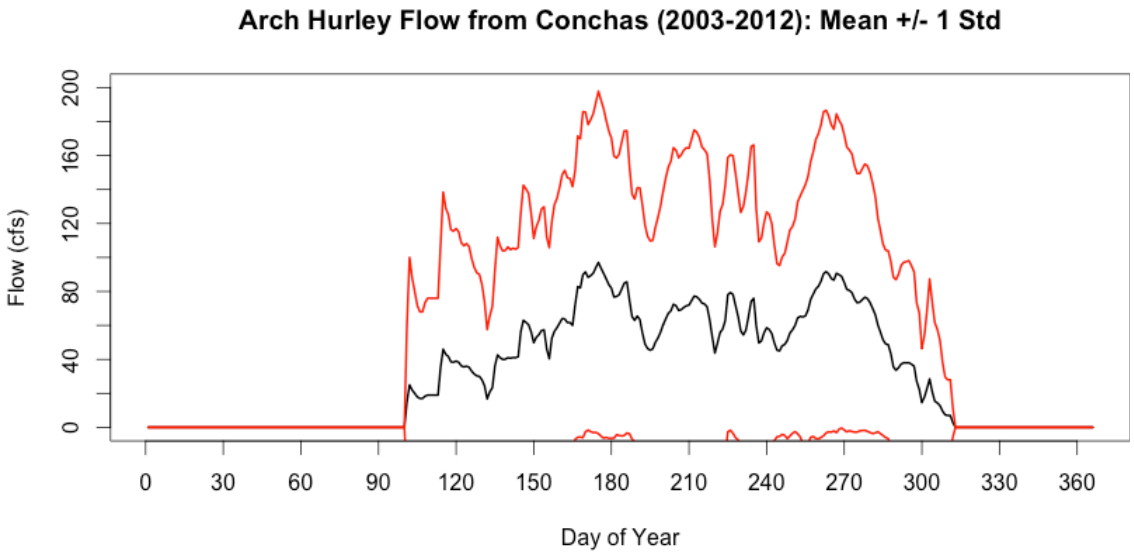


Figure 7: Graph showing annual flow in cfs from the Conchas Reservoir to Arch Hurley based on data from the last ten years. The mean +/- one standard deviation is denoted by the red line.

[12] NOAA, National Climatic Data Center.
[13] Franklin McCasland, personal communication, April 25, 2014.

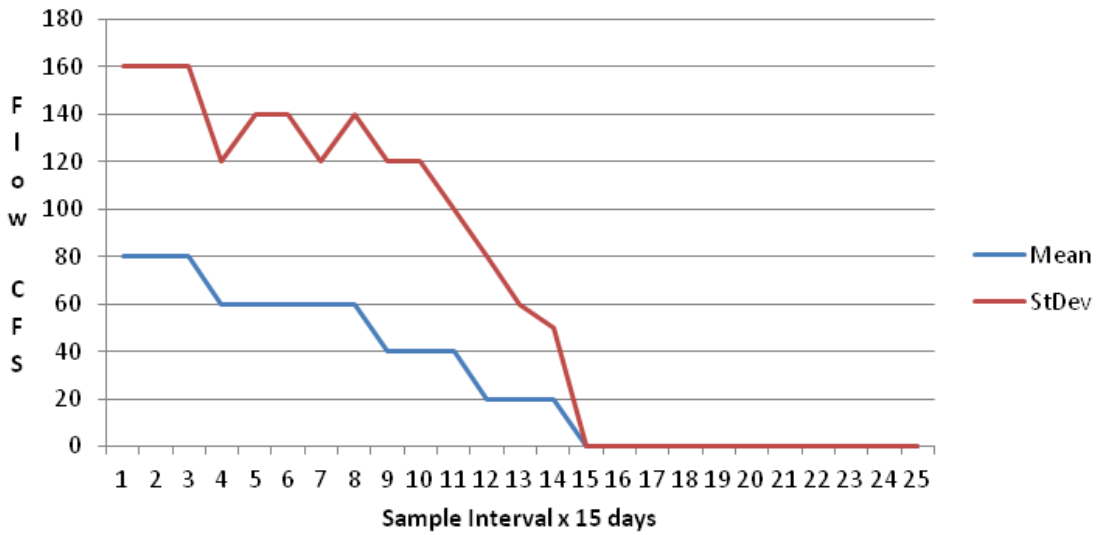


Figure 8: Graph showing a sample interval of 15 days of flow in cfs from the Conchas Reservoir to the Arch Hurley Conservancy District.

C. Solar

Figures 9 and 10 show the energy supply curves for solar resources in New Mexico. Solar is available during the daylight hours, and varies noticeably by season. The Zia Pueblo solar data show estimated peak capture of about eight kWh per m^2 per day during the summer. Winter rates are estimated at less than half of the available capture.

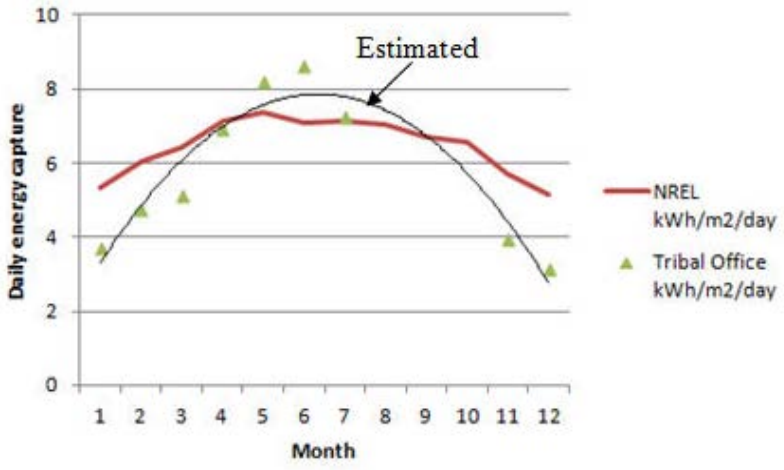


Figure 9: Solar resource available at Zia Pueblo in New Mexico.

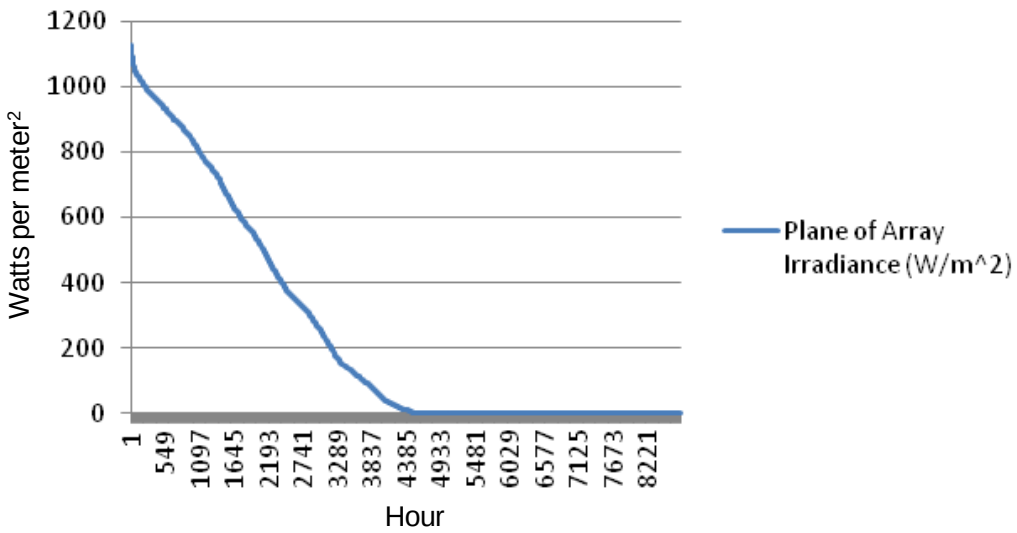


Figure 10: Graph showing solar irradiance resource (W/m^2) available for possible electricity production based on Tucumcari KTCC Municipal Airport data from 2004 to 2014.

D. Natural Gas

The supply of natural gas is controlled by a well-established market as opposed to nature. Therefore a figure is irrelevant as we do not need to determine the supply obtainable. Sufficient gas is available to drive a microturbine year-round.

III. PRESREENING OF ALTERNATIVES

This task down-selects a primary and back-up electricity production technology to be evaluated for engineering feasibility in the next section. The methodology used is multi-attribute decision analysis, applied via a commercial software package called Criterium Decision Plus[14] to build an analytical hierarchy process (AHP) model and calculate the results. Figure 11 shows the analysis steps used in the evaluation; the discussion below is organized along these steps also.

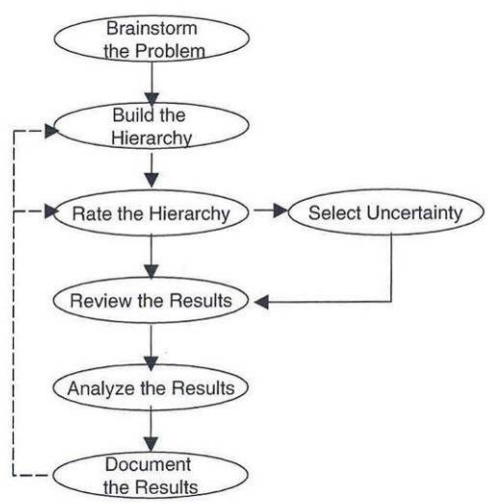


Figure 11: Project evaluation follows standard decision analysis steps.

During the first step of the process, "Brainstorm the Problem," the goal of the model (*Select Electricity Generation Technology*) is defined and possible

[14] Infoharvest, Inc., Seattle, WA, www.infoharvest.com.

evaluation criteria are considered. Each criterion must be defined to make it independent of the others.

After narrowing the list of criteria, the hierarchy is built as shown in Figure 12. The goal of selecting a technology is on the left side; next are listed the five top-level criteria and two sub-criteria that help attain the goal: Revenues, Costs, Business Model, Permits, and Socio/Political. The right side of the hierarchy has four technologies to be evaluated. Each technology is scored against the six green-highlighted criteria shown in the figure.

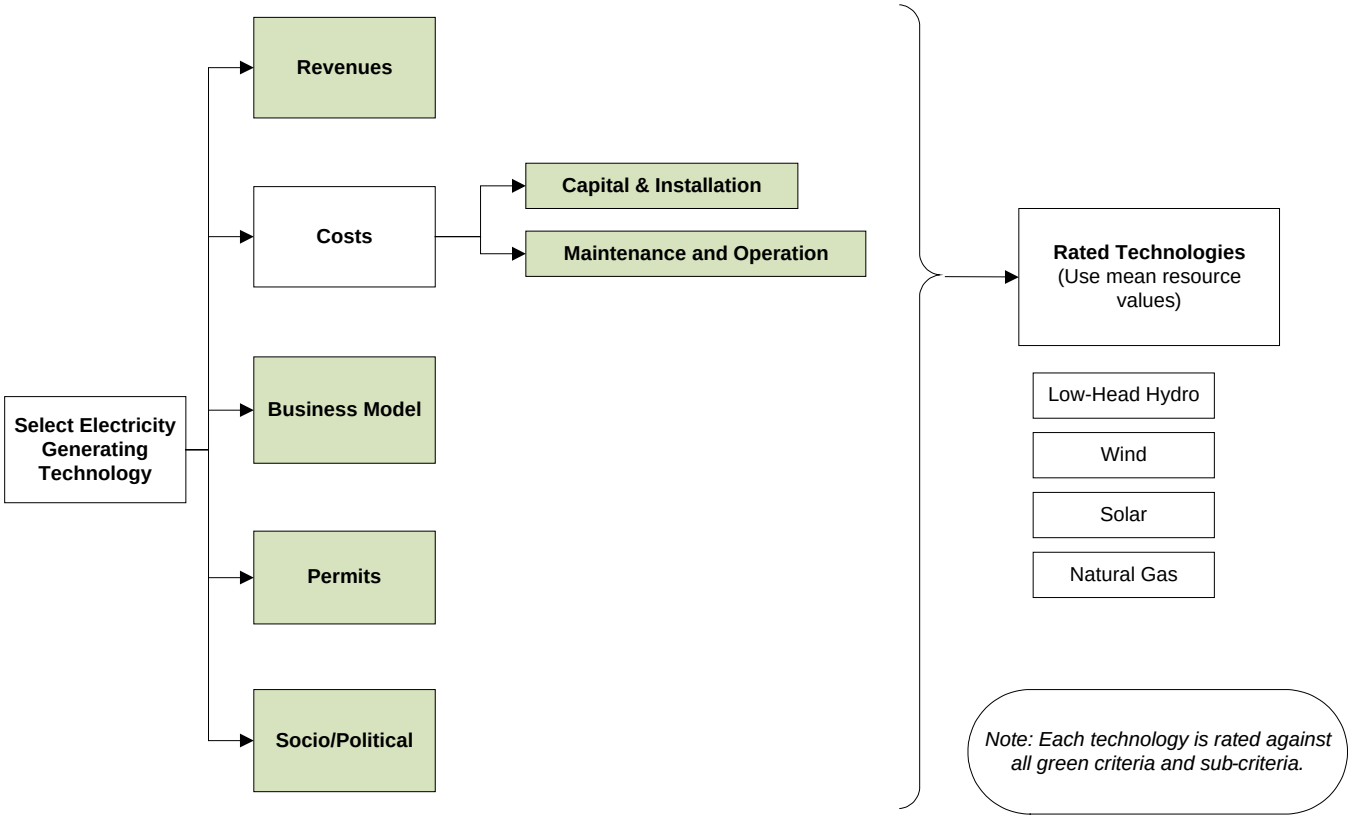


Figure 12: Hierarchy of the decision analysis model shows the five criteria that are used in scoring the four alternative electricity generating technologies.

A. Criteria Definitions

Primary drivers for technology selection are production capability and the ability to sell power to a local utility, its costs for installation and operation, the viability of a business model, issues related to permitting, and social acceptability.

1. Revenues

Revenues are created by selling a quantity of electricity generated annually by the technology. The resource values for each month along the supply duration curve can be multiplied by the generation factor to compute power supplied over a typical year. The price of electricity paid by the utility is the final parameter used to get annual revenues. The mean supply duration curves

will be used to compute revenues for each technology. In the pre-screen, we use a 500kW capacity and consider what portion of the year this power is produced.

2. Costs

Capital costs include the design, equipment, and installation costs to get each technology ready to operate. Maintenance and Operation captures the costs of actually running the equipment to produce electricity.

3. Business Model

This project depends on a private developer being willing and available to invest in the technology system. This criterion addresses the viability of a business model in making this happen. A possible model is the shared-energy savings program that could allow revenues from electricity production to be partly used to amortize the cost of pipeline installation. Also, there are federal incentives for renewable energy projects specifically designed to support agricultural producers such as the Rural Energy for America Program (USDA) that provides grants of up to 25 percent of project cost.[15]

4. Permits

This criterion includes all issues related to permitting the technology project, including legal, environmental, and threatened and endangered species. Projects located along the Conchas Canal will have issues associated with private land, whereas some technologies may be located on Bureau of Reclamation land.

5. Socio/Political

This criterion considers the presence of prehistoric and historic resources including those associated with ancestral pueblo and homestead eras. Any possible environmental justice issues are included here. Also important is how close the site is to residential areas or pueblo lands (even though pueblo areas may not be actually populated). Also included are nuisance conditions (dust, noise, lights, and odors) and aesthetic impacts (view shed sightlines and possible visual screening provided by vegetation and topography).

B. Technology Options

There are four possible electricity production technologies considered in this project. Each must be well-defined based on a standard production capacity to allow ease of scaling and decision analysis scoring. The difficulty is a small wind turbine is generally has more capacity than low-head hydro. For example, a typical efficient wind turbine is 500 kW, whereas two hydro turbines considered in the EBID project had a capacity of 10 kW driven by an average flow of 100 cubic feet per second (cfs). Gas-fired microturbines can be purchased with 250 kW of capacity. A standard unit allows us to multiply the installation to get to similar capacities across technologies. The pre-screen uses a 500 kW capacity for comparison.

There is an electricity line that runs along Route 104 to Conchas Dam. The canal generally runs along this road.

[15] http://www.rurdev.usda.gov/BCP_ReapResEei.html.

1. Wind

Wind turbines have a well-established market with available developers in New Mexico. The wind resource in the project area may allow significant flexibility in locating wind turbines, from the Conchas Dam all the way to Tucumcari. The optimal location will be near existing power lines to allow sales to the electric utility. The type of unit used in the comparison is a 500kW turbine with a 50-meter tower.

2. Low-Head Hydro

Knowledge from the EBID project can be used to estimate capacity for an appropriately sized micro hydro unit for the Conchas Canal. The supply duration curve for water flow will be critical for this. Location will be relatively complicated because sufficient canal gradient needs to be combined with proximity to utility power lines. Three clusters of ten turbines each will be needed to provide a 500kW capacity.

3. Photovoltaic Solar

Solar panels can be installed at most locations between the Conchas Dam and Tucumcari. Scaling is simple to match the standard unit capacity (500kW) for this analysis. Locating the system is easy and will be driven by proximity to existing power lines. About 2.5 acres of land is needed for the fixed-mount PV array.

4. Natural Gas Microturbine

Two standard gas-fired turbines of 250kW capacity can be located near a gas supply line located in Tucumcari.[16] This is not a renewable energy technology, so there may some limitations to the type of business model that could be used. The key determinate for location is the combination of a gas pipeline and power lines.

C. Rating the Hierarchy

The next step in the decision analysis process is to rate the hierarchy, i.e., apply weights to the criteria based on relative importance, and score the alternatives against each criterion. A seven-component score ranging from *Finest* to *Unsatisfactory* is given for each alternative against each criterion. The basic algorithm is to multiply how each alternative scores against each criterion by the relative importance of that criterion (i.e., its weight). Those products are then summed over all the criteria to provide a total decision score, thus serving as a measure of how well each alternative fits the decision model.

1. Weights

The weights of the criteria with respect to the goal were chosen by the LANL technical team based on a descriptive scale with points attached: *Critical* (100 points), *Very Important* (75 points), *Important* (50 points), *Unimportant* (25 points), and *Trivial* (0 points). The initial results reported in this paper are based on an even weighting on the five top-level criteria—all given the weight of *Important* (see Table 1).

[16] Flex Energy, Flex Turbine MT250, http://www.flexenergy.com/flexenergy_flex_turbine.html.

TABLE 1
Top-Level Criteria Weights for Four Perspectives

	Weight Descriptors for Different Perspectives			
Top-Level Criterion	**Equal Weights**	**LANL Team**	**Arch Hurley**	**Environmentalist**
Revenues	Important	Critical	Critical	Trivial
Costs	Important	Critical	Critical	Trivial
Business Model	Important	Important	Critical	Important
Permits	Important	Very Important	Important	Critical
Socio/Political	Important	Trivial	Very Important	Critical

In addition, a form of sensitivity analysis was completed where three different perspectives were used to set the weights. Results were then compared under the perspectives to see if the ranking of technologies differed. Arch Hurley will place relatively more weight on the business model, as they need a plan that attracts potential developers and investors. From the AHCD's perspective, this criterion is at the same high level of importance as the costs and revenues of the project. When consulted, they also agreed that, while a developer may do the majority of the work in regards to acquiring permits, the AHCD still needed to have some investment in the issue. Therefore, they weighted Permits as *Important*. The environmental activist is far more concerned with permitting factors and the socio/political consequences of the project than with any other aspect. As a result, those two factors are given critical weights whereas economic factors are given little importance. Finally, the LANL technology team will be most concerned with both the feasibility and implementation of the project. This involves high-level weighting on Revenues and Costs, with medium-level considerations for the potential "show-stopper" criteria of permitting and business model. The weights under these different perspectives are listed in Table 1.

The verbal descriptors of weights are normalized for computation of the results. Table 2 shows how this is done. The normalization takes account of the number of sub-criteria under each top-level criterion. For example, Costs has two sub-criteria that are valued as *Important* and given user scale values of 50 points on a scale of 0 to 100. Each sub-criterion's normalized weight is calculated as 50/(50+50) = 0.5. In a sense, the influence of Costs is divided into two "sub-influences" represented by the sub-criteria. On the other hand, the top-level criterion Revenues has no sub-criteria. Therefore its influence on the total is not split into components.
The Criterium DecisionPlus software automatically calculates the accumulated weight for each path in the hierarchy that connects alternatives to the goal. This is done by multiplying the top-level criterion's normalized weight by that of the sub-criterion along the path (see Table 2). For example, Capital and Installation is a sub-criterion of Costs. The top-level weight is 0.3 and the sub-criterion weight is 0.5, so the accumulated weight along the path of the hierarchy is 0.3 x 0.5 = 0.15, or fifteen percent. The total of the six accumulated weights is one.

TABLE 2
Calculation of Criteria Weights for LANL Perspective

Criterion	Descriptor	User Scale Value (0 to 100)	Normalized Scale Value (0 to 1.0) {1}	Accumulated Value {2}
Revenues	***Critical***	***100***	***0.30***	0.30
Costs	***Critical***	***100***	***0.30***	
Capital & Installation	Important	50	0.5	0.15
Maintenance & Operation (M&O)	Important	50	0.5	0.15
Business Model	***Important***	***50***	***0.15***	0.15
Permits	***Very Important***	***75***	***0.22***	0.22
Socio/Political	***Trivial***	***10***	***0.03***	0.03
Total				***1.00***

{1} The top-level criteria normalized scale values sum to one. Within each top-level criterion, the weights of its sub-criteria are normalized by dividing each weight by the total of the weights. For example, Capital & Installation is 50/(50+50) = 0.5.

{2} The accumulated value of each sub-criterion is found by multiplying the top-level criterion's normalized weight by that of the sub-criterion. For example, the accumulated value for Maintenance & Operation is 0.30 x 0.5 = 0.15, or an approximate 15% weighting factor. The sum of the accumulated values is one.

Each sub-criterion is scored with respect to the alternatives using a descriptive scale ranging from 100 to zero: *Finest* (100 points), *Excellent* (83.3 points), *Above Average* (66.7 points), *Average* (50 points), *Below Average* (33.3 points), *Poor* (16.7 points), and *Unsatisfactory* (0 points). The reasoning behind the scores for each alternative is described below; the scores for the criteria are listed in Table 3.

TABLE 3
Criteria Scores for Model

Criteria	Low Head Hydro	Wind	Photovoltaic Solar	NG Microturbine
Revenues	Excellent	Excellent	Below Average	Excellent
Capital & Installation	Above Average	Above Average	Below Average	Above Average
M&O	Average	Average	Finest	Unsatisfactory
Business Model	Above Average	Average	Above Average	Finest
Permits	Unsatisfactory	Average	Finest	Average
Socio/Political	Finest	Average	Excellent	Below Average

2. Scores for Revenues Criterion

The electricity quantity produced is multiplied by the value of electricity sold to local coop or utility. The quality of power is important in determining this value. When is the power generated? How stable is it? How reliable? How "firm" is the power? "Firm power" describes electricity that is available a large percentage of the time at rated capacity. One-hundred percent firm power can never be accomplished—even based-load production such as coal-fired plants is only 85 percent firm because of maintenance requirements. In general, 85 percent is the best that can be achieved by any power plants today.

Texas has 12,000 MW of wind power. Texas has created a firming market because they have so much unfirm power from wind. This market combines gas turbines with wind to get firmer power. No firming market exists in New Mexico. If New Mexico gets enough renewable energy production in the future our state may have to set up such a market also. Currently New Mexico utilities can pay whatever they want for renewable power. This is a huge issue for our project because there could be a very low price. Without a firming market in place we cannot be sure of the prices that will be paid. The cost of firming service in Texas is about $0.05/kWh. That is, the firming price of $0.05/kWh is added to the cost of producing renewable energy to create a firm-power price. The value of firm power might be $0.10/kWh, but perhaps 50 percent of this is firming cost.

It is expected that all renewable power will receive a similar price from the utility. Consequently, price is not a discriminator in the rating scores for the Revenues criterion. Focusing on the quantity and "firmness" of power from the alternatives leads to the scores. Three technologies have similar quantities and a firmness rating of about 40 percent: wind, gas microturbines, and hydro. These alternatives score *Excellent*. Solar has a firmness of only 20 percent, which causes its score to be *Below Average*.

3. Scores for Costs Sub-Criteria

<u>Capital and Installation.</u>

Installation includes the cost of interconnection, that is, the step-up stations and the line tap to connect to a 69kV line. This cost is $100k for a 2-3 mile hookup, and about half this for a short connection such as at the Tucumcari substation. This means solar and gas microturbines have a smaller hookup expense: $50k.

Gas microturbines cost $850k to purchase two Flex MT250 units including a $50k interconnection. Adding installation costs of 30%, the total installed cost is $1.1M. Installed capital cost of a 500 kW wind turbine with a 50 meter tower with interconnect is $1.2M. (This assumes $50k for a short hookup because it is built close to the NM 104 to avoid gravel road construction). Solar cost including interconnect and a PV panel 2.5 acre array is $1.5M. Hydro is three-times the installed cost of $320k of one cluster in the Elephant Butte report[17] plus $100k for interconnection—the total cost is $1.1M. Given these costs, the scores are *Above Average* for gas microturbines, wind, and hydro, and *Below Average* for Solar.

[17] Energy Analysis Team, "NMSBA Project: Phase 1 Report: EBID Low-Head Hydro," Table 3, p. 9.

Maintenance and Operations.
Gas microturbines have a fuel cost for gas that is about $0.092/kWh for a small user on New Mexico Gas Company's system.[18] Although there is no labor assumed for operations (the utility will run it remotely), maintenance is added of about $18k per year. Wind turbines have annual maintenance of $35k, with no operational labor. Maintenance includes washing and replacing blades, and no drive-train replacements. Solar PV has maintenance of $5k/y to wash panels to remove dust, and the cost for occasionally replacing micro-converters. Hydro power costs $45k/y for maintenance based on a factor of three-times higher than the Elephant Butte cluster. This maintenance is for cleaning traps of trash and debris that flows into open canal. Also included is lubricating the machines and gear trains. Both wind and hydro are within $10k in maintenance with such a high uncertainty that we score both as *Average*. Solar is scored as *Finest*, and gas microturbines score *Unsatisfactory*.

4. Scores for Business Model Criterion

Ultimately any choice of technology relies on a private developer seeing it as a viable project. The basic model is: energy is produced, which creates income, which supports pipeline improvement. A viable concept is a "shared energy project." For example, Johnson Controls conducts an energy audit of all equipment in an industrial plant. Their audit report shows improvements that are possible to save energy costs. The developer buys and installs new equipment, then collects a portion of the energy savings to cover their development costs. Shared Savings is our assumed development option. (This is now called Energy Performance Contracting—EPC).

Uncertainty in resource is a problem for EPC—there is a need for consistent energy savings to pay back the developer. This is key in scoring the alternatives. Gas microturbines are very reliable and have good quality power so they win participation by utilities and developers—score is *Finest*. Wind has the highest variability and scores *Average*. Water in dammed in the Conchas Reservoir, which creates a relatively smooth resource for hydro when the canal is flowing—score is *Above Average*. Solar has some variability but less than wind—score is *Above Average*.

5. Scores for Permits Criterion

Hydro power has a legal issue that must be resolved with respect to FERC. The key issue is how to define a dammed water body. If FERC rules that canal ponding is a "dam" this will kill the option. Uncertainty is high; there is a potential show-stopper given experience of the EBID project. The hydro technology must create an impoundment to get a head for the turbine well. This could put us into FERC jurisdiction. The AHCD project is effectively the same as EBID project. This is hard to mitigate—score is *Unsatisfactory*.

The wind turbine assumes a tower of 50 meters. The lesser prairie-chicken has not been seen in the area for a long time. None have been north of I40. The law says the project must have no negative impacts on occupied land or suitable land for the chicken. This is an on-going problem that is not yet well defined. This is very small project with a single turbine so there probably will not be a significant issue. There are also concerns about putting any sort of wind technology on T4 Ranch land. T4 is located within San Miguel County, a county that has banned the placement

[18] Gas price is computed using prices shown on NM Gas Co.'s website and applying scaling factors to reflect assumed gas consumption of microturbines.

of wind technology within its boundaries. The AHCD has stated that T4 is currently trying to be rezoned as part of Quay County and will most likely succeed within the next few years. Nevertheless, the lack of certainty on this issue requires that a location within Quay County be found and permitted if this option is to be pursued. (Large-scale projects of multiple wind turbines have the problems.) Because the scale is small, the score is *Average*.

Solar will be located close to town, so there are no habitat worries. Disturbed land will be used, and no native grasses are left in Tucumcari city limits. One possible issue is optical glare that could affect flight paths for the Tucumcari airport. This is assumed to be mitigated by careful location choice—score is *Finest*.

An air quality permit will be required for gas microturbines. Also, a safety permit will be needed if it is near a residential area; this might be a utility issue. Overall, the issues are comparable to wind—score is *Average*.

6. Scores for Socio/Political Criterion

Low-head Hydro has a very low profile, and is remote, quiet, and has no problems with population. Score is *Finest*.

Wind is also remotely located, but has bird and bat kill potential. There is significant noise for any people residing nearby, but this is not expected to be an issue. People will see it from the road, but it is should not be a disturbance. TV and radio reception interference can be a problem when blades get wet, but again the remote location mitigates this. Overall, the potential disadvantages of wind have been minimized, so its score is Average.

Solar PV is not in a remote location. Glare is only a problem for planes and is easy to mitigate. No political problems are expected, as people generally do not complain about these installations. Score is *Excellent*.

Microturbine machines make noise, and people will hear this because of it will be installed near the Tucumcari substation. What is significant is the hours of potential operations. It is not expected to be run at night because of off-peak electricity value and the noise issue. There is a potential for leaks of oil, and some pollution issues that are very minor. One detriment is there is no “wow” factor such as with a renewable energy source. We assume that any fire danger (e.g., from an accident by vehicle) will be mitigated. Score is *Below Average*.

D. Results

The weights for the criteria and the scores of the alternatives are combined to create the final results of the decision model. The scores described above and in Tables 2 and 3 are normalized in a similar fashion to what is done with the weights. That is, the scores of the renewable technology alternatives against each sub-criterion are recomputed so that the scores add to unity. This is done by dividing each alternative’s score by the sum of all the model’s alternative scores.

The decision score is found by computing the weighted sum of the scores of each alternative. The sum of an alternative’s scores against all the sub-criteria multiplied by their appropriate weights is the total score.

The chart in Figure 13 shows the results for the different energy technologies using each of the four weighting schemes for top-level criteria (Equal, LANL, AHCD, and Environmentalist). Some of the alternatives have red bars in the chart, which signify a violation of one or more rules in the model. Rules are defined to highlight important criteria and sub-criteria where a score of *Unsatisfactory* indicates a possible major problem with that alternative. In this model six rules are defined, as shown in Table 4. Even though an alternative may score very well against many criteria and have a high total score, a violation of a rule indicates a potential problem exists in developing or implementing the technology. In coloring the score bar red in Figure 13, the reader can see the final score and also the fact that a potential "show-stopper" issue exists. Low-Head Hydro violates the rule "Permit Attainment" because ambiguity in defining a dammed water body may bring the project under FERC regulation through either construction or actual turbine usage. Unlike the other four technologies, Gas Microturbines have high operation costs due to fuel usage. These costs actually exceed any revenue generated by the technology, consequently violating the rule "M&O Feasibility."

Sensitivity analysis using the different management perspectives from Table 1 shows no significant changes to the result aside from a distinct top-ranking for Solar PV in the Environmentalist perspective. Environmentalist weights are significantly higher for Permitting and Socio/Political; LANL team weights focus more heavily on Revenues and Costs; AHCD weights include an added emphasis on Business Model. These varying perspectives and weights give confidence that any top-ranked technology would serve as a robust answer. While the results show Solar PV winning in three out of the four perspectives, the scores seen in the AHCD, LANL, and Equal Weights perspectives are all within one standard deviation of each other. This lack of a decisive victor in the decision analysis led to a request for AHCD input as to which two technologies would move on to feasibility analysis. Upon consultation, Wind and Solar PV were the technologies chosen.

Figure 13: Results for different weights show that Solar PV is the highest ranked option in three of the four cases. Red bars signify that one or more criteria were scored as "Unsatisfactory." Criteria weighting for these results is based on Table 2.

TABLE 4
Rules for Criteria

Rule Name	Definition
Capital and Investments	**Capital and Investments** must be better than *Unsatisfactory*
M&O Feasibility	**M&O** must be better than *Unsatisfactory*
Permit Attainment	**Permits** must be better than *Unsatisfactory*
Revenue Assessment	**Revenues** must be better than *Unsatisfactory*
Business Model	**Business Model** must be better than *Unsatisfactory*
Socio/Political	**Socio/Political** must be better than *Unsatisfactory*

IV. FEASIBILITY ANALYSIS

This section considers the engineering and economic feasibility of the top two technologies determined in the previous section. A cursory evaluation of siting options is used to establish potential locations for either a set of wind turbines or a 500kW solar panel array. A preliminary engineering design is used to help scope the capital and operating costs.

A. Siting Options

The two options being considered in the feasibility analysis, Wind and Solar PV, require approximately 2.5 acres per turbine and 5 acres for operation, respectively. When considering possible sites, the most important variables are the availability of the required resources, land topography, and any permitting or socio/political issues that could create “show-stoppers.”

Initially, a number of sites were considered on T4 land near the Conchas Canal. These areas were deemed insufficient after consulting with AHCD, as there are various complications that occur when working on T4 land. As mentioned above, installing a wind turbine is currently impossible on this land due to the restrictions imposed by San Miguel County. A solar panel array would require additional easements from T4, and revenues from the project would most likely be shared as a result. Considering the revenue sharing that is likely to occur between a developer and Arch Hurley, further splitting of revenue would potentially defeat any advantages of the installation.

Upon further discussion with Arch Hurley, three main siting locations were analyzed. See Figure 14. The first is the “Y Site” on Bureau of Reclamation property near what is called the Y Substation. Located at a split in the Conchas Canal, this location is beneficial in that it is close to an electrical substation. However, this land does not have a consistent level and is below the floodplain. Considering the closeness of the land to the canal and its periodic flooding, this site is unsuitable. Figures 15 and 16 show the land initially considered at the “Y Site” property and the nearby substation.

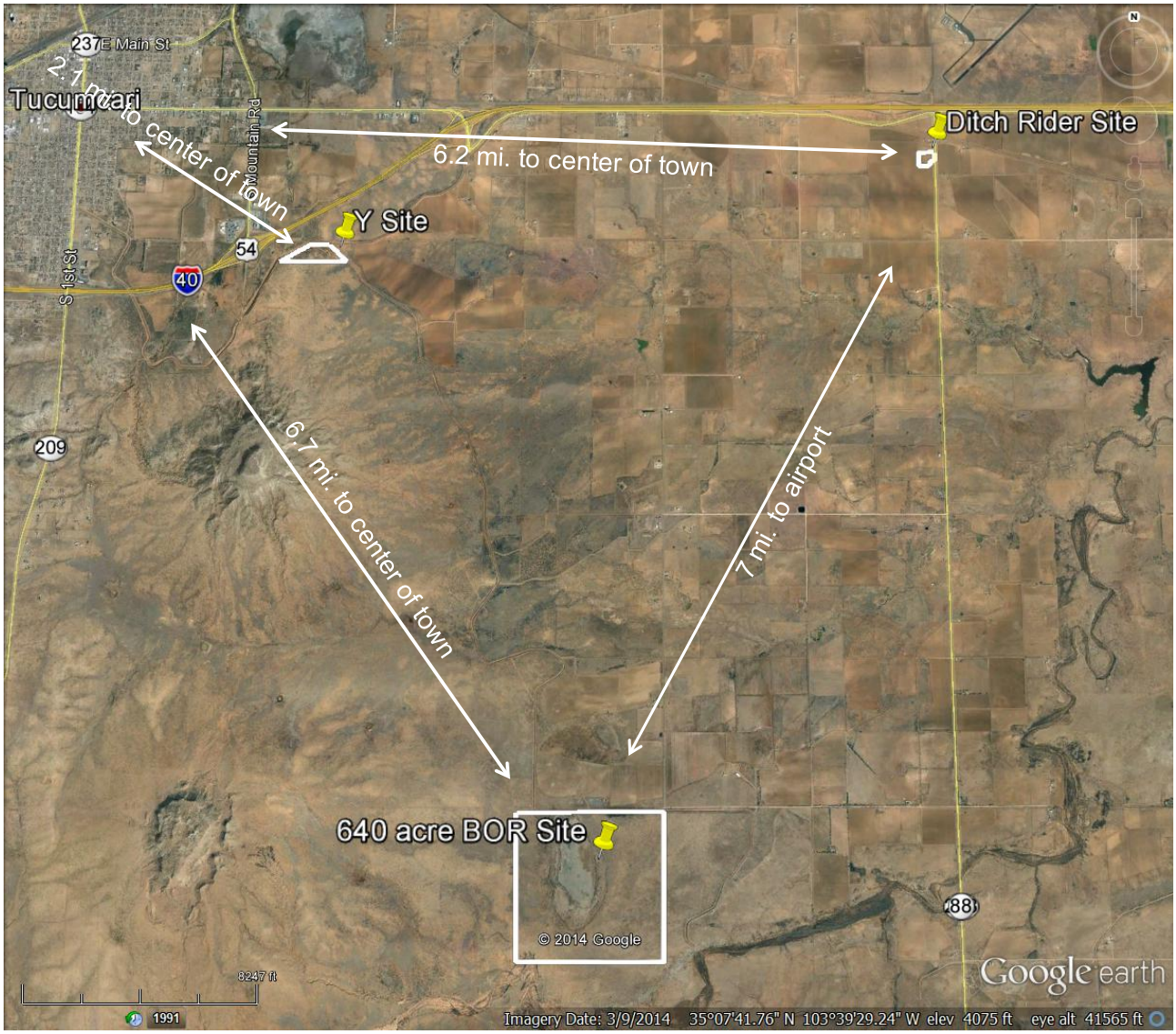


Figure 14: An overview of the three sites considered for potential energy development shows the positions relative to the town of Tucumcari.

Figure 15: The "Y Site" location is close to the electrical substation but is unsuitable for energy development because it is periodically flooded by AHCD irrigation water.

Figure 16: The "Y Site" electrical substation is located near the canal.

The second location (the "BOR Site") is approximately seven miles south of the Tucumcari airport and consists of 640 acres of land. While this land is not directly under Arch Hurley's authority, the Bureau allows for usage and leasing of the land to other parties as with the other two sites. Wind may be the best technology option to consider for this site as the view-shed issue is mostly nullified by Tucumcari Mountain and the large expanse of land on the west side of the site seems optimal for such an installation. Some of the land is currently being leased to a cattle farmer so this must be considered if solar panels are to be installed. The six-mile distance to the Tucumcari airport could also be an issue for this site as relevant flight patterns must be determined as not to create a potentially dangerous glare for planes in the area. The cost of connecting to the Y Substation 4.4 miles away or installing a substation for connecting to a nearby 115 kV line must be considered for this site as well. While there are 640 acres available, the presence of a depressed playa area that is vulnerable to flooding towards the middle of the property leaves only half of land suitable for electricity generation purposes. Figure 17 shows the area being considered at the BOR Site. Figure 18 shows the projected supply of wind energy at the BOR Site.

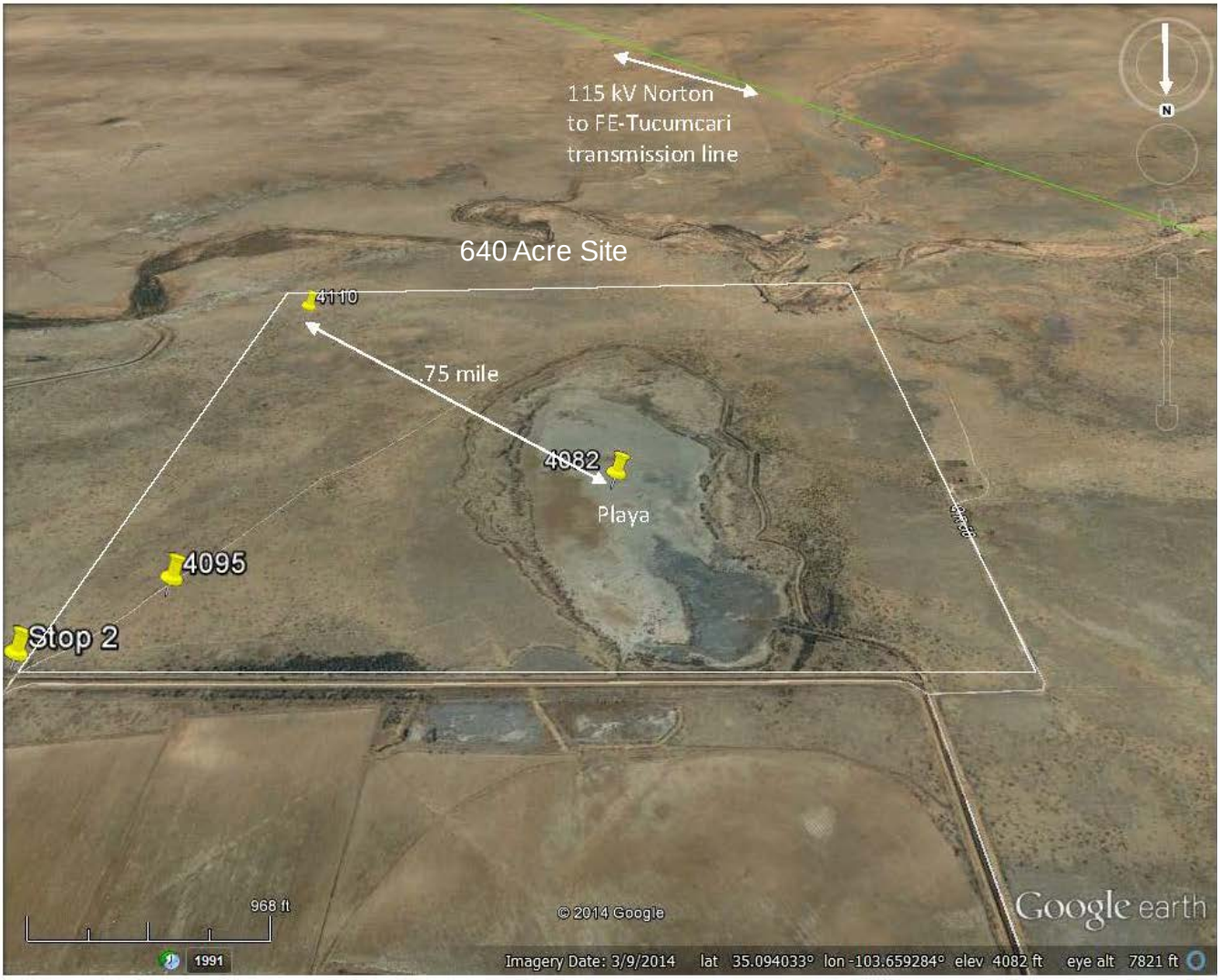


Figure 17: The "BOR Site" has 640 acres, some of which may be suitable for renewable energy development. (Note the reversal of direction.)

The last siting option is known as the "Ditch Rider Site." It is a flat, ten-acre parcel of land with a 4.4 mile distance to the Y Substation. The biggest drawback for the Ditch Rider site is its proximity to I-40 and the Tucumcari Airport. Wind sites are ruled out for this area and there are concerns about a solar array interfering with nearby flight patterns. Nevertheless, the site could be considered as a location for solar energy resources. Figure 19 shows an aerial view of the property and its relative closeness to I-40.

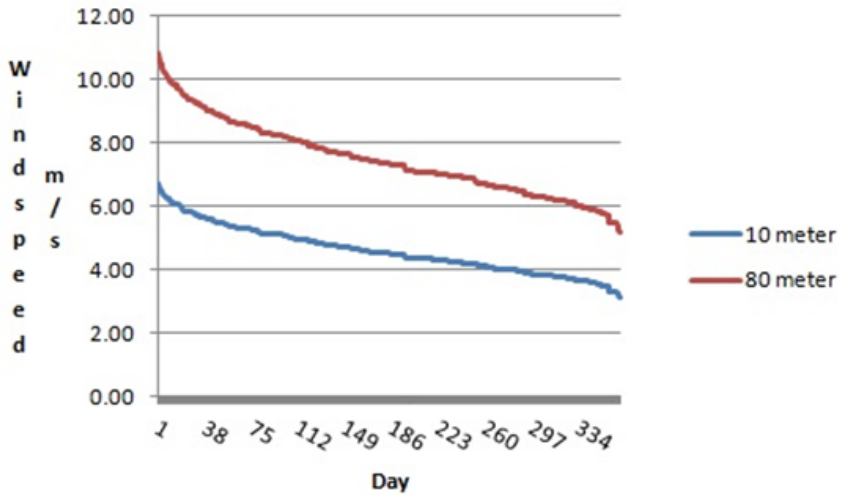


Figure 18: The projected supply of wind at the "BOR Site" shows an adequate resource level.

B. Analysis of Renewable Energy Options

Appendix A shows a detailed feasibility analysis of solar PV and wind energy development at the BOR site of 640 acres. A total electricity capacity of 10,580kW is assumed to be installed in two phases.

Figure 20 provides an overview of the proposed wind and solar development. The inset displays a view of the entire developable area which extends over 200 acres in a northern direction, offering construction grade terrain with 2 percent slope or less. At full build-out six wind turbines and a 40 acre solar array could be installed. Phase 1 would provide a maximum AC power rating of 7,500 kW using three wind turbines; Phase 2 provides a maximum AC power rating of 10,580kW by adding solar PV. Turbines numbered 1 to 3 would be installed first, and then solar arrays numbered 4. Remaining items marked *F* are for possible future development. The plant tie-in consists of a 69 kV tie-in station *STA 1*, connecting to a 115-69 kV step up station located 2.7 miles west of the site.

Figure 19: The Ditch Rider site has about ten acres of flat land that may be suitable for PV solar development.

A roll-up of key financial results from this analysis is shown in Table 5, tabulated as 20-year cumulative values. A possible interconnection within Farmers Electric Cooperative's (FEC's) system presents a potential hurdle, in terms of receiving a competitive buyback rate. The analysis

TABLE 5
Financial Results for BOR Site Development, over 20 Years

Construction Cost	Operating Expense	PPA $/MWh	Net Tax Expense	Revenue	Net Revenue to AHCD
($18,554,000)	($16,172,820)	45	($4,011,480)	$35,085,180	$1,290,610

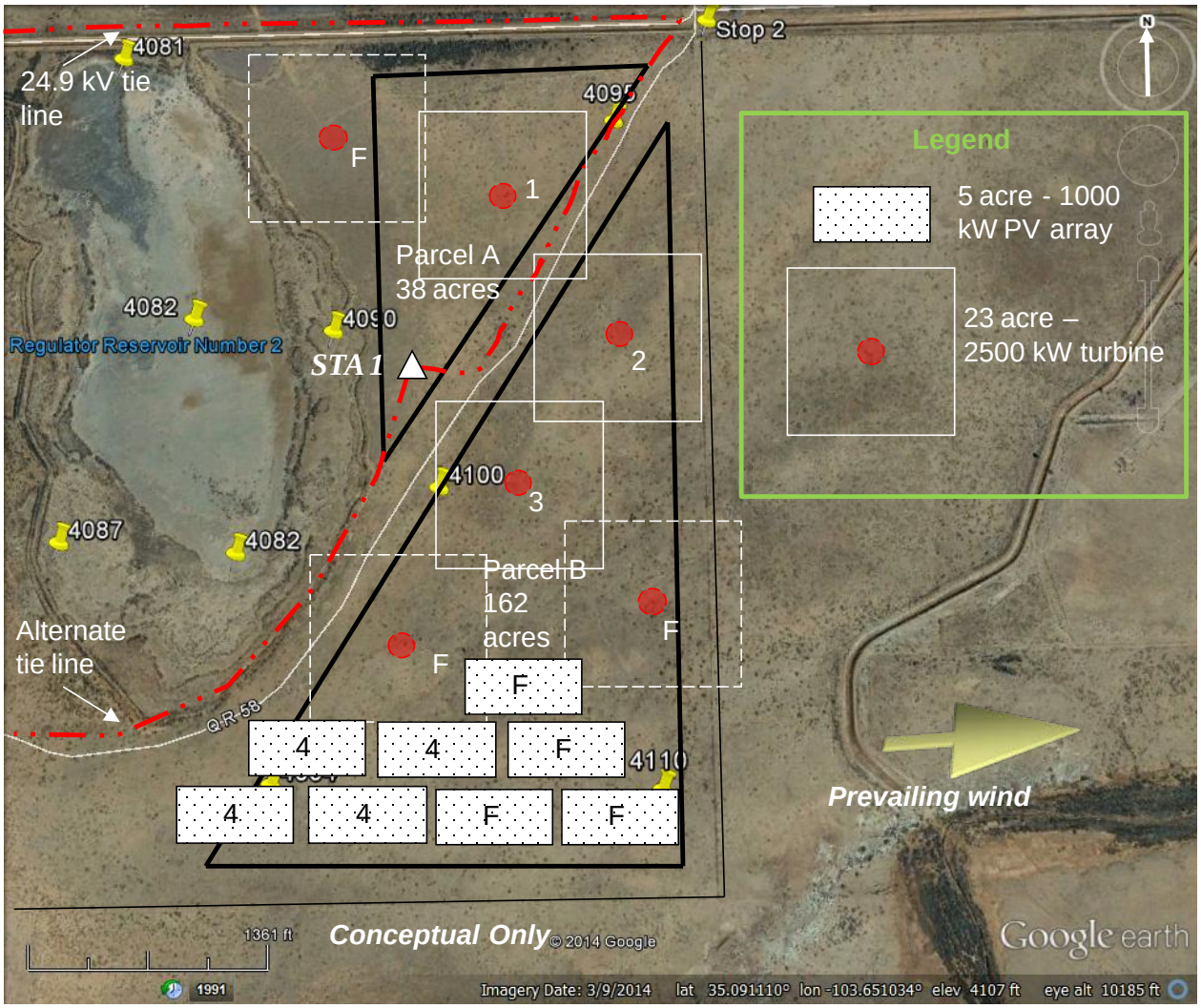


Figure 20: A conceptual plan to develop 10,580kW of electricity capacity using two phases is shown here. The scale is 1 inch to 775 feet. The red dots labeled "1, 2, and 3" in the squares show wind turbine locations built in phase 1, and rectangles labeled "4"are PV solar arrays for phase 2. Boxes labeled "F" are future activities

assumes a $45 per MWh power purchase agreement is negotiated (4.5 cents per kWh). A developer can economically produce power assuming 4.5 percent cost-of-money, all State and Federal tax benefits accrued, and royalty payment of 3 percent to AHCD. About $1.3M is available to AHCD over twenty years, or about $65k per year on average.

Significant unknowns are 1) FEC's ability to pay competitive buyback rates and 2) the near-term cost of solar cells which are dropping due to strong Chinese competition. If PV cell prices drop an additional 50 percent (which is possible in five to seven years), then the PPA required to achieve a 4.5 percent internal rate of return (IRR) drops to $40 per MWh. Royalty payment to AHCD also drops significantly. Generally, utilities in New Mexico will be reluctant to pay more

than retail energy rates for renewable power. FEC's current retail tariff rates are 8 cents per kWh for large "Power Service," 7.3 cents for Commercial service and 12 cents for Residential service.

It is possible that more revenues could be generated for AHCD. A best-case value might be as high as $3.9M over twenty years if several key feasibility factors were improved. First, a more intensive use of the BOR Site with a tighter turbine layout might increase electricity capacity by up to 50 percent. Second, it is possible that the typical 3 percent energy royalty and $150 per acre lease fee could be doubled, although this is rare in New Mexico. If these favorable factors were applied, the revenue stream to AHCD would $3.9M ($1.3M × 1.5 × 2).

C. Pipeline and Canal Lining

The Los Alamos team conducted rough calculations to size a pipe adequate for 300 cfs of flow in the 0.1-foot per 1000-foot gradient of the Main Canal. The model indicates an area of 129 sf in a rectangular box would be needed to handle the flow. This translates to a 13-foot diameter pipe, or dual ten-foot pipes each having 150 cfs in flow.[19] Such pipes are very expensive and generally not used in canal systems. As an example, northern New Jersey uses a pressurized aqueduct system with twin 6-foot diameter pipes to supply water to major metropolitan areas. Another option is to use a smaller pipeline. This would be less expensive but comes at the expense of a much smaller flow.

An alternative to the pipeline is to line the main canal with concrete to prevent infiltration. This mirrors what other aqueduct systems use (e.g., the California Aqueduct). A lined canal prevents infiltration, but does not prevent evaporation. A rough consideration of the relative contributions of these two factors to water loss is described below.

The 2006 NMSU report includes some field campaigns to quantify the seepage losses in the main canals for AHCD. They conducted an inflow-outflow study on a large section of the Conchas canal. The conclusion is that at a 145 cfs flow, about 30 cfs (20 percent) is lost, and at 300 cfs it is estimated that the loss would increase to about 34 cfs.

The inflow-outflow study actually quantifies all losses (infiltration and evaporation) by simply measuring the flow at point A and point B, with the difference is considered loss (called "seepage" in the report). However, some of that is evaporation. A quick quantification of the expected evaporative losses was done by Los Alamos. Conchas reservoir has an average pan evaporation measurement of 11.37 inches in the month of July.[20] Assuming that the evaporation variables are consistent from the reservoir to the distribution area (solar radiation, temperature, wind speed, etc.), this can be used as the rate of evaporation for any exposed body of water in the region. Using the expected surface water width in the canal at 300 cfs and over 30+ miles, the conversion indicates that just over 3 cfs is lost to evaporation in the canal by the time it travels from Conchas to the distribution area. In short, evaporative losses are much smaller than seepage losses and measurements indicate less than 30 percent total loss.

Although written almost a decade ago, the NMSU study provides costs for alternative canal improvement schemes that are relevant as comparisons. Three methods were considered: 1)

[19] David Judi, personal communication, October 9, 2014.
[20] http://www.wrcc.dri.edu/htmlfiles/westevap.final.html

concrete lining of the main Conchas canal, 2) concrete lining of lateral canals, and 3) installing a pipeline in the main Conchas canal. The relative costs of the three methods in terms of acre-foot saved show that lining laterals is about one-half the cost of lining the main canal. A 12-foot pipeline in the main canal was estimated to be five-times more costly than main canal lining, making this option cost-prohibitive.[21] Since our analysis shows only a small savings in evaporation, a pipeline cannot be considered a cost effective alternative for AHCD.

In terms of total costs, lining the main canal was expected to cost about $25M at 2005 prices, or about $2.1M per mile.[22] Laterals with a 3-foot depth and bottom width would costs about $41 per lineal foot, or $220k per mile.[23] Recognize these are 2005 prices, so current prices would be expected to be a factor of 1.22 higher using the CPI inflation rate.[24] This indicates a cost per mile of $2.6M for main canal lining and $270k per mile for laterals in 2014 dollars.

V. CONCLUSIONS AND RECOMMENDATIONS

The renewable energy project is estimated to return about $1.3M to AHCD over 20 years. This value is too small to finance a main canal lining or pipeline project, which would cost millions of dollars per mile. For a 20 year loan at seven percent interest, the $2.6M per mile canal lining cost would require payments of $242k per year.[25] The $65k annual revenues would cover only about one-third of a mile of lining. In the unlikely event that the best case revenue stream of $3.9M could be obtained, the $195k/y available could support almost one mile of main canal lining.

The revenue stream would be adequate to support improvements in the lateral canals, since the costs per section is the same order of magnitude as the average annual revenue stream, i.e., tens of thousands of dollars. Since the most cost-effective acre-foot savings is from lateral lining (per the NMSU study) and such projects are tractable in terms of revenue flow, it is recommended that prioritized projects of lateral improvements be pursued, perhaps via the NMSBA program.

[21] NMSU study, pp. 101-102.
[22] NMSU study, p. 101.
[23] NMSU study, p. 97.
[24] Bureau of Labor Statistics inflation calculator to convert 2005 dollar values to 2014; http://www.bls.gov/data/inflation_calculator.htm.
[25] Los Alamos National Bank calculator: $20,200/mo payments.

APPENDIX A: DETAILED FEASIBILITY ANALYSIS

Title:

AHCD RENEWABLE ENERGY ASSESSMENT

Author(s):
Energy Analysis Team/CCS-3, DSA-4

Intended for:
Arch Hurley Conservation District AHCD

Date: December 1, 2014

TABLE OF CONTENTS

1. Executive Summary

This report discusses the following conclusions related to renewable energy development at Arch Hurley (AHCD): first, the potential to capture, process, and deliver utility-grade renewable energy to FEC's electric grid equals or exceeds 10,580 Kilowatts capacity; second, AHCD's annual output capacity factor exceeds 35%; third, AHCD can deliver intermediate load quality energy to the grid and hour-to-hour output variability is reduced through installation of solar-wind arrays.

Table A-1 summarizes key conclusions, factors of importance, and references for reading.

Table A-1. Key Conclusions

Project Feature	Key Conclusion	Other Factors of Importance
Resource Assessment	Primary site Class 4 wind speeds; daily average 6.75 M/s, 90 days or more per year; 5.06 M/s, 180 days or more per year; Average monthly solar flux 7.37 kWh/m^2/day to 5.53 kWh/m^2/day	See Sections 3 and 4 for discussion.
Transmission Access	Single circuit 69 kV circuit feeder tied to FEC substation; Alternate 115-69 kV Collector	See Section 5 for discussion.
Project Phase-In Period	Two project phases are proposed: Phase 1 2014/15, 7,500 kW; Phase II 2015/16, 10,580 kW	See Section 5 for discussion.
Annual Energy Production	Phase 1 2014/15, 26,940MWh; Phase II 2015/16 5,400MWh	See Section 5 for discussion.
Busbar Energy Cost	Phase I, II: $45.0 per MWh[26]; confidence in key assumptions is significantly lower because of uncertainty in ITC, PTC status, SiC module pricing.	Assume 30% Federal ITC, 42%NM and Federal tax rate; $10 MWh REC sales; 4.5% IRR; See Section 5 for discussion.

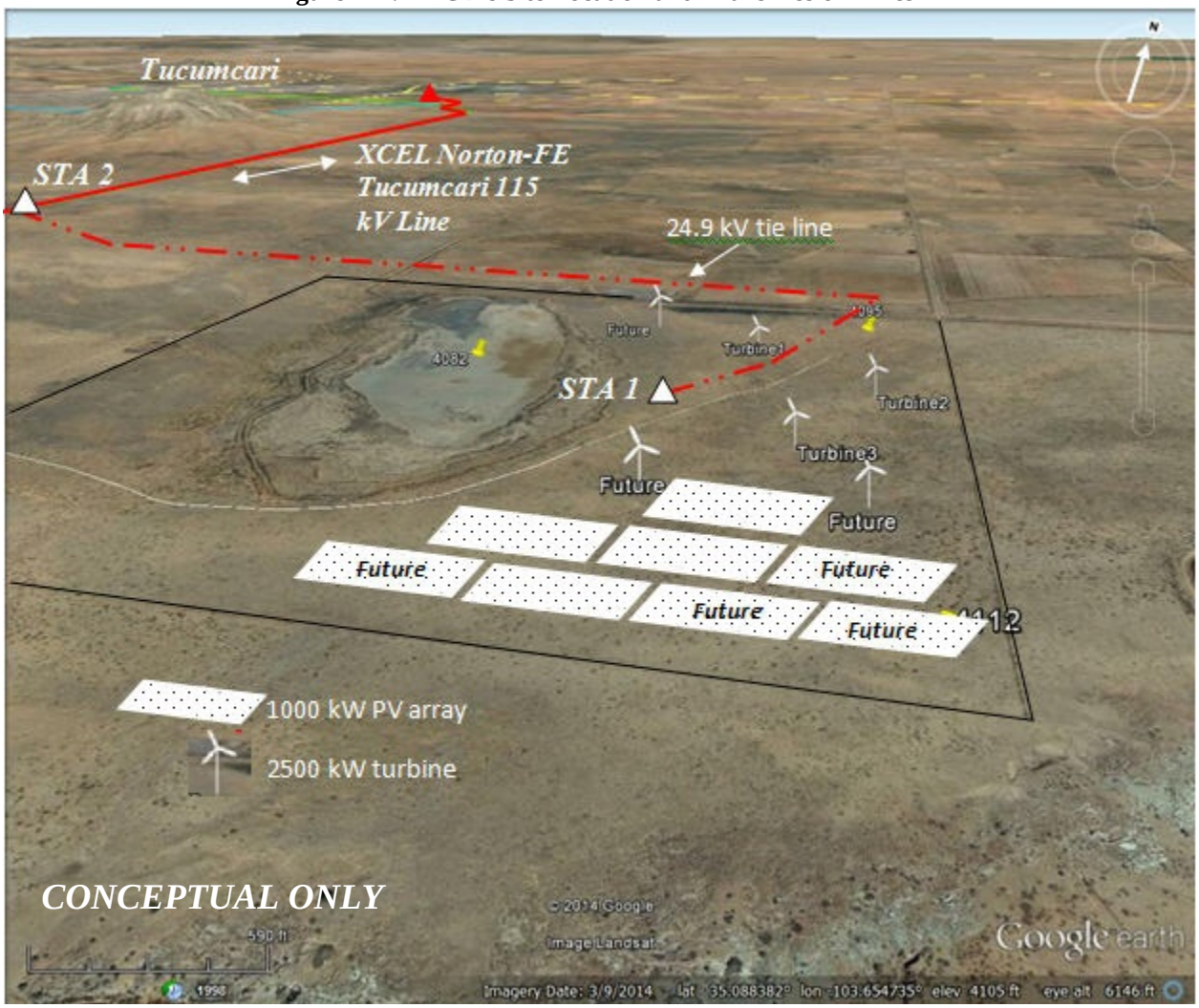
A summary of potential benefits for developers includes:

- Limited regulatory requirements affecting development in rural New Mexico
- No known occurrences of endangered species; suitable terrain for construction and operation
- Quay Rd AK/QR 58 provide construction grade access throughout property
- Near proximity to 115 kV transmission right-of-ways terminating at FE Tucumcari substation

AHCD consists of 200 acres of land located near Tucumcari, New Mexico. The boundary consists of multiple land parcels suitable for placement of utility-scale solar site development (see Figure A-1).

[26] For a discussion of issues related to electricity cost regulation and likely ranges for New Mexico's renewable portfolio standard (RPS) rates, see http://www.nmprc.state.nm.us/renewable.htm;

Figure A-1. AHCD's Site Location and Transmission Lines



Conclusions stated in this report are primarily based on ***Export metering options***. Export metering refers to no deduction of outflows from metered in flows, instead generators would be connected to deliver all output to the 115 kV distribution system. In this case, buyback rates would be negotiated with an off-system purchaser. Typically, Export metering electricity rates in New Mexico are lower than Net metering rates[27].

2. Goals and Objectives

This project was intended to accomplish the following goals and objectives:

- Evaluate potential for renewable electric generation at AHCD's renewable energy development sites.

[27] Market-based prices offered for comparison are: $85-120 per MWh for Net metering, $45-65 per MWh for Export metering.

- Estimate maximum capacity (MW) and energy (MWh) potential, based on readily available wind and solar data, topographic data and existing transmission line access.
- Create a phased build out plan which identifies exported (excess) electricity and revenue stream attributable to sale of excess electricity.
- Estimates to be based on published installed unit costs for wind and solar plants recently commissioned, average monthly capacity factors, and inferred resource variability.

This report is intended to serve as a notional evaluation of potential renewable development at AHCD's site. Key information used in LANL's analysis was supplied by the landowner, publicly available resource maps, subject matter expert judgment or other types of data relating to renewable development in general. None of the data utilized was obtained through site observation by LANL staff or metering at the site of interest. As a result, confidence in these findings is potentially lower than would be obtained from a feasibility study incorporating more detailed data gathering at the site. Further analysis will be needed to define a plant configuration which meets requirements of project developers. Ultimately, AHCD's wind and solar plants must generate reliable, utility-quality power by the most economic means possible. The results discussed in this report serve as an initial milestone in meeting those requirements.

The following Appendices are attached to this report:

- Appendix 1- Glossary of terms used
- Appendix 2- Financial Summary Sheets/References

3. AHCD 's Renewable Energy Resources

3.1 Wind Resources

AHCD offers potentially favorable wind resources to support operation of turbine arrays. For many hours of the year, this site can be classified as offering mid-range NREL Class 4 winds[28], with a substantial portion of hours during spring months possibly exceeding this level.

Daily averages of 6.75 M/s or greater are likely for 90 days or more per year. The estimated annual average wind speed at 80 meters hub height is estimated to equal or exceed 7.5 M/s. Turbulence U values have not been estimated, the degree to which wind energy can be effectively captured on the upper distribution still needs to be characterized. This data series additionally indicates wind direction in the vicinity of AHCD trends primarily along southeasterly to southwesterly azimuths at 270 degrees) with some scatter observed in transition months of June-July and October-November.

Yearly electric output produced by a 2,500 kW array is estimated to equal or exceed

[28] Class 4 or greater are generally considered to be suitable for most wind turbine applications. Class 3 areas are suitable for wind energy development using tall (e.g., 50 m hub height) turbines. Class 2 areas are marginal.

8,980 Mega-watt hours (MWh). Wind array performance is largely proportional to the wind energy received, which may vary from the long- term average by 30% monthly and 10% yearly. Energy production values are valid only for horizontal axis turbines.

3.2 Solar Resources

AHCD offers potential solar resources to support operation of solar photovoltaic arrays. This data series indicates that development sites capture on average from 5.53 kWh/m^2 per day in December to 115 kWh/m^2 per day in April. Annual average energy capture equals approximately 6.6 kWh/m^2 per day.

Yearly electric output produced by a 1,000 kW array is estimated to equal or exceed 1,750 Mega-watt hours (MWh). PV array performance is largely proportional to the solar radiation received, which may vary from the long- term average by 30% monthly and 10% yearly. Energy production values are valid only for non-tracking crystalline silicon PV panels.

4. AHCD Siting Issues

4.1 Wind Energy Conversion System (WECS)

In general, siting constraints imposed on larger WECS arrays include the following:

- Wind conditions (statistic data concerning wind speed and wind direction)
- Topography: the site needs to be favorable, preferably with an extensive crest line and associated swale geometry
- Accessibility (existing roads)
- Environmental influence of the turbine array (e.g. shadow flickering, noise emission, RF interference, visual impact, water requirement)
- Distances between the individual turbines in an array
- Adequate transmission capacity is needed to inject wind power from the plant to the grid
-

- **Table A-2. WECS Array Size Parameters**

Size Parameter	Plant: 1.6 MW Turbine	Plant: 2.0 MW Turbine
Total acres	66	75
Width E-W feet	3,030	3,230
Length N-S feet	760	810
No. Turbines	3 @5 rotor diameters	3 @ 5 rotor diameters
Daily output rating[29]	4.5 MW (10.8 MWh)	6.0 MW (14.4 MWh)
Water usage Gallons/year[30]	20,800	25,600

This assessment addresses only a subset of these issues. Building requirements, ownership and environmental issues must be addressed in detail by each developer before project commitments are made. The remaining issues are addressed in this assessment, to differing extents, in a

[29] Turbine capacity based on GE'S 1.6 MW 1.6-77 WTG turbine, cut-in loss of 7.4% and forced outage rate of 3%.
[30] Assumes four blade cleanings per year are required to maintain array efficiency.

preliminary manner. Table A-2 above shows the approximate surface of land needed for a three-turbine array. Two turbine sizes are listed for comparison, 1.6 MW and 2.0 MW which are mounted at hub heights of roughly 260 and 320 feet respectively.

For applications of this technology, turbines are sited at least four rotor diameters apart in the plane perpendicular to the prevailing wind direction, and at least six rotor diameters apart in the plane parallel to the prevailing wind direction. This prevents reduced wind speeds and increased turbulence due to adjacent turbines. Turbines are also placed at a distance twenty or more times the height of any man-made structure or vegetation upwind of the array. Turbulent wind flow created by a structure generally extends vertically to twice the height of the structure. It is important to avoid areas of steep slope. Wind on steep slopes tends to be turbulent and has a vertical component that can affect the turbine. Also, the construction costs for a steep slope are greatly increased. On ridgelines and hilltops, turbines are setback from the edge to avoid the impacts of the vertical component of the wind.

4.2 Solar Photovoltaic System (Solar PV)

In general, siting constraints imposed on larger solar PV arrays include the following:

- Solar conditions (statistic data concerning daily and seasonal insolation)
- Topography: the site needs to be favorable, preferably unobstructed south facing location offering tilt equal to latitude minus 10 degrees as a good compromise tilt angle; Accessibility (existing roads)
- Avoid excessive wind loading; design for anchoring
- Environmental influence of the array (e.g. solar glare, grading and compaction of terrain, erosion, water requirement)
- Spacing the rows of solar panels to maximize energy harvest while preventing shading; inter-row separation should be about 2.5 times the row height
- Adequate transmission capacity is needed to inject solar power from the plant to the grid

This assessment addresses only a subset of these issues. Table A-3 below shows the approximate surface of land needed for 1,000 and 4,000 kW PV array construction.

Table A-3. Solar PV Array Size Parameters

Size Parameter	Plant: 1.0 MW Array	Plant: 4.0 MW Array
Total acres	5.0	20.0
Width E-W feet	470	930
Length N-S feet	470	930
No. Racks/Panels[31]	750/4,500	3,000/18,000
Daily output rating	0.8 MW (4.6 MWh)	3.1 MW (18.5 MWh)
Water usage Cubic Feet/year[32]	1,900	7,600

[31] Rack capacity based on Kyocera KD 200-60 F panels, 1.44 kW with 6 panels per rack.
[32] Assumes three panel cleanings per year are required to maintain array efficiency; 1,000 US gallons equals 113.7 cubic feet. A 4 MW array will require approximately 7,600 cubic feet of water per year for cleaning.

A major design trade off relates to fixed versus tracking systems. The benefits of trackers vary between the different categories (one-axis, 1.5-axis, and dual-axis). Increased energy capture must exceed the added cost of installing and maintaining trackers over the lifetime of the system. An additional factor to be considered in the decision to use trackers or fixed systems is land use; tracking systems tend to use additional land[33].In general the added economic benefits are relatively marginal compared to increased complexity and maintenance. For applications of this technology, a number of siting variables must be considered. Best practice dictates that boreholes or trial pits are used to assess ground water level; resistivity, load-bearing properties, pH and chemical constituents of the soil in order to assess the degree of corrosion protection required. The site should be in a secure location where there is little risk of damage from either people or wildlife. It should ideally be in a location where security and maintenance personnel can respond quickly to any issue and this requirement should be stipulated in the maintenance contract.

4.3 Renewable Siting Options at AHCD

Table A-4 summarizes the criteria values and feasibility ratings assigned to Solar PV and WECS siting.

Table A-4. Renewable Site Ratings

Criteria	Project Phase 1	Project Phase 2
Resource Conditions	Average energy capture of 6.6 xx; peak capture exceeds 7.37 xx	
Topography	Unobstructed south facing location; entry at road Quay Rd AK/QR 58	Unobstructed south facing location; entry at road Quay Rd AK/QR 58
Wind loading	Typically less than 6.75M/s (solar arrays only)	
Environmental influence	Potential minor erosion; construction grade terrain with 2% slope or less	
Acreage	75 or more developable acres	20 or more developable acres
Transmission capacity	115 kV transmission line; back flow is technically feasible	115 kV transmission line; back flow is technically feasible
Overall site rating	Favorable	Favorable

Criteria discussed in Section 4.1 were evaluated separately for all potential sites, in terms of possible solar siting options. The rating scale (Favorable, Marginal, Unfavorable) is intended to serve as a preliminary measure of feasibility only. Array lay downs were evaluated for two phases. Sites at AHCD received a “Favorable” feasibility rating, based on the six siting criteria. Differences in terrain and resources are the major factors to be considered in choosing sites for development. N

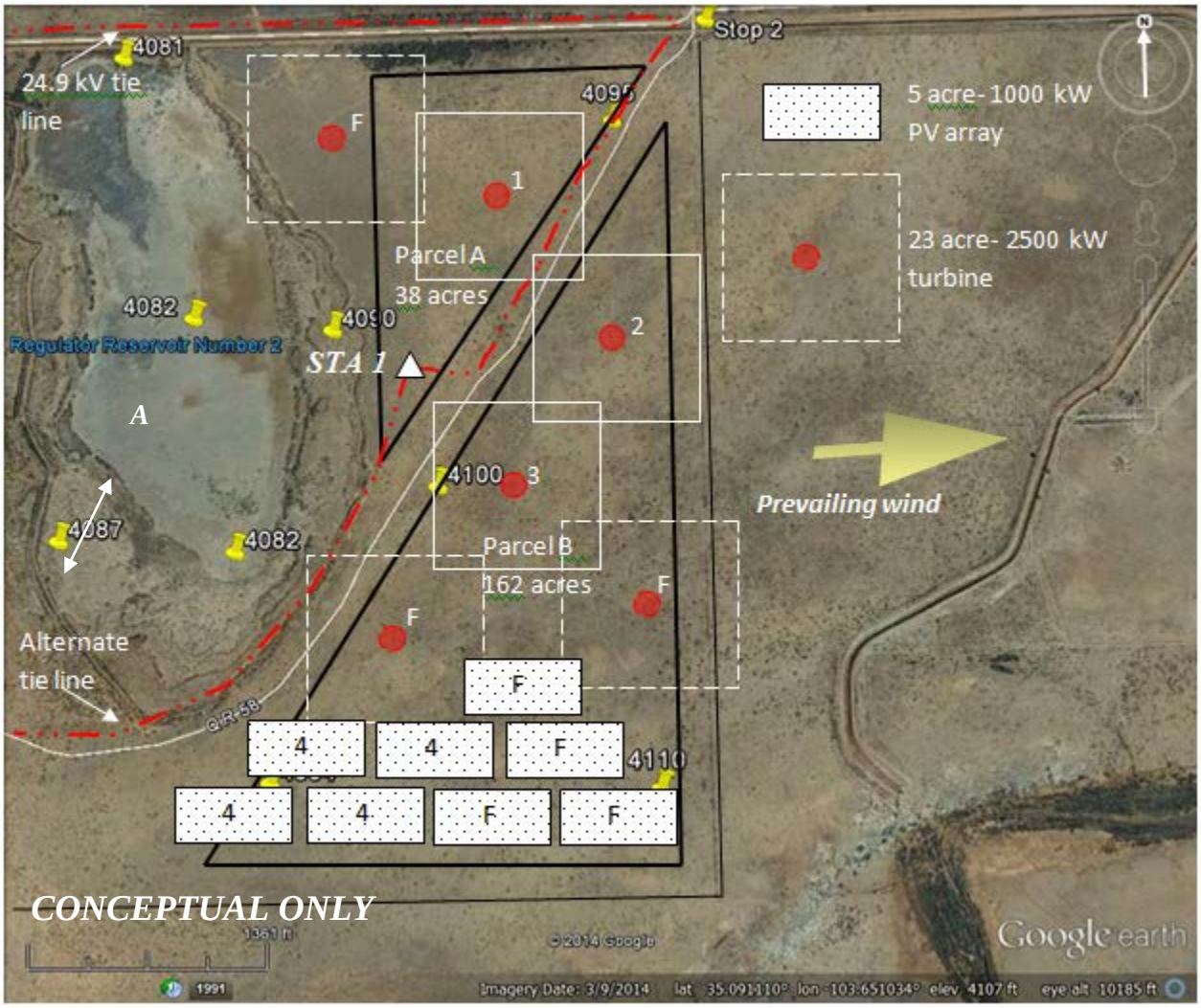
Section 4.3.1 displays a notional graphic overview of the proposed plant.

[33] Single-axis tracking systems will require 4 to 7 acres per megawatt to be developed.

4.3.1 10,580 kW Site Development

Figure A-4 provides an overview of the proposed WindSolar array.

Figure A-4. WindSolar Array; scale: 1 inch equals 775 feet



The inset displays a view of the entire developable area which extends over 200 acres in a northern direction, offering construction grade terrain with 2% slope or less. At full build out six wind turbines and a 40 acre solar array would be installed. Phase 1 would provide a maximum AC power rating of 7,500 kW; Phase 2 provides a maximum AC power rating of 10,580 kW. Turbines numbered 1-3 would be installed first, then solar arrays numbered 4, then remaining items marked F (future).

The plant tie-in consists of a 69 kV tie-in station STA 1, connecting to a 115-69 kV step up station located 2.7 line miles west of the site (marked STA 2 in Figure A-1).

5. Transmission Access and Development Phases

5.1 Transmission/Distribution Tie-in Options

AHCD offers ready access to transmission and sub-transmission line corridors in New Mexico (within the FEC service area). The 115 kV line operates with a capacity of approximately 20,000 kW. For the purposes of this study, one Export metering station is assumed to interconnect the FEC line.

The main features of each interconnection are as follows: The interconnect cost of a 10,580 kW array on existing poles would equal or exceed approximately $3,970,000 (Ref 5). Alternate line configurations may result in lower cost than stated above, these options should be investigated during initial discussions with potential developers. A utility interconnect study must be performed to accurately estimate path ratings under a variety of power flow conditions.

5.2 Development Phases

Based on time required to complete pre-construction activity such as site preparation, construction and other commissioning tasks, a proposed project timeline is shown in Table A-5.

Table A-5. AHCD's Project Development Phases

Phase 1- 2014/15 Total installed capacity: 7,500 kW Energy Sale MWh: 26,940 **Phase 2- 2015/16** Total installed capacity: 10,580 kW Energy Sale MWh: 32,340

The schedule shown in Table A-5 is offered for the purpose of early-phase project planning only. Additional technical detail will be required to completely define AHCD's plant configuration and timing of construction.

The proposed project consists of two phases, with fractions of added capacity listed for each project milestone (units are Megawatts MW or Megawatt-hours MWh). Gas-fired firming capacity may be required to supplement periods of low output and improve daily capacity factors. Estimated plant output is listed in the row labeled Energy Sale which includes both primary energy captured by both sites. All values are listed as cumulative quantities over successive project phases.

5.3 Estimated Project ROI and PPA Pricing

Two key quantities are chosen to estimate project return on investment (ROI): PPA (Power Purchase Agreement) purchase price and cost of money plus return.[18] PPA equals the delivered busbar energy price of renewable energy. Utilities in New Mexico are currently capped by NM PRC (New Mexico Public Regulatory Commission) rules at Reasonable Cost Threshold (RCT)

for purchases made under Renewable Portfolio Standard (RPS) rules, so this factor should be considered[34].

It is possible to negotiate higher PPAs but the market is likely to be unavailable the foreseeable future. The Federal Investment Tax Credit will expire in 2016, introducing uncertainty in tax calculations. Also, projecting utility buyback rates beyond this year introduces more uncertainty. Project assumptions utilized to estimate project Return-on-Investment or IRR include the following sets of factors: Financial, Operating and Construction Schedule. Key financial issues which affect the validity of these results are also discussed under "Key Financial Issues", Appendix 2. All results described in section 5.3.1 consider each siting option separately as a standalone project.

5.3.1 Project Financial Summary- Standalone Options

A roll-up of key financial results from this analysis is shown in Table A-6, tabulated as 20-year cumulative values.

Table A-6. AHCD's Key Financial Results- Standalone

Siting Option	Construction Cost	Operating Expenses	Revenue	Net Taxes	Payment to AHCD	PPA $/MWh
Primary site WindSolar 10,580 kW	($18,554,000)	($16,172,820)	$35,085,180	$4,011,480	($1,290,610)	45.0

A possible interconnection within FEC's system presents a potential hurdle, in terms of receiving a competitive buyback rate. A developer can economically produce power assuming 4.5% cost of money, all State and Federal tax benefits accrued and royalty payment of 3% to AHCD.

Significant unknowns are: FEC's ability to pay competitive buyback rates and the near-term cost of solar cells which are dropping due to strong Chinese competition If cell prices drop an additional 50% (which is possible in 5-7 years), then the required PPA price drops to $40/MWh. Royalty payment to AHCD also drops significantly. Generally, utilities in New Mexico will be reluctant to pay more than retail energy rates for renewable power. FEC's current retail tariff rates are 8 cents per kWh for large "Power Service", 7.3 cents for Commercial service and 12 cents for Residential service.

[34] "New Mexico's Renewable Energy PTC (NMAC 3.13.19.10) is fully subscribed for both wind and solar at this time, there is a separate queue each for wind and solar, with waiting lists now in place too." per Brian K Johnson, NM EMNRD email dated Oct 16, 2013.

APPENDIX 1: GLOSSARY OF TERMS USED

CF:	Capacity factor; A measure of plant output variability; equals the quantity (Average energy output/Peak energy output). Values are always between 0 and 1.
EIA	Energy Information Administration source of national-level statistics regarding cost and usage of electricity.
IRR:	Internal rate of return IRR of an investment is the interest rate at which the costs of the investment lead to the benefits of the investment. All gains are inherent to the time value of money, the investment has a zero net present value at this interest rate.
ITC:	Investment Tax Credit reduces federal income taxes for qualified tax-paying owners based on capital investment in renewable energy projects.
MVAR, KVAR	Megavolt- or Kilovolt-amperes reactive; reactive power exists in an AC circuit when the current and voltage are not in phase.
LANL	Primary author of this report.
MW:	Megawatt; a measure of instantaneous electric demand; a megawatt of capacity will produce electricity that equates to about the same amount of electricity consumed by 150 to 200 New Mexico homes in a year.
MWh:	Megawatt-hours, a measure of energy consumed over a specific period of time; calculated as the sum of all energy consumed during the billing period usually a month.
FEC	Farmers Electric Cooperative, a Clovis NM based rural electric provider.
PPA	Purchase Power Agreement.
PTC:	Production tax credit offered by either state or Federal governments.
PV	Photovoltaic (solar cell)
SiC	Silicon crystalline solar module, a typical design used in larger arrays.
WECS:	Wind energy conversion system, a common acronym for WECS.

APPENDIX 2: FINANCIAL SUMMARY SHEETS/REFERENCES

Project: Primary site WindSolar Array 10,580 kW Financial factors:

- Project financial assessment extends from 2015 to 2035 (20 years)
- Federal tax rate 37%; New Mexico tax rate 5%
- Investment Tax Credit 30% available until 2016
- Federal, New Mexico Production Tax Credit $0 per MWh
- New Mexico Capital Tax Credit 6% up to $60 million
- 5-Year straight line depreciation on plant

Operations and Maintenance O&M cost $8.8 per MWh

- Project is organized as a flow-through entity for tax purposes[35]

Operating factors

- Rated plant capacity at minimum 35% or higher daily capacity factor guaranteed from 10:00 am to 3:00 pm daily
- Energy sales of 5,400 MWh annually

AHCD's project analysis resulted in the following conclusions:

- Construction costs will equal or exceed $18,554,000 (Ref. 1) with additional operating expenses of $16,172,820 ex depreciation (Ref. 1, 3)
- Estimated revenue is $35,085,180 gross (before Federal and NM tax)
- Taxable income, after expenses and depreciation, is estimated to be $4,011,480
- Federal and state taxes levied will total $777,360 however, due to federal and state tax benefits for renewable resource production, the project will receive an estimated $4,011,480 in tax credits
- Cumulative royalty/lease payment to AHCD is estimated be $1,290,610; assumes 3% royalty rate and $150 per acre lease fee
- $45.0 per MWh PPA contract price with no escalation yields an IRR equal to 4.5%

Key Financial Issues:

- SiC module prices may fall dramatically through 2020 [Ref 2]. This study assumes a value of $2.36 per peak watt or 38% lower than reported by EIA in 2012 (Ref. 1,4). Prices of $1.17 per peak watt are achievable if DOE's 2020 Sunshot program goals are met.
- This site was classified as a NREL Class 4 wind regime with undetermined wind loss or acceleration along the AHCD boundary. A modest 5% increase in capacity factor could result in 15% additional energy capture.
- The likely range of O&M costs are also an important issue; at AHCD this value yields an equivalent cost of $ 8.8 per MWh, or approximately $808,641 per year.

[35] Such as LLC, LLP, etc. In this case investors will use the flow-through losses and credits against other income. For example, if Google became an investor in the project other corporate income would offset potential tax losses and credits from renewable energy projects.

References

1. "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants" US DOE Energy Information Administration, April 2013

2. "Residential, Commercial, and Utility-Scale Photovoltaic (PV) System Prices in the United States: Current Drivers and Cost-Reduction Opportunities" Goodrich et al, National Renewable Energy Laboratory, NREL/TP-6A20-53347, 2012.

3. "PV O&M Best Practices", N. Enbar NREL Utility/Lab Workshop on PV Technology and Systems, Tempe AZ Nov. 2010.

4. See http://www.sandc.com/news/index.php/2013/10/sc-to-design-and-build-4-1-mw-solar-project-in-massachusetts/

APPENDIX B: EXAMINING DISCOUNT RATES

When determining the feasibility of any long-term project, an inherent struggle lies with providing accurate representation of all associated costs and benefits. As a general rule, it is acknowledged that a dollar today is worth more than a dollar at some point in the future. For example, a dollar today can be saved in a bank, collecting interest virtually risk free over the project period. Due to this phenomenon, a discount rate must be applied to all future earnings and costs of a project to adjust to a present value. Present value is defined as the value, in today's dollars, of a sum of money to be received or paid at a specific date in the future.[36] The usage of discount rates and present value is a way of reflecting the opportunity costs associated with investing in a given project.

An area of concern regarding the AHCD Feasibility Report involves determining the discount rate that should be utilized for measuring the life-cycle benefits and costs of the project. This involves computation both for a screened renewable energy resource and the piping that Arch Hurley wants to install in its canal system. Discount rates reflect the time-value of money, and an accurate discount rate is essential for competent decision-making with regard to the long-term sustainability of the Tucumcari farming community. For governmental projects using government dollars, the Office of Management and Budget (OMB) provides guidelines for determining discount rates in OMB Circular A-94. Appendix C of this document provides the rates specified for cost-effectiveness projects, with the rate being based on real interest rates for Treasury Notes and Bonds. As listed in their system, a project with a 20-year life would use a real interest rate of 1.6 percent.[37]

While the usage of discount rates provided by the Circular A-94 is the best option for a government project, this does not necessarily work within the scope of the New Mexico Small Business Assistance Program, and more specifically, the Arch Hurley project. This is a quasi-governmental project that relies heavily on investment and effort on behalf of a private developer for fruition. Using Circular A-94 would be a mistake that could potentially overstate the viability of the project due to low discount rates that might not reflect the true long-term costs of the project. In that case, it is important to look at the components of the discount rate used within the industry and understand why this differs from the rates given by the OMB.

In the most basic economic sense, discount rates are quite simple. These rates are usually tied directly to prevailing interest rates, as the usefulness of a discount rate relies on showing what money is lost by not investing in a risk-free savings situation. Anyone intending to use a discount rate for a project must also decide whether to consider inflation by using nominal terms or adjusting for a constant "real" dollar. To mix usage of the two types of rates would create inaccurate results that would not be useful to the underlying objectives. In Edward Gramlich's, "A Guide to Cost Benefit Analysis," the author further elaborates on the simplicity of finding present value by strongly advising that risk must not be included in the discount rate.[38] His rationale assumes that risk is accounted for by other means, namely the usage of certainty

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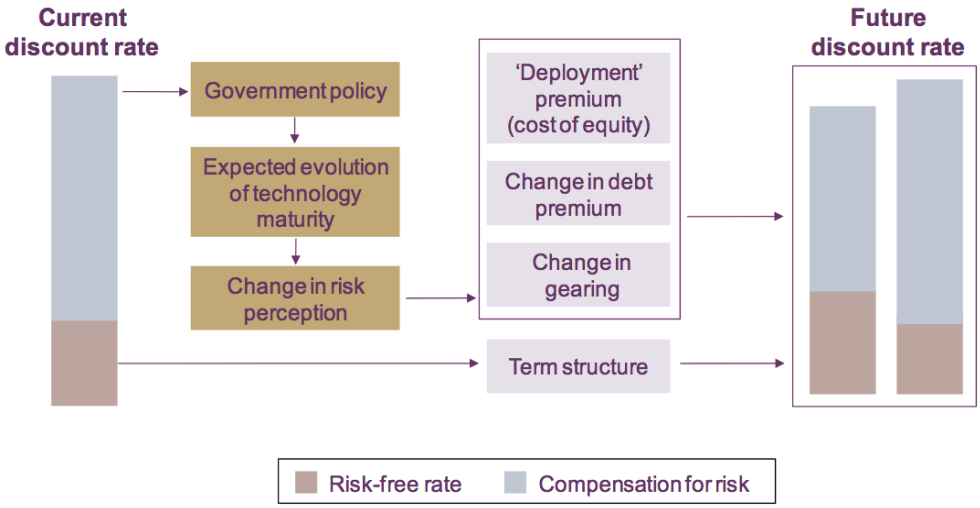
[36] Hall, Robert E.; Francfort, Lieberman Marc. *Microeconomics: Principles and Applications.* United States: South-Western, 2003.
[37] http://www.whitehouse.gov/omb/circulars_a094/a94_appx-c/
[38] Gramlich, Edward M. *A Guide to Benefit-Cost Analysis.* Englewood Cliffs: Prentice-Hall, Inc., 1990. p. 98-99.

equivalent income. After making this adjustment, utilizing a risk premium in the discount rate would amount to double-counting. An older, introductory work on cost-benefit analysis by E.J. Mishan similarly advocates looking into either certainty equivalence or dependable probabilities for decision making as opposed to adding any additional risk to the discount rate.[39]

While Gramlich provides a reasonable theoretical argument for not including a risk premium in the prevailing discount rate, his philosophy does not reflect the methodology within the present renewable energy market. Finding certainty equivalent incomes for projects is a fairly difficult process to gauge objectively, whereas making general assumptions about the uncertainty of future revenue streams seems to have become the adopted strategy among developers in the industry. When looking for industry averages, the prevailing opinion seems to be that a rate of 7 to 9 percent most accurately reflects the necessary discounting scheme.[40] This value is far higher than the OMB value of 1.6 percent given for a similar government-related project, and this discrepancy mainly reflects the renewable wind industry's risk assumptions and expertise relating to the subject.



Source: Oxera, "Discount Rates for Low-Carbon and Renewable Generation Technologies," Table 4.1, p. 21

Figure B-1: Discount rates for low-carbon and renewable energy markets showing portions for risk compensation.

[39] Mishan, E.J. *Cost-Benefit Analysis: New and Expanded Edition*. New York: Praeger Publishers, 1976. Pg 337.
[40] Oxera, "Discount Rates for Low-Carbon and Renewable Generation Technologies," Table 4.1, p. 21

The image in Figure B-1 reflects the composition of discount rates when relating to low carbon and renewable energy markets.[41] One easier way of looking at why high compensation for risk is implemented is to define the discount rate as a "hurdle rate," i.e., a rate used by developers to down-select alternative investments. Although these rates may not be entirely accurate and have certain biases towards lower-than-expected cash flows, they serve as an effective hurdle during the implementation stages of a project. A project must have positive net cash flow using the hurdle rate; otherwise it will signal investors not to engage in the project. In essence, the market determines the rate as a means of best reflecting all the potential risks of a project combined with present-value discounting. Furthermore, the addition of risk premiums to normal risk-free rates consistently occurs across a variety of technologies. See Table B-1.[42]

TABLE B-1
Discount Rates Across Technology Types

		Discount rate (real, pre-tax) (%)	
Technology	**Risk perception**	**Low**	**High**
Conventional generation			
CCGT	Low	6	9
Low-carbon and renewable generation			
Hydro ROR	Low	6	9
Solar PV	Low	6	9
Dedicated biogas (AD)	Low	7	10
Onshore wind	Low	7	10
Biomass	Medium	9	13
Nuclear (new build)	Medium	9	13
Offshore wind	Medium	10	14
Wave (fixed)	Medium	10	14
Tidal stream	High	12	17
Tidal barrage	High	12	17
CCS, coal	High	12	17
CCS, gas	High	12	17
Wave (floating)	High	13	18

Source: Oxera Report for the Committee on Climate Change.

Note: CCGT stands for Combined Cycle Gas Turbine. These are turbines that use both gas and steam as power sources to increase efficiency. Hydro ROR stands for run-of-the-river hydroelectricity in which there is limited or no storage. This leaves the output subject to changes in seasonal flow and drought conditions. CCS stands for Carbon Capture and Sequestration. This is not an energy source; rather it is a method of containing the environmental hazards produced by gas and coal by injection excess carbon dioxide into a long-term storage area.

[41] Oxera, "Discount Rates for Low-Carbon and Renewable Generation Technologies," Table 4.3, p. 24
[42] Oxera, Table 4.1, p. 21

As can be seen, the main factor in determining the spread of potential real interest rates is almost entirely found by considering the risk perception of the technology. Technologies such as Hydro have been well-tested over time, thus having lower rates than newer and more experimental technologies such as carbon capture and sequestration (CCS). Carbon capture and sequestration is a fairly new long-term commercial process for containing excess CO_2 generated by coal and gas. This technology stores the unwanted waste gas in geologic formations and is promoted by government regulations, as it incurs extra costs for companies using the technology. Clearly, understanding the risks in a market is instrumental to developing a legitimate forecast of prospective revenue and costs from the project. Even though E.J. Mishan and Edward Gramlich's works on cost-benefit analysis may disagree with the approach to accounting for uncertainty, it is current industry standard and consequently is used in this NMSBA study as well.