

# Chefornak Mini-grid Business Case

**November 2017**

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## Abstract

A business case analysis was performed for the Village of Chefnak for an islanded mini-grid. The business case analysis evaluated the optimal mini-grid configuration from the technical analysis performed by the National Renewable Energy using HOMER. The optimal configuration adds an 800 kW wind plant with 650 kW of electric thermal stoves and a 300 kW battery. The project cost \$5.8 million. The direct cost of electricity would likely decline from \$0.41/kWh to \$0.30/kWh. The direct costs don't include administrative and distribution costs. The addition of the renewable resources and thermal electric stoves reduced total fuel consumption by more almost 80% or approximately 103,000 gallons. The reduction in cost provides an opportunity for Chefnak's utility, the Naterkaq Light Plant, to obtain financing through grants and loans to install renewable energy and reduce overall fuel consumption to the community.<sup>1</sup>

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<sup>1</sup> Jimenez, A. "Chefnak Energy Configuration Options: Energy Infrastructure Optimization to Reduce Fuel Cost and Dependence in Chefnak Alaska." National Renewable Energy Laboratory. NREL/TP-5000-70579

## Summary

As part of the Alaska Mini-grid Project (AMP), the National Renewable Energy Laboratory (NREL) conducted an analysis of potential renewable energy (RE) retrofit options for the Chefnak diesel mini-grid. HOMER, a mini-grid analysis tool developed by the NREL, was used to evaluate options that minimized the net present cost to the village and its utility. Those options were compared to the net present cost of current diesel generation and the thermal load of the village. The options included combinations of solar, wind, batteries, and included electric thermal stoves to use renewable electricity that would otherwise be spilled. The assumed life of the project was chosen as 20 years as this was the lifetime of the most expensive asset, the wind turbines. The lowest net present cost alternative became the basis for the business case analysis.

The lowest net present cost option added an 800 kW wind plant with 650 kW of electric thermal stoves and a 300 kW battery. The direct cost of electricity would be reduced from \$0.407/kWh to \$0.308/kWh<sup>2</sup> if provided by Naterkaq Light Plant, the municipal utility company rather than an energy services company. This assumes that the residents agree to have the electric thermal stoves installed and pay approximately \$0.092 /kWh hour for their usage. If residents don't agree to the installation of electric thermal stoves (which is unlikely), the direct cost of the electricity would rise to \$0.411/kWh or slightly higher than the current direct cost of electricity. The installation of the wind plant and battery reduces the amount of diesel fuel consumption from more than 129 thousand gallons per year to 26 thousand gallons, reducing total fuel consumption by 103 thousand gallons for Chefnak, or almost 80%. If residents don't agree to the installation of the electric thermal stoves, approximately 1.9 million kWh of renewable energy would be unutilized. Residents could afford to pay up to \$0.25/kWh for the electricity to power the electric thermal stoves based on 2017 prices and still break even on the cost of residential fuel oil.

The best case presented above was one of fifty-six mini-grid configurations that were evaluated including the no-change base case. The options evaluated combinations of wind, solar, hydro and batteries with and without electric thermal stoves. Electric thermal stoves are used to accommodate excess renewable energy when electric demand otherwise would not consume all the renewable generation. Given the uncertain availability of excess wind energy, these stoves are expected to act as a low-cost supplemental heating source to the existing oil- or biomass-fired heating. Solar and wind generation was evaluated from 100 to 1600 kW. Batteries were optimized based on the total system production and in some cases reached 400 kW. Hydro was excluded from the analysis because there were no nearby feasible sites. Solar PV was considered, but never contained in the least cost set of mini-grid components because it was not cost effective.<sup>3</sup>

The diesel generation capacity at the village is currently 921 kW provided by two 371 kW and one 179 kW diesel generators. Each alternative generation option adds more renewable resources to the baseline, reducing the amount of diesel fuel and heating oil required to meet electricity and heating needs, (respectively), up until the capacity of the village electricity demand is met.

The selected 800 kW wind system with batteries, converters and electric thermal stoves costs \$5.8 million installed. The municipal utility is assumed to require a 4% rate of return on their investment, their weighted average cost of capital plus risk premium, whether the capital comes from equity, grants and/or loans. Municipal and cooperative entities need to recover the cost of debt which could be the municipal

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<sup>2</sup> The direct costs of electricity don't include any administrative or distribution costs. They contain only the costs of the fuel, O&M, and initial capital and replacement costs.

<sup>3</sup> Jimenez, A. "Chefnak Energy Configuration Options: Energy Infrastructure Optimization to Reduce Fuel Cost and Dependence in Chefnak Alaska." National Renewable Energy Laboratory. NREL/TP-5000-70579



bond market, bank for cooperatives, grants, or bank loans. The municipal market is based on the credit worthiness of the institution borrowing money. Small villages are unlikely to have a bond rating to provide a basis for repayment risk. They may be able to receive grants and government subsidized loans to add to their infrastructure to reduce diesel oil consumption.

The primary risk associated with adding renewable energy to the village is failure to repay any loans incurred to finance the mini-grid upgrade. Based on a review of the options available, the project will need to find a grant for a portion of the capital costs and debt for the remaining costs as it appears that grants no longer fully fund projects. In addition, regardless of how the village chooses to fund the project (as part of the Naterkaq Light Plant, a limited liability company or a contract with an energy services company (ESCO)), the electricity price risk falls primarily upon the customers of the company. They may face increased electricity rates should an unexpectedly large portion of the electricity be provided by the diesel generators instead of underperforming renewable generation. The increased diesel generation resulting from underperforming renewable generation will result in a higher variable cost of electricity. The PCE subsidy may ameliorate the risk as long as residential consumption doesn't rise above 500 kWh per household.

An ESCO reflects returns for a for-profit entity and brackets the upper end of the return required. ESCO operators would require at least a 7%-10% weighted average cost of capital. An ESCO would provide electricity as service to the village rather than using the local utility. The optimal facility and the capital required might be large enough to attract an outside entity. The price of electricity, given the 10% return hurdle rate, would require an approximate \$0.52-\$0.53/kWh, significantly above that of the local utility. In addition, there is some risk that the production tax credit (PTC) would expire by the time construction begins. The PTC for wind expires December 31, 2019. In addition, the PTC provides only 40% of the original \$0.023/kWh, or \$0.009 for 10 years for projects qualifying in 2019.<sup>4</sup>

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<sup>4</sup> DSIRE. 2016. "Renewable Electricity Production Tax Credit (PTC)." Last updated May 24, 2016. Accessed August 24, 2017 at <http://programs.dsireusa.org/system/program/detail/734>

## **Acknowledgments**

The authors would like to thank Virginia Fay of University of Alaska Anchorage's Institute of Social and Economic Research for her guidance and feedback in understanding the unique challenges of rural communities in Alaska.



## **Acronyms and Abbreviations**

AMP – Alaska Mini-grid Project  
CREBS – Clean Renewable Energy Bonds  
Elec – Electricity  
ESCO – Energy Services Company  
EPC – Engineering, Procurement and Construction  
FY – Fiscal year  
Gal – Gallon  
HOMER – Hybrid Renewable and Distributed Generation System  
ITC – Investment Tax Credit  
kW – kilowatt  
kWh – kilowatt hour  
MW – megawatt  
MWh – megawatt hour  
NEPA – National Environmental Protection Act  
O&M – Operations and maintenance  
RE – Renewable energy  
PTC – Production tax credit  
PV - Photovoltaic  
REAP – Rural Energy for America Program  
USDA – US Department of Agriculture  
USDOE – US Department of Energy



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## 1.0 Introduction

As part of the Alaska Mini-grid Project (AMP), the National Renewable Energy Laboratory (NREL) conducted an analysis of potential renewable energy (RE) retrofit options for the Chefnak diesel mini-grid. This paper provides the business case for the optimal solution undertaken by the technical team reviewing potential options for Chefnak. HOMER, a mini-grid analysis tool developed by the NREL, was used to evaluate options that minimized the net present cost to the village and its utility. The options were compared to the net present cost of current diesel generation and the thermal load of the village. The options evaluated included combinations of solar, wind, batteries, and electric thermal stoves to use renewable electricity that would otherwise be spilled. Electric thermal stoves allow excess renewable energy to be used when village electric demand is less than the renewable generation available. The lowest net present cost alternative became the basis for the business case.

Chefnak currently has three diesel generators with 921 kW of capacity. Thus, a mini-grid design consisting of adding wind, solar, batteries and thermal electric stoves was analyzed to reduce diesel fuel dependency. The lowest net present cost option adds an 800 kW wind plant with 650 kW of electric thermal stoves and a 300 kW battery and costs an approximate \$5.8 million.



## 2.0 Background

Chefornak is a rural village located in Bethel Borough in Southwest Alaska with a population of 442 in the 2016 (Figures 2-1 and 2-2).<sup>5</sup> Currently, Chefornak obtains all of its electricity through diesel-fueled generators. Most of the homes are not thoroughly insulated nor do they have energy-efficient appliances.

The village receives its electricity from three diesel generators whose combined capacity is 921 kW. Current diesel electricity generation provides 1.6 MWh per year to the community, and is assumed to rise 1.2% per year through the analysis time period. Peak electric demand for the year occurs in January at just over 300 kW. Diesel consumption for 2016 increased to 113,389 gallons<sup>6</sup> at an average price of \$4.14/gallon<sup>7</sup>, up from 81,366 gallons in 2008. The price in 2008 was significantly higher at \$7.89/gallon<sup>8</sup>. Residential housing is primarily heated by fuel oil. Low temperatures during the winter can reach as low as -34°C but with January averages of -14°C.

Electricity prices to the community appear to be priced using residential and commercial rates. The average rate, calculated across all kWh sold to all consumers, was \$0.66/kWh in 2016. The State of Alaska Power Cost Equalization (PCE) program attempts to lower the price of electricity in rural areas of Alaska based on electric rates in Anchorage, Fairbanks and Juneau. The program primarily offsets the price of energy for the first 500 kWh of electricity used per month for residential customers. Residential electricity consumers received a subsidy that reduced the effective price of electricity by \$0.26/kWh. The rate charged to residential consumers was \$0.49/kWh providing an effective rate of \$0.23/kWh. The nonfuel expenses were reported at \$0.31/kWh.<sup>9</sup>

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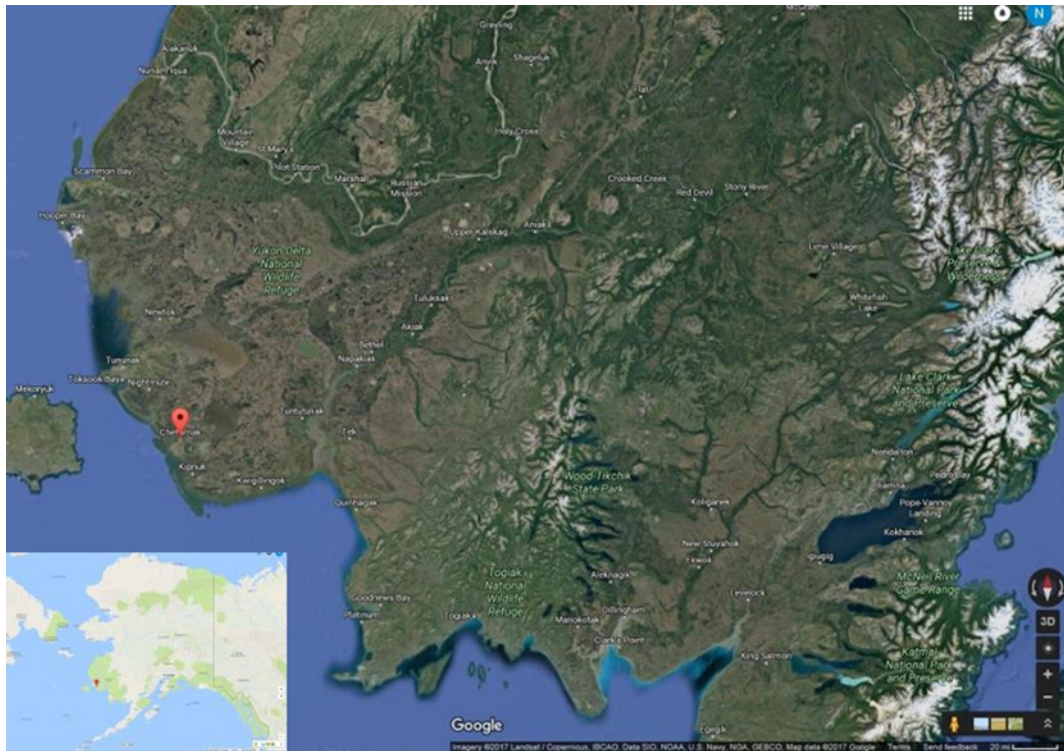
<sup>5</sup> State of Alaska Department of Labor and Workforce Development, Accessed October 4, 2017 at <http://live.laborstats.alaska.gov/pop/index.cfm>

<sup>6</sup> Alaska Energy Authority; Remote Alaska Communities Energy Efficiency Competition: Phase II Summary and Strategic Energy Efficiency Plan – Chefornak; 2016 Aug 19

<sup>7</sup> Alaska Energy Authority. 2017. Power Cost Equalization Program: Statistical Data by Community – Reporting Period: July 1, 2015 to June 30, 2016. Accessed at <http://www.akenergyauthority.org/Portals/0/DNNGalleryPro/uploads/2017/2/28/FY16PCEAnnualCommunity.pdf>

<sup>8</sup> Alaska.edu. Alaska Data Gateway – Community Data Summary: Chefornak. <https://akenergygateway.alaska.edu/community-data-summary/1400188/#detail-fuel>

<sup>9</sup> Alaska Energy Authority; FY 2012 – FY2016 Annual PCE Statistical Reports by Community. <http://www.akenergyauthority.org/Programs/PCE>



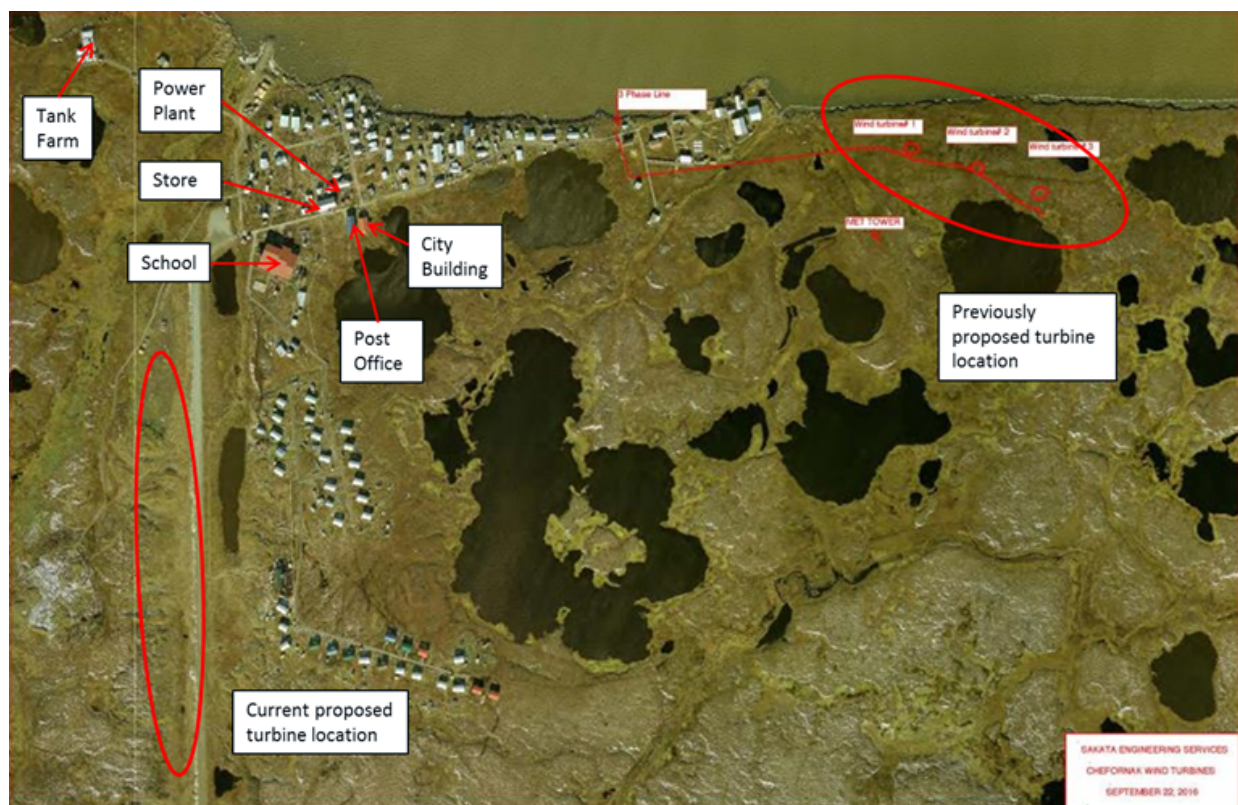
**Figure 2-1:** Regional map of Chefooak. Source: Google Maps

See Table 2-1 for diesel prices from FY2012-FY2016. The table also indicates the cost of electricity sold over the same period. In addition, note the high line losses at 31%-41% shown in 2012 and 2013. Powerhouse consumption is about 2.5% of production.

**Table 2-1:** PCE Statistics, 2012-2016<sup>10</sup>

Year (FY)	FY2012	FY2013	FY2014	FY2015	FY2016
Diesel cost (\$/gal.)	\$4.33	\$5.21	\$6.65	\$4.55	\$4.14
Diesel consumption (gal.)	131,728	132,248	116,999	117,529	113,389
Elec. cost (\$/kWh)	\$0.57	\$0.91	\$0.60	\$0.54	\$0.66
Elec Generation (MWh)	1,790	1,813	1,531	1,597	1,533
Elec Consumption (MWh)	1,197	1,026	1,288	1,433	1,355
Line loss (%)	31.1	40.8	13.4	7.9	9.1

<sup>10</sup> Ibid.



**Figure 2-2:** Aerial view of Cheforanak. Source: Google Maps



### 3.0 Project Objective

The Project retrofits the mini-grid for Chefnak composed of renewable energy resources including a mix of wind, batteries, and thermal stoves. The retrofit replaces electricity generated by existing diesel generators to reduce the dependence on expensive diesel-fuel generated electricity. Historically, diesel prices have risen to as high as \$7.89/gallon in 2008 and averaged \$6.41 over the last 10 years. The analysis assumed a \$4.50/gallon price for the diesel fuel for electricity generation. The project expects to reduce diesel fuel demand for electricity by 80% from estimated baseline levels due to the construction and installation of the renewable generation. The battery bank and converter are sized to cover lulls in the wind during diesel-off operation.

The project will also reduce the demand for heating oil through the use of electric thermal stoves that use surplus renewable energy (energy generated by renewable resources that exceeds the demand for electricity). Thermal electric stoves bought by the utility and leased to customers (only if they opt in) with low-cost renewable electricity may provide a greater return to the utility on renewable energy that would otherwise be spilled. In addition, proposed energy efficiency projects for buildings will reduce the demand for electricity and fuel oil reducing overall demand for diesel and heating oil. The business case only provides an analysis of the mini-grid resources developed for the village and assumes that any energy efficiency improvements are realized by other means and assumed to be completed prior to the beginning of the operation of the upgraded mini-grid. These upgrades provide a reduced thermal and electrical load on which the mini-grid operates over the project life. The technical project analysis evaluated renewable energy resources with and without the energy efficiency upgrades and the renewable energy and energy efficiency cases provided the lowest net present cost. The project expects to reduce the cost of electricity and improve environmental conditions through the use of renewable resources.<sup>11</sup>

The business case evaluated the feasibility of the municipal utility retrofitting their mini-grid with the renewable resources in this plan. The municipal utility has a multitude of incentives that can be used to improve the internal rate of return. In this analysis, the utility was assumed to obtain a grant for the equity portion and a loan from one of the funding agencies available to municipal entities. The following programs may provide funding: Alaska Native corporations, the Power Project Loan Fund, Renewable Energy Grant Program, Clean Renewable Energy Bonds (CREBS), and the USDA – Rural Energy for America Program (REAP) Grants. The Renewable Energy Grant from the Alaska Energy Authority (AEA) currently has received no new funding and has a waiting list so it may not be a possibility. An additional source of funds could be Native corporations. There is a growing number of renewable energy projects financed for the production tax credits.<sup>12</sup> However, tax equity availability could shrink as the production tax credit expires. In addition, tribal corporations may qualify for the Tribal Energy Grant Program.<sup>13</sup> In addition, if investment requirements are met, Chefnak's Naterkag Light Plant could potentially obtain financing through other alternatives such as the DOE loan guarantee program should they be able to meet the requirements of the program.

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<sup>11</sup> Jimenez, A. "Chefnak Energy Configuration Options: Energy Infrastructure Optimization to Reduce Fuel Cost and Dependence in Chefnak Alaska." National Renewable Energy Laboratory. NREL/TP-5000-70579

<sup>12</sup> Currently, production tax credits are scheduled to end December 31, 2019.

<sup>13</sup> See DSIRE at <http://programs.dsireusa.org/system/program/detail/918>

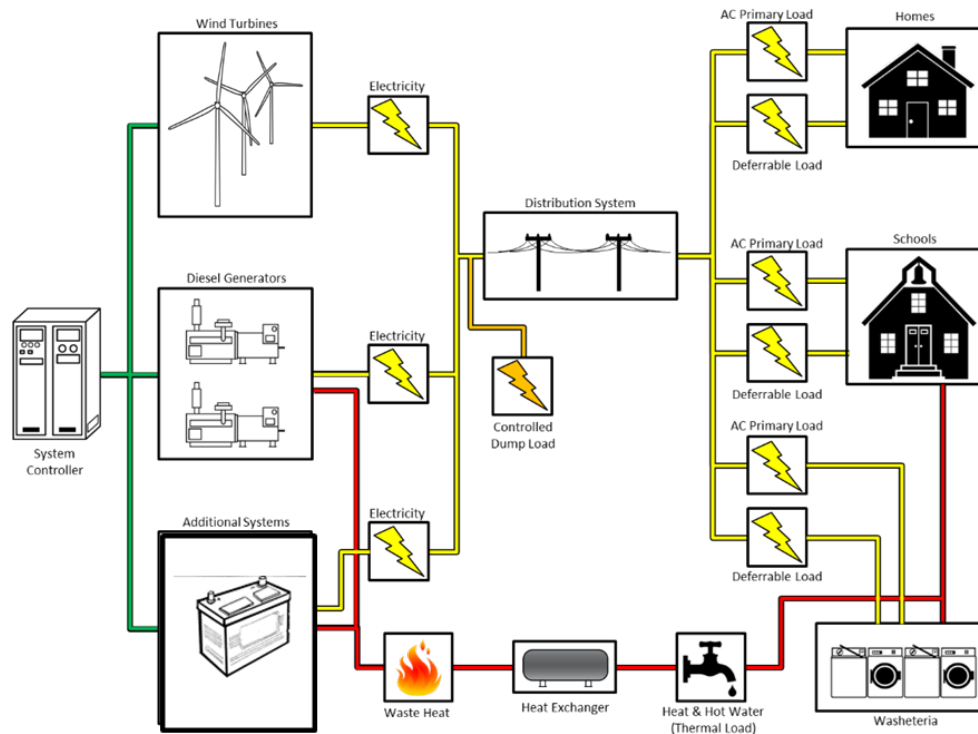




## 4.0 Project Description

The retrofitted mini-grid proposed includes 800 kW of wind combined with a 300 kW battery and 650 kW of electric thermal stoves (Figure 4-1). The assumed life of the project was chosen as 20 years as this was the lifetime of the most expensive asset, the wind turbines. The total cost of the proposed installed project is \$5.8 million, \$5 million of which covers 8 wind turbines. The project will also include the accompanying switchgears, controllers and software required to operate the mini-grid. The proposed option was the optimal configuration based on an analysis using HOMER and was selected from an array of options that included wind, solar, hydroelectricity, batteries and thermal stoves. The mini-grid retrofitted will supplement and reduce diesel consumption used in current generation by 103 thousand gallons per year.

The installed costs, operating costs and assumed lifetimes for each of the resources are shown in Table 4-1. The installed costs reflect the harsh climate in Alaska as well as the remoteness of the community. No values for diesel generators were included; any existing generation in the village was assumed to be new and are treated as sunk costs. However, the diesel generators are assumed to last 60,000-100,000 hours and due to their low usage in the optimal solutions, they were not replaced during the 20-year project lifetime. The renewable resources are expected to have a 20 year life with the exception of hydro which has a lifetime of 30 years. The assumptions are based on the baseline values in HOMER.



**Figure 4-1:** Project schematic of the mini-grid retrofit to be implemented

Fixed O&M costs for diesel generation are not avoidable while diesel fuel costs are avoidable. Note that some non-fuel O&M costs associated with the diesel are hourly, meaning that they are only incurred if the diesel generator is operating. Thus if diesel generation is to be maintained in the village, fixed O&M costs are required regardless of the extent to which the diesel operates, but hourly O&M and fuel charges change by the amount of time the diesel generation is operated. Similarly, O&M for renewables such as wind and solar are considered variable because they are still future costs and can't be avoided. They are also dependent on run-time hours.

**Table 4-1: Resources and assumptions used in the analysis**

	1	3	5	8
Wind Turbines (No. 100 kW)				
Installed Capital Cost (\$/Turbine)	900,000	731,667	670,000	628,750
O&M (\$/kW)	175	166	158	151
Lifetime (years)	20	20	20	20
Solar PV kW	100	300	500	800
Installed Capital Cost (\$/kW)	5,000	5,000	5,000	5,000
Solar PV O&M (\$/kW)	20	20	20	20
Lifetime (years)	20	20	20	20
Batteries (kW)	200	400		
Installed Capital Cost (\$)	190,000	382,000		
Battery Replacement Cost (\$)	142,000	178,500		
Batteries O&M (\$/year)	4,000	6,000		
Lifetime (Number of Cycles)	Number of years option dependent			
Converter capacity (kW)	160	320		
Converter Installed Costs (\$)	190,000	382,000		
Replacement Costs (\$)	142,000	178,000		
O&M (\$/year)	1,600	2,400		
Lifetime (years)	15	15		
Electric Thermal Stove Capacity (kW)	100	300	600	900
Installed Cost (\$)	60,000	160,000	310,000	460,000
Diesel 202 kW O&M (\$/hr)	15.64			
Diesel 202 kW fuel (\$/kWh)	0.316			
Diesel 371 kW O&M (\$/hr)	16.80			
Diesel 371 kW fuel (\$/kWh)	0.3622			

The characteristics of the batteries used in the analysis are shown in Table 4-2. Note the largest size is 100 kW / 100 kWh. The battery has a \$50,000 integration cost and then is estimated to cost \$700/kW for the first 200 kW and \$480/kW over 200 kW installed. The replacement costs are slightly lower with an initial cost of \$37,500 instead of 450,000. Converter upfront costs are similar. Replacement of the battery was assumed to be at end of year 10 while replacement of the converter was assumed to occur at the end of year 15. Normally battery life is cycle specific and thus not based on years.

**Table 4-2: Battery statistics by size**

<b>Item</b>	<b>Bat 100/100</b>	<b>Bat 50/50</b>	<b>Bat 10/10</b>
Cost	\$150,000	\$100,000	\$60,000
Operational Cost	\$0 Dollars/Hour	\$0 Dollars/Hour	\$0 Dollars/Hour
Charging Efficiencies	89.4%	100%	89%
Discharging Efficiencies	89.4%	100%	89%
Energy Capacity	100 kWh	50 kWh	10 kWh
Max Charge Rate	100 kW	50 kW	10 kW
Max Discharge Rate	100 kW	50 kW	10 kW
Min State of Charge	10%	10%	10%
Max State of Charge	90%	90%	90%
Desired State of Charge	0.7	0.7	0.7



## 5.0 Alternatives Studied

Fifty-six options were evaluated using HOMER<sup>14</sup> (see the technical report); a base case (existing diesel-only configuration) was created in order to create a baseline against which the diesel fuel consumption in the prospective mini-grid configurations could be compared. Each alternative also included an option on whether electric thermal stoves could be used as an alternative load for otherwise unneeded renewable energy. Additionally, evaluations were made with and without the assumptions of energy efficiency upgrades being made prior to the operational period of the mini-grid. In all evaluated scenarios the energy efficiency upgrades were found to be cost effective and thus were assumed to be completed.

The renewable alternatives evaluated the level of wind, the kW and kWh of battery, and the total installed capacity of the electric thermal stoves that minimized the net present cost. Alternatives for wind reached as high as 16 turbines. Battery capacity was evaluated between 100 and 400 kW, while thermal stoves were evaluated between 0 and 1400 kW. The number of electric thermal stoves that could be installed (assumed at 6 kW each) was limited by the estimated thermal load for the village. Hydro generation wasn't considered due to a lack of resource. Solar PV was considered but didn't enter any of the solution alternatives because they weren't economic. Hydro generation wasn't considered because there was no resource.

The diesel generation capacity at the village is currently 971 kW. The diesel generators use about 129 thousand gallons of fuel each year in the baseline analysis or about, 13.5 gallons per hour for each diesel. Each alternative generation option adds more renewable resources to the baseline, reducing the amount of diesel fuel and heating oil that are required to meet electricity and heating needs.

The option that provides the lowest net present cost to the village is an 800 kW wind facility with 300 kW of batteries and 650 kW of electric thermal stoves assuming a 4% discount rate. The 800 kW of wind turbines generate 3.2 million kWh, 1.9 million kWh per year of which are used by the 650 kW of electric thermal stoves with stoves being used whenever possible. If less stoves are leased, more wind will be spilled. This option reduces diesel fuel consumption by more than 80% and overall fuel consumption by 54% (Table 5-1). The 800 kW wind facility with batteries and thermal stoves was selected for displaying the sources and uses, income statement and cash flow *pro forma* for the Naterkaq Light Plant.

**Table 5-1:** Annual heating and diesel fuel expenditures in the Baseline and Optimal cases

	Baseline Case	Optimal Case
Total \$	\$1,802,000	\$859,000
Heating fuel	\$1,220,00	\$741,000
Diesel fuel	\$582,000	\$117,000

<sup>14</sup> Jimenez, T, et al. 2017. "Chefornak Minigrid Configuration Options." National Renewable Energy Laboratory, GMLC-XXXXX



## 6.0 Permitting

There may be wind and hazardous waste permitting issues for Chefornek because of the installation of wind and batteries near the Alaska coast. If federal funding is required to install the wind turbines and battery placement, federal permits may be required to assure that all the federal requirements have been met. Local and/or state land-use permits may be required for battery placement due to the hazardous waste components involved and the containment issues usually required to avoid spillage. Disposal issues may need to be addressed before construction due to replacement at end of year 10.

The project will need to determine the state and local permits required to site wind, solar and hydro facilities at the village. Alaska's Department of Environmental Conservation, Department of Natural Resources, State Historic Preservation Office, Regulatory Commission and Department of Transportation and Public Facilities need to be contacted to determine what permits are required for the sites to be used for renewable energy. In addition, Federal agencies such as the Bureau of Land Management, Environmental Protection Agency, Federal Aviation Administration, the US Army Corps of Engineers and the Bureau of Indian Affairs may be involved in the permitting process. These agencies will help address the permits required to address land use, land access, noise, navigable air space, subsistence and cultural impacts, biological resource impacts, visual impacts, wetland disturbance, water quality and public health and safety. The lists below are some of the permits that may be required but is not all inclusive.

Federal permits are dependent on whether the project is sited on federal land or contains some kind of federal involvement, i.e., a "federal nexus". The National Environmental Protection Act (NEPA) requires compliance if the project is on federal land or has federal funds involved. Federal Special Use Permits and Rights of Way may be needed if the facility is on federal land or uses federal land to access the project. A permit may be needed for response to the Endangered Species Act. If the project imposes a hazard to air traffic, a hazard determination will need to be undertaken. Impacts to the Clean Water Act will require permits.

State permits will be required if the project impacts fish-bearing waterways, impact cultural, historic or archaeological sites. State permits may also be required if the project crosses state lands.

Local village authorities need to be consulted as well to meet local planning commissions and zoning issues. Local permits may include building codes, setbacks and zoning restrictions.<sup>15</sup>

Typical federal permits include:

- National Environmental Policy Act. The lead agency will depend on land jurisdiction and requires a review of the environmental impacts of proposed actions. The permit is needed if the project is on federal lands; there is a need to access a federally owned transmission line; or there is any funding from federal grants.
- Federal Special Use Permits and Right of Ways. The lead agency will vary depending the land jurisdiction. The permit is required when turbines are placed on federal land.
- Notice of Proposed Construction. The Federal Aviation Administration requires permits when structures are higher than 200 feet (~60 meters). Additionally, the permit is required when tower

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<sup>15</sup> Renewable Energy Alaska Project. March 2011. "Community Wind Toolkit: A guide to Developing Wind Energy Projects in Alaska." Access June 7, 2017 at [http://www.akenergyauthority.org/Content/Programs/AEEE/Wind/PDF/WindToolkit\\_For%20web\\_FINALMarch24\\_2011.pdf](http://www.akenergyauthority.org/Content/Programs/AEEE/Wind/PDF/WindToolkit_For%20web_FINALMarch24_2011.pdf)



is within 20,000 feet of a public use airport with a 3,200-foot runway or is within line of sight of an air defense facility.

- Endangered Species Act. The US Fish and Wildlife service regulates activities where construction or turbine operation threatens endangered species.
- Bald and Golden Eagle Protection Act. The US Fish and Wildlife service regulates activities where construction or turbine operation threatens bald or golden eagles. Golden eagle nests may need to be moved.
- Migratory Bird Treaty. The US Fish and Wildlife service regulates activities where construction or turbine operation threatens migratory birds.
- National Historic Preservation Act. National Historic Preservation Act. The Advisory Council on History Preservation and the Tribal Historic Preservation have jurisdiction to review any impacts to historic and Tribal resources. Action required if the activity impacts tribal resources or the site contains property eligible or listed on the National Register of Historic Places
- Clean Water Act. The Environmental Protection Agency regulates impacts on waters of the United States when there is a potential for discharge due to construction of wind facilities. The US Army Corps of Engineer may be included if construction activity includes dredging or fill material into waterways or wetlands.

Typical state permits include:

- Fish and Essential Fish Habitat. Alaska Department of Fish and Game provides for mitigation measures if a wind turbine site impacts fish habitat. The permit is required if construction requires crossing a fish-bearing water.
- Cultural, Historic and Archeological Resource Consultation/Studies/Permits. The State Historic Preservation Office requires permits when a site is identified that could impact or alter cultural resources.
- Alaska Coastal Management Program. The Alaska Department of Natural Resources regulates sites that are within the Coastal Zone area which includes land up to 200 miles from the coast.
- Land Use, Easements and Right of Ways. The Alaska Department of Transportation regulates projects that have transmission or property on or along property managed by the department.
- Hazardous Materials Permit. Department of Transportation requires permits for hauling batteries due to their hazardous waste content.

## 7.0 Risks

There are a number of risks faced by Naterkag Light Plant, Chefnak utility. The risks include repayment, fuel price, human capital and operational, costs, regulatory, technical, contracting, interest rates and Federal incentives. Each of these risks may have more than one root cause. In addition, other considerations such as sinking funds, project size and collateral issues should be considered. The risks stated here need to be evaluated and included in the analysis when a complete risk analysis of the project is undertaken.

### 7.1 Financial risks

Repayment risk. The primary risk associated with adding renewable energy to Chefnak is repayment risk. The leading cause of the repayment failure is lower than expected renewable generation. Wind generation may not follow historical patterns and less electricity could be generated. In addition, the harsher climate in Alaska may cause more downtime than occurs in milder climates. Both of these issues lead to more diesel generation and higher electricity costs. As a result, consumers face increased electricity rates over those anticipated. The higher rates, in turn, may lead to more payment delinquency. Increasing costs could exacerbate the repayment risk. Due to the potential for higher than expected bills, financiers may evaluate this risk and ask for a working capital fund to make payments in case of a revenue shortfall. Even though working capital earns interest, it still increases the cost of the project as it is either funded from equity (which is higher cost) or from the operating loan, both of which have higher costs than the potential interest earned.

Chefnak may be able to reduce this risk by installing less wind turbines and have less up-front capital to pay. The reduced size of the wind facilities reduces the amount of the electric thermal stoves below the previously specified 650 kW. However the net present cost of the alternatives differed very little (\$16 thousand) with fewer wind turbines.

Fuel prices. If fuel prices are lower than expected, less savings would occur and renewable energy could be more costly than diesel fuel-driven electricity from a full cost perspective. Higher future oil prices would provide even more savings and make the ESCO option profitable. However, if the project is already in place, lower than expected fuel prices would decrease the cost of electricity, because once the equipment is installed most of the costs are fixed and only a relatively small O&M cost is required. Renewable energy will likely still be less expensive from a variable cost perspective.

Human capital risk. Human capital risk is higher in remote villages where the access to labor with the correct skills to operate and maintain a mini-grid may be more limited than in larger urban areas. The opportunity cost to individuals with the skills required to manage, operate and maintain a mini-grid may be higher than remote villages can afford. The individuals need product knowledge of the mini-grid equipment as well as an understanding of the proposed renewable energy systems. They will need knowledge and understanding of the electrical systems including batteries and the capability to manage a more complex distribution system and managing administrative and business management issues. The village may need to use a cooperative or ESCO approach if they don't believe they have the expertise to operate the wind facility. An ESCO may be an alternative, as well, if a cooperative won't undertake the project. However, the ESCO costs are estimated to be greater than the fuel costs of the current facility which would mean that electricity costs could rise to ensure that the ESCO's required rate of return or hurdle rate is met.

Cost Risk. Cost risks have the potential to reduce operating income. Unexpected increases in the costs of labor, materials and supplies in conjunction with projects that have a limited ability to raise prices and thus revenue, can adversely affect operating income. For an ESCO, changing tax rates can also provide a source of cost risk to the project, although it is only lowering the after-tax return rate. The project should remain financially feasible.

Regulatory risk. Financiers will want to see regulatory risk well-defined and the process well-established for obtaining all permits required to begin construction. Without a well-established permitting process and with the time to completion of permitting unknown, financing will need to be from alternative sources such as grants and/or village equity. They will also evaluate the impact of potential changes in regulations and whether they could adversely impact permitting time and designs and in turn the construction costs. Thus, having the project well defined and the permitting, design and construction period confined to a defined period will reduce regulatory risk. Drawn out processes increase the potential for regulatory change, which increases costs.

Technical risk. Financiers are also going to look at technical risk as it impacts the revenues and costs. Construction schedule slippage increases the costs of construction through both direct, overhead and interest costs. Added costs lead to a higher total loan costs during operations. In addition, poor quality construction cost estimates may lead to much higher construction costs. Financiers also review the maturity of the technology being implemented to assure that equipment operates as designed. Failures that reduce capacity factors impact revenue. In the case of the systems designed for Chefnak, the systems are assumed mature although the wind systems analyzed has only been demonstrated. The risk is whether the technology will operate as expected in Alaska winters. Financiers will also evaluate whether any fixes they believe are necessary to make the system work as expected in Alaska's harsh winters may make the project financially infeasible. They will also investigate whether the operating parameters associated with O&M are well understood and the range of potential costs do not impact project debt coverage ratios.

Engineering, Procurement and Construction (EPC) risk. Financiers will also look at the EPC contracts to make sure that contracting risk is acceptable. They will look to see whether the dispute resolution process is defined and provides for cost-effective changes. The financiers will also evaluate default consequences for both community and the contractor and assure themselves the financial institution is not at risk. They will also assure themselves that if the project terminates that their losses are acceptable and minimized.

Interest rate risk. The project could face interest rate risk in the short and long term should the project be attractive to financiers. Construction interest rates may change during the design and permitting period. That could make the project less attractive. In addition, as the project goes forward, interest rates could rise during the construction period making the interest rates for the operating period less attractive. Lastly, as the project moves forward, the riskiness of the project could increase, swelling the spread between the index and the debt rate.

Federal and state incentives risks. Renewable incentives associated with most types of renewables have already expired. The renewable energy federal production tax credit (PTC) provides a tax credit (adjusted for inflation) per kWh of electricity produced. The wind PTC expires at the end of 2019. In 2017, the credit is \$0.0184/kWh. The credit declines 40% in 2018, and 60% in 2019 from the 2016 base of \$0.023. The PTC for all other technologies expired in 2016.<sup>1</sup> A 30% federal ITC is available for solar PV and thermal projects through 2019, after which there is a phased reduction in value of the credit until 2022

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<sup>1</sup> DSIRE – Database of State Incentives for Renewables & Efficiency. 2016. “Renewable Electricity Production Tax Credit (PTC).” Accessed January 2017 at <http://programs.dsireusa.org/system/program/detail/734> (last updated May 24, 2016).

when the credit becomes 10% permanently.<sup>1</sup> The ITC is 26% in 2020 and 22% in 2021 (26 USC § 48(a)(6)). In addition, state incentives are not always completely funded. There is some risk the Alaska Energy Authorities Power Cost Equalization program may reduce incentives or that the Alaska legislature will not fully fund all of the incentive programs.

## **7.2 Other issues associated with financing**

Sinking funds. Once financing alternatives are investigated, the village may need to get grants to provide the upfront equity which will allow the financiers to see a minimum debt coverage ratio of 1.25. If there appears to be inadequate coverage for unusual events, the financier will probably require sinking funds to be set up to prepare for those shortfalls. The sinking funds may be associated with the capacity factor risk and other revenue shortfall risks such as rising fuel prices, capital replacement and major O&M repairs. Revenue risk may arise due wind speed variability, insolation variability, system downtime, equipment failure, and the time require to repair equipment in remote locations.

Project size. Another issue that may detract from ESCO participation is the project size. The project is somewhat small with the proposed mini-grid providing less than 800 kW of renewables which is only being repaired. Additionally, total investment is not significant at \$5.8 million. The project may not provide adequate cash flow to provide an appetite for investment by an ESCO. In addition, ESCOs usually like to see short payback periods. If the project can payback in 7 years or less, investors are more inclined to participate. The project at a 10% rate of return pays back in 7-8 years.

Collateral issues. There may also be issues with what is considered acceptable collateral from the community. Renewable energy projects have little value if they are in remote areas and the power can't be exported and sold elsewhere. Additionally, the financier will want to see that the mortgagee has acceptable bookkeeping and billing systems to assure that repayment is made. In addition, communities may be forced to look for lenders of last resort because the remoteness and the amount of investment required may be too small to attract major lenders.

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<sup>1</sup> DSIRE – Database of State Incentives for Renewables & Efficiency. 2015. “Business Energy Investment Tax Credit (ITC).” Accessed February 15, 2017 at <http://programs.dsireusa.org/system/program/detail/658> (last update December 21, 2015).



## 8.0 Financial Analysis of Selected Option

The project costs \$5.8 million installed. The project *pro forma* assumes a weighted average cost of capital approach to the cost financing as the financing approach at this time is unknown. Chefnak's Naterkaq Light Plant Company as a municipal utility would likely require a nominal 4% rate of return as the cost of their capital if borrowed could be as high as 3% and inflation is assumed to add another 1% to the required rate of return.

An energy service company (ESCO) could provide an alternative approach that provides delivery of electricity services for a rate of return above that which the Naterkaq Light Plant might require. As such the cost of electricity may rise but the renewable energy resources may be more likely to remain viable. The ESCO would require a cost of capital in the 6.8%-10% range after tax at least. We evaluated the ESCO at a 10% internal rate of return. The ESCO would have to pay Federal, state and/or local taxes depending on their location. (There could be tax implications based on the ownership of projects on tribal lands and should be investigated.) Complete equity financing is expensive so debt would probably be included. Thus, between a not-for-profit and an ESCO we have bracketed the relative electricity costs.

Bank financing is usually short term and based on points above the London Interbank Offered Rate (LIBOR). The 12-month LIBOR rate ranged between 2.7 and 3.0 over the last six months.<sup>18</sup> In addition, renewables projects have been financed with tax equity. Typical renewable energy developers don't have an appetite to reduce taxes so they partner with companies that do pay taxes and wish to reduce them. The tax equity usually requires 7.5-9.5% return on equity after taxes.<sup>19</sup> They usually require \$75-\$100 million in projects, so the ESCO would need more projects than an Alaska village to reach the tax equity appetite. The ESCO could also finance the projects based on its balance sheet which obtains debt secured by its assets. Corporate bond rates ranged as follows over the last five months: 10 year BBB+ bonds 3.79 to 4.02% and AAA 2.77 - 3.04%. Thirty year BBB+ bonds yielded between 4.9 and 5.24% over the last five months.<sup>20</sup> Thirty year US treasury rates are around 2.7-3.0% during May – October 2017. Institutional debt would be based on risk of the project above the treasury rate.

Municipal and cooperative entities need to recover the cost of debt, which could be the municipal bond market, bank for cooperatives, grants, or bank loans. The municipal market is based on the credit worthiness of the institution borrowing money. Currently 30-year, AA municipal debt is near 3.88% while B- is near 5.03%.<sup>21</sup> Twenty-year debt is about 0.15% lower.

Small villages are unlikely to have a bond rating to provide a basis for repayment risk. They may be able to receive grants and government subsidized loans to add to their infrastructure to reduce diesel oil consumption. The following provides a short discussion of alternatives: Power Project Loan Fund, Renewable Energy Grant Program, Clean Renewable Energy Bonds (CREBS), and USDA – Rural Energy for America Program (REAP) Grants.

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<sup>18</sup> Global-rates.com. "12 month US Dollar LIBOR interest rate." Accessed October 4, 2017 at <http://www.global-rates.com/interest-rates/libor/american-dollar/usd-libor-interest-rate-12-months.aspx>

<sup>19</sup> Woodlawn Associates. 2017. "Tax Equity 101: Structures." Accessed May 30, 2017 at <https://woodlawnassociates.com/tax-equity-101/>

<sup>20</sup> New York Times. May 30, 2017. "Business Day Markets". Accessed May 30, 2017 at <http://markets.nytimes.com/research/markets/bonds/bonds.asp>

<sup>21</sup> fms bonds, Inc. 2017. "Municipal Bond Offerings." Accessed May 30, 2017 at <https://trading2.fast-trade.com/fmsbonds/bondsearch.do?pager.offset=70>

Power Project Loan Fund. The Alaska Industrial Development and Export Authority provides loans for renewable energy projects to local government, and municipal and cooperative utilities up to \$5 million. Projects over \$5 million require legislative approval. The interest rate varies but the highest rate is tied to municipal bond rates and maturity is set to useful project life. The power project loan fund can be a lender of last resort.<sup>22</sup>

Renewable Energy Grant Program. Upon state appropriation, renewable energy projects can receive grants to cover their costs. The legislature didn't appropriate funds for projects in 2016, so projects are being held over for funding on the next round. Projects are funded directly by the legislature depending on public benefit. The funding can be obtained by investor-owned, municipal, or cooperative utilities, state or local government, utilities, tribal government, and retail suppliers.<sup>23</sup>

Clean Renewable Energy Bonds (CREBS). CREBS can be issued by Tribal, local and state governments, and cooperatives to fund renewable energy projects. The bondholder receives federal tax credits to cover the interest cost while the issuer must pay the principal portion, thus an interest free loan from the issuer's perspective.<sup>24</sup>

USDA – Rural Energy for America Program (REAP) Grants. REAP grants are provided for installing renewable energy systems. The grants and loans are provided to commercial and agricultural producers and to entities that USDA chooses to fund. Grants can be up to 25% of project cost including design, permitting and construction. The remaining funds are provided in the form of a loan. Loan guarantees can't exceed \$25 million.<sup>25</sup>

Some combination of the above funding sources might be used to meet the project funding requirements. In addition, the project may benefit from tax incentives if the utility pays federal, state or local taxes. Alaska provides for property tax exemptions for renewable energy systems. The federal government provides an investment tax credit (ITC) for solar which remains at 30% through 2019 and then declines to 10% by 2022. Geothermal receives a 10% ITC. Large wind receives an 18% ITC in 2018 and 12% in 2019 and none thereafter. Small wind receives no credit. Large wind is greater than 100 kW.<sup>26</sup> Large wind can receive a \$0.0184/kWh production tax credit in 2017. The credit is reduced by 40% in 2018 and 60% in 2019 from the 2016 level of \$0.023/kWh and discontinued thereafter.<sup>27</sup> The federal tax credits, however can only be used by entities that pay federal taxes.

The sources and uses of funds sheet shows that \$5.8 million of funding is required from a mix of sources listed above. The marginal cost of electricity is \$0.407/kWh for diesel generation only with fuel providing \$0.325/kWh of the total. A price of \$0.525/kWh will be required for an ESCO to breakeven to reach a 10% return after taxes without the production tax credit and \$0.518/kWh with the tax credit assuming construction begins by December 31, 2019. Prices for electricity would need to be approximately \$0.10/kWh to recover the extra cost of the electric thermal stoves and the additional wind capacity to

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<sup>22</sup> DSIRE. 2015. "Power Project Loan Fund." Accessed May 30, 2017 at <http://programs.dsireusa.org/system/program/detail/115>

<sup>23</sup> DSIRE. 2016. "Renewable Energy Grant Program." Accessed May 30, 2017 at <http://programs.dsireusa.org/system/program/detail/3080>

<sup>24</sup> DSIRE. 2015. "Clean Renewable Energy Bonds (CREBs)." Accessed May 30, 2017 at <http://programs.dsireusa.org/system/program/detail/2510>

<sup>25</sup> DSIRE. 2016. "USDA – Rural Energy for America Program (REAP) Grants." Accessed May 30, 2017 at <http://programs.dsireusa.org/system/program/detail/917>

<sup>26</sup> DSIRE. 2017. "Business Energy Tax Credit." Accessed May 30, 2017 at <http://programs.dsireusa.org/system/program/detail/658>

<sup>27</sup> DSIRE 2016. "Renewable Electricity Production Tax Credit (PTC)." Accessed May 30, 2017 at <http://programs.dsireusa.org/system/program/detail/734>

operate the stoves if all consumers unexpectedly chose to opt-out of using the stoves. They make economic sense so consumers probably will accept them. In the ESCO/Cooperative approach, the ESCO was assumed to acquire the diesels free of charge. The cost of electricity would further rise to \$0.581/kWh if the ESCO was required to buy the diesel plant, but was still able lease the stoves.

The Naterkaq Light Plant would need to repay the funding over the 20-year project life. Debt coverage ratios should never be lower than 1.25, a lender minimum. The utility would need to charge customers an average rate of \$0.31/kWh the electricity alone, should they decide to operate the facility. The prices would need to be \$0.413/kWh if no one chose to use the electric thermal stoves. The remaining differences between projected prices and the prices listed here are distribution costs and overhead or General and Administrative (G&A) costs (see Table 8-1).

**Table 8-1: Marginal price of village utility and ESCO options**

Alternatives	Chefornak Utility	ESCO
Direct Electricity Price with Thermal Stoves used	\$0.308/kWh	\$0.518/kWh
Direct Electricity Price with Thermal Stoves not used	\$0.411/kWh	\$0.621/kWh

The two different prices for the utility provide a price range for the utility because of the uncertainty associated with consumer acceptance of electric thermal stoves. The thermal stoves breakeven for the consumer if the costs charged to them by the utility for electricity for the stoves is less than \$0.14/kWh. In this case, consumers could be charged \$0.092/kWh which reflects the reduction in diesel fuel use and the annualized cost per kWh of the electric thermal stoves. The two different prices for each entity provide the range for the cost to the utility of the extra wind capacity should consumers opt 100% to lease stoves and 100% opt not to lease the stoves. The thermal stoves electricity cost less than the consumers use of heating oil, thus the use of the thermal stoves is cost effective. However, to the extent that customers are unwilling to use the thermal stoves, the cost of electricity to the village will need to rise to cover the extra renewable energy generation capacity installed only for the use of the thermal stoves. The total electricity consumed by retail consumers is slightly less than the electricity consumed by the stoves, thus the cost differential for domestic consumption is slightly higher than what has to be charged for the electricity for the stoves at \$0.103/kWh.

The primary non-financial benefits to the community would be reduced diesel fuel consumption which would reduce particulate pollution and improve air quality. The particulate matter includes ash, carbon, metallic abrasion particles, sulfates and silicates. The effects of particulate matter exposure include dizziness, headache, and irritation of the eye, nose and throat. Long-term exposure increases the risk of cardiovascular, cardiopulmonary, lung cancer, and respiratory problem.<sup>28</sup> An additional benefit is that it reduces the risk of rising electricity prices as diesel fuel prices rise because the village is no longer so directly dependent on diesel fuel for electricity and home heating.

The Sources and Uses of Funds (Table 8-2) evaluates the installed cost of capital and the costs of alternative sources of funding. The statement of earnings in Table 8-3 for Naterkaq Light Plant indicates that operating earnings provide adequate earnings at a 4% weighted average cost of capital to recover the facility costs over time. The cash flow statement (Table 8-4) provides the basis for the internal rate of return calculation.

<sup>28</sup> OSHA – Occupational Safety and Health Administration. 2013. Diesel Exhaust/Diesel Particulate Matter. Accessed October 4, 2017 at <https://www.osha.gov/Publications/OSHA-3590.pdf>





**Table 8-2: Sources and uses of funds**

USES OF FUNDS, in Millions of Mixed Year Dollars		Go To Main Menu	DEVELOPER'S SOURCES OF FUNDS		Table 5 of 24
Case Study:					
Chefnak					
Microgrid Retrofit			*** Debt	0.0%	0.0 @ 3.0% for 20 yrs
Optimal Solution Chefnak with Thermal Stoves (No demand growth)			Equity	100.0%	5.8 @ 4.0% for 20 yrs
Chefnak Non-profit			Disallowed Equity Broker		0.0
Total Plant Cost (Overnight) w/ real esc 0.0%.					
Sales Tax	0.0%	0.000000			5.8
PV	0.0%	0.000000	*** 1: level, mortgage-style debt payments		
Wind	86.5%	5.030000	WEIGHTED COST OF CAPITAL COMPARISON^^		
Diesel 100 kW	0.0%	0.000000	=====		
Diesel 371 kW	0.0%	0.000000	Before Tax	Constant \$	Nominal \$
Li Ion 1 kWh Battery	4.1%	0.238000	Developer	4.00%	4.00%
System Converter	3.7%	0.214000	Utility	2.23%	3.25%
Electric Stoves	5.8%	0.335000	After Tax		
Home Office OH	0.0%	0.00	Developer	2.97%	4.00%
Misc. Depreciable Cost (last year of construction)		0.00	Utility	2.23%	3.25%
Sales Tax on Misc. Depr. Cost (CTRL-M, Option 3)		0.00	^^A true comparison is not possible		
Of which, P&E - Renewable System	5.0300 *	depr	since the utility equity return is not		
(86.5% renewable * 100.0% depreciable)			taxed within the model.		
Plant & Equipment - Other	0.8 **	depr	TAX TREATMENT		
Geoth Depletable Base	0.0	depl	=====		
Geoth First Year Exp.	0.0	exp	Combined Rate	Federal Rate:	0.0% State Rate: 0.0%
AFUDC Debt - Renewable	0.00 *	depr	Sum of Renewable		5.0 *
Debt - Other	0.00 **	depr	Depreciable Items		
Debt - Deplet'bl	0.00	depl	Tax Credits ITC	0.0%	0.0
Debt - Exp	0.00	exp	ETC	0.0%	0.0
Equity	0.00	20-yr	state	0.0%	0.0 * (1 - 0.0%)
	-----		combined		0.0
	0.00		* Fedl Renew Deprec Base 5.0 @ 5yrs w/50%tax cred. reduction		
Debt Closing	30.0%	0.0 } amort	State Renew Deprec Base 5.0 @ 20yrs w/100%tax cred. reduction		
Debt Underwriter/Broker	40.0%	0.0 } life of	** Fedl Other Deprec Base 0.8 @ 15 yrs		
Debt Printing, Other	30.0%	0.0 } debt	** State Other Deprec Base 0.8 @ 50 yrs		
Equity Organist'l Fee	30.0%	0.0 amort 5 yr	Depletable Basis 0.0		
Equity Tax Advice	30.0%	0.0 exp	Geothermal Expensed 0.0		
Equity Underwriter/Broker	40.0%	0.0 no write-off	Amortized - debt life 0.0 @ 20 yrs		
Startup/Inventory		0.0 non	Amortized - 5 years (Sec 709, 248) 0.0		
Land (for power plant)		0.0 non	Expensed 0.0		
Debt Service Reserve (for Priv. ROR mode only)		0.0	No write-off (Sec 709) 0.0		
Other Reserve		0.0	20-yr equity AFUDC normalization 0.0		
	-----		Land/Startup 0.0		
CHECK: Total Items (before credits)		5.82 vs. Yr. 1 Rate Bas:	5.82		-----
		===== + non-deduct eq exp	-----		5.8

Table 8-3: Income statement of project

EARNINGS STATEMENT		Go To Main Menu	**ROR MODE**		Chefnarak	AK	Microgrid Retrofit					
**Tax Book Accounting**												
		0	1	2	3	4	5	6	7	8	9	10
	Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	Byproduct Credit		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Reserve Interest Earned		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Electricity Revenues		0.71	0.72	0.72	0.73	0.74	0.75	0.75	0.76	0.77	0.78
	Thermal Revenues		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Municipal REPI		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
A{	Total Revenues	0.00	0.7091	0.7162	0.7234	0.7306	0.7379	0.7453	0.7527	0.7603	0.7679	0.7756
	Feed One		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
	Feed Two		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
	Variable O&M		0.15661	0.15817	0.15975	0.16135	0.16297	0.16460	0.16624	0.16790	0.16958	0.17128
	Fixed O&M		0.12196	0.12318	0.12441	0.12565	0.12691	0.12818	0.12946	0.13075	0.13206	0.13338
	Land Rental		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
B{	Major Maintenance Expense		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
	Genl & Admin Exp		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
	Royalty Fee (on electric rev, NOT sum)		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
	Property Tax		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
	Insurance		0.02938	0.02967	0.02997	0.03027	0.03057	0.03087	0.03118	0.03149	0.03181	0.03213
	Gross Receipts Tax (on electric rev)		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
	Total Operating Expenses		0.30794	0.31102	0.31413	0.31727	0.32044	0.32365	0.32688	0.33015	0.33346	0.33679
C{	Operating Income (A-B) B=Expenses		0.4012	0.4052	0.4092	0.4133	0.4175	0.4216	0.4259	0.4301	0.4344	0.4388
	Interest Exp		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Tax Depreciation		1.83	1.38	0.85	0.61	0.61	0.12	0.05	0.05	0.05	0.05
	Repair Depreciation		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
D{	IDC & Depletion		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Amortization		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	State Income Tax (0 unless \$BT\$36=1)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	REPD Tax Deduction		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total Interest, Depreciation, Depletion		1.83	1.38	0.85	0.61	0.61	0.12	0.05	0.05	0.05	0.05
E{	Taxable Income (C-D) D=Fed Tax Deduct.		(1.43)	(1.0)	(0.4)	(0.20)	(0.19)	0.31	0.38	0.38	0.39	0.39
	(Taxes Paid) Benefit	0.0 %Tax rate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Tax Credits		0.0000									
	REPC Tax Credit		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
F{	Total Federal Income Taxes		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total Federal Taxes		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Book Profit After Tax (E-F)		(1.43)	(0.97)	(0.44)	(0.20)	(0.19)	0.31	0.38	0.38	0.39	0.39

Table 8-3: Income statement of project (cont'd)

EARNINGS STATEMENT		Go To Main Menu Optimal Solution Chefnorak with Thermal StoveChefnorak Non-profitTable 7 of 24									
**Tax Book Accounting**		11	12	13	14	15	16	17	18	19	20
Year		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Byproduct Credit		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Reserve Interest Earned		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Revenues		0.78	0.79	0.80	0.81	0.82	0.82	0.83	0.84	0.85	0.86
Thermal Revenues		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal REPI		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
A{	Total Revenues	0.7833	0.7911	0.7991	0.8070	0.8151	0.8233	0.8315	0.8398	0.8482	0.86
	Feed One	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00
	Feed Two	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00
	Variable O&M	0.17299	0.17472	0.17647	0.17823	0.18002	0.18182	0.18363	0.18547	0.18733	0.19
	Fixed O&M	0.13472	0.13606	0.13742	0.13880	0.14019	0.14159	0.14300	0.14443	0.14588	0.15
	Land Rental	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00
B{	Major Maintenance Expense	0.00000	0.00000	0.00000	0.00000	0.25340	0.22549	0.00000	0.00000	0.00000	(0.33)
	Genl & Admin Exp	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00
	Royalty Fee (on electric rev, NOT sum)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00
	Property Tax	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00
	Insurance	0.03245	0.03277	0.03310	0.03343	0.03377	0.03410	0.03445	0.03479	0.03514	0.0355
	Gross Receipts Tax (on electric rev)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00
Total Operating Expenses		0.34016	0.34356	0.34699	0.35046	0.60736	0.58300	0.36108	0.36470	0.36834	0.03805
C{	Operating Income (A-B) B=Expenses	0.4431	0.4476	0.4521	0.4566	0.2077	0.2403	0.4704	0.4751	0.4799	0.82
	Interest Exp	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Tax Depreciation	0.05	0.05	0.05	0.05	0.05	0.01	0.00	0.00	0.00	0.00
	Repair Depreciation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
D{	IDC & Depletion	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Amortization	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	State Income Tax (0 unless \$BT\$36=1)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	REPD Tax Deduction	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Interest, Depreciation, Depletion		0.05	0.05	0.05	0.05	0.05	0.01	0.00	0.00	0.00	0.00
E{	Taxable Income (C-D) D=Fed Tax Deduct.	0.40	0.40	0.41	0.41	0.16	0.23	0.47	0.48	0.48	0.82
(Taxes Paid) Benefit		0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tax Credits		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
REPC Tax Credit		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
F{	Total Federal Income Taxes	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Federal Taxes		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Book Profit After Tax (E-F)		0.40	0.40	0.41	0.41	0.16	0.23	0.47	0.48	0.48	0.82

**Table 8-4: Cash flow statement for project based on 4% rate of internal return**

CASH FLOW		Go To Cases Worksheet	Go To Main Menu	**ROR MODE**	Chefornak	AK	Microgrid Retrofit						
**Accounting of Actual N \$'s Flowing Due to Project**													
			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
G{	Total Revenues (=A on Earnings Stmtnt)			0.709	0.716	0.723	0.731	0.738	0.745	0.753	0.760	0.768	0.776
H{	Expenses (=B on Earnings Statement)			(0.308)	(0.311)	(0.314)	(0.317)	(0.320)	(0.324)	(0.327)	(0.330)	(0.333)	(0.337)
I{	Principal Payment			0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
J{	Interest Expense (from ROW 370)			0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
K{	Def Tax Depst/Wthdrwl(=0 IF \$DEBT_TYPE =1)			0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Sinking Fund			0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
L{	Major Maint Deposit			0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
-----													
M{	Pre-Tax Cash Flow (G+H+I+J+K)			0.401	0.405	0.409	0.413	0.417	0.422	0.426	0.430	0.434	0.439
N{	State Taxes Paid (from ROW375)			0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
O{	Fed Taxes Paid (=F on Earnings Stmtnt)			0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Sinking Fund Payoff													
	After-Tax Cash Flow (M+N+O)			0.401	0.405	0.409	0.413	0.417	0.422	0.426	0.430	0.434	0.439
	Equity Investment excluding eq underwriter		(5.82)										
			(5.82)	0.40	0.41	0.41	0.41	0.42	0.42	0.43	0.43	0.43	0.44
	Minimum Cash Flow	0.0											
	NPV=	0.0	IRR=	4.00%	Solved!	Including equity underwriter, IRR is				4.00%	Current \$ after ta		
=====													
Initial IRR Guess=		4.0	(%)										

**Table 8-4:** Cash flow statement for project based on 4% rate of internal return (cont'd)

CASH FLOW			Go To Cases Worksheet		Go To Main Menu		Solution Chefnak with Thermal StoveChefnak Non-profit						Table 8 of 24
	**Accounting of Actual N \$'s Flowing Due to Project**		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	
G{	Total Revenues (=A on Earnings Stmt)		0.783	0.791	0.799	0.807	0.815	0.823	0.831	0.840	0.848	0.857	
H{	Expenses (=B on Earnings Statement)		(0.340)	(0.344)	(0.347)	(0.350)	(0.607)	(0.583)	(0.361)	(0.365)	(0.368)	(0.038)	
I{	Principal Payment		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
J{	Interest Expense (from ROW 370)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
K{	Def Tax Depst/Wthdrwl(=0 IF \$DEBT_TYPE Sinking Fund		0.000 0.000	0.000 0.000	0.000 0.000	0.000 0.000	0.000 0.000	0.000 0.000	0.000 0.000	0.000 0.000	0.000 0.000	0.000 0.000	
L{	Major Maint Deposit		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
M{	Pre-Tax Cash Flow (G+H+I+J+K)		0.443	0.448	0.452	0.457	0.208	0.240	0.470	0.475	0.480	0.819	
N{	State Taxes Paid (from ROW375)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
O{	Fed Taxes Paid (=F on Earnings Stmt)		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
	Sinking Fund Payoff												
	After-Tax Cash Flow (M+N+O)		0.443	0.448	0.452	0.457	0.208	0.240	0.470	0.475	0.480	0.819	
	Equity Investment excluding eq underwriter												
			0.44	0.45	0.45	0.46	0.21	0.24	0.47	0.48	0.48	0.82	
	Minimum Cash Flow		0.0										
	NPV=		0.0	5.82	\$mil		After tax discount rate			4.00%			
Initial IRR Guess=			4.0										



## **Appendix A**

### **Future Business Case Requirements Outline**

*The appendix includes an outline of the information that will be required to evaluate a detailed business case for actual financing. The most relevant information will include more in-depth estimates of the costs based on the technical analysis of the project reported in the Chefnak Mini-grid Configuration Options<sup>1</sup>. In addition, a more detailed description of the financial analysis will need to be undertaken as more detail gets put together before financing, but after the technical and permitting details are worked out. A more extensive exposition of the risks is involved. The following provides a detailed list of the items that may be required.*

#### **Technical**

There are several approaches to providing the detail to the business case above. Best practice would be to provide the complete set of alternatives in detail and describe the approach to determining the optimal combination of components. In addition, a detailed description of the components and how the costs were developed for each is delineated. In this case we refer you to the technical analysis of the Chefnak project.

- Methodological Approach
- Alternative 1
  - Mini-grid components
  - Schedule with enough detail to describe alternative
  - Costs
  - Benefits
  - Sensitivity analysis
- .....
- Alternative X
- Technical Details of Mini-grid
- Technical Details of Wind installation
  - Technologies analyzed and rationale for selected technology
    - Turbine size,
  - Wind speeds
    - Capacity factors
    - Variability
  - Construction schedule
  - Permitting issues
  - Impact of location on costs
  - Impact of extreme cold on costs

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<sup>1</sup> Jimenez, T, et al. 2017. “Chefnak Minigrid Configuration Options.” National Renewable Energy Laboratory, GMLC-XXXXX



- Etc
- Technical Details of PV installation
  - Technologies analyzed and rationale for selected technology
    - Installation size,
  - Insolation
    - Capacity factors
    - Variability
  - Construction schedule
  - Permitting issues
  - Impact of location on costs
  - Impact of extreme cold on costs
  - Etc
- Technical Details of Battery installation
  - Technologies analyzed and rationale for selected technology
    - Installation size, kW and kWh
  - Round trip efficiency
  - Impact of location on costs
  - Impact of extreme cold on costs
  - Etc
- Integration components and details
  - Technologies analyzed and rationale for selected technologies for each component
  - Impact of location on costs
  - Impact of extreme cold on costs
  - Etc

### **Permitting**

The section should include all the permits that need to be obtained and the steps, time and cost required to obtain the permits:

- Building permits
- Environmental permits
- Other

### **Financial**

The financial section should include the detailed information that was used to analyze the financial aspects of each alternative and the types of financing analyzed. The section should include the assumptions used to analyze each of the alternatives and their sources. The approach should be discussed including a discussion of the pro forma used to analyze the alternatives. A spreadsheet model would accompany the written documentation to illustrate the quantitative metrics of each alternative considered. The list includes:

- Installed costs (\$/kW, \$/kWh) of alternatives by component system costs
  - Wind
  - Solar
  - Battery
  - Balance of System for each alternative
- Length of construction period
- Capacity factors
  - Wind
  - Solar
  - Diesel generator
  - Round trip efficiency for battery

- Operating costs of each alternative
  - Variable Operations & Maintenance (O&M) costs by component
    - Fuel
    - Non-fuel O&M
  - Fixed O&M
  - Escalation rates expected
- Major maintenance costs including expected year of inclusion
- Depreciation schedules
  - For each component
- Tax rates
  - Income tax rates
    - Federal, State, Local
  - Gross receipts tax?
  - Sales tax rates
  - Property tax rates
- Insurance rates (make sure not to double count if included in the O&M costs)
- Incentives
  - Federal, State, Local
    - Investment tax credits, production tax credits
      - Rates by year of construction beginning
- Prices
  - Diesel prices, expected, potential variance
  - Any other value discovered during analysis
  - Escalation rates for each
- Expected hurdle rates required by alternative
  - ESCO rate
  - Village utility rate
  - Other alternative
- Financing Assumptions
  - Alternatives Studied
    - Debt financing fees
    - Interest rates during construction
    - Interest rates during project life
    - Debt/Equity percentages
    - Type of financing
      - Bank, bonds, grants,
        - Repayment function – mortgage style, other
    - Length of financing

## Risks

The major risks should be summarized. Risks that apply to all cases can be summarized separately. The section should summarize the risk and the mitigation approach that has been developed. Private finance organizations will develop a list of risks and indicate who owns them if private finance is involved. Below is an extensive but not all-inclusive lists of risks. The results of the risk analysis should be summarized in this section and the complete analysis placed in an appendix.

- Financing Risk
  - Project feasibility risk
    - Adequate internal rate of return to entice investors
    - Debt service coverage ratios adequate for financing
    - Adequate collateral for cash flow shortfalls

- Payback risk
    - Institutional capacity risk or ability to repay debt
      - Community's ability to raise prices
        - to meet fuel price changes
        - to meet declines in demand
          - Historic load profiles are needed
      - Lack of timely utility customer payments
    - Project scale sufficient to meet payback requirements
      - Long payback periods may not be acceptable especially for bank financing
  - Acceptable collateral needs to be identified for community loans
    - Note: (Community utility assets may have little value in an isolated community with few alternative uses.)
  - Acceptable bookkeeping and records need to be made available to provide background on ability to repay
  - Availability of financing
    - Project of adequate size to attract pay for performance contractors
    - Interest rate risk
      - Overall interest rate movements
      - Spread between selected index and the debt rate
      - Variability enough to make project infeasible
    - Cost of debt placement still allows project feasibility
- Community's human capital risk
  - Probability of utility employee turnover can be a barrier
  - Capable of managing complex distribution systems
  - Capable of managing administrative and business management requirements
- Incentive risks
  - Federal incentives declining and eliminated in the near term
  - Alaska Energy Authorities Power Cost Equalization program may reduce incentives
- Revenue risk associated: with
  - wind speed variability
  - insolation variability
  - system downtime
  - equipment failure
    - Time to repair acceptable?
- Technical risk
  - Impact of construction schedule slippage
  - Impact of construction cost overruns
  - Failure of system to work as designed
  - Fixes necessary make project infeasible?
  - Are O&M requirements understood and a maintenance plan in place?
- Cost risk
  - Unexpected cost escalation
    - Labor
    - Materials
    - Supplies
  - Higher operating costs than expected
    - Remote location risk
      - Added costs and range of costs
  - Change in tax rates

- Regulatory risk
  - Permitting risk
    - What permits are required
    - Issues in getting permits
    - Time to completion fixed or open-ended
  - Change in law or regulation risk
- Schedule risk
  - Impact of federal tax incentives to slipping construction start dates
  - Potential cost risk of slipping schedules
- Impact cold weather on operations and costs
- Contracting risk (if third party constructs or constructs and operates)
  - Dispute resolution defined?
  - Community default consequences?
  - Contractor default consequences?
- Termination provisions defined?



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