NOVEMBER 8TH, 2023

FINAL REPORT

POWERING A SAND MINE USING SELF-GENERATION & RENEWABLE ENERGY

Concept and Profile Analysis Document
DRAFT

Proprietary and Confidential

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EXECUTIVE SUMMARY

The Assignment –

The Client, [redacted], is a company with multiple locations in the US where it mines sand for industrial uses. Managment currently faces a decision in the [redacted] mine as to how to provide for the expansion of the plant's throughput through the use of additional electrical devices, notably hydraulic pumps which are used to blast the sand from the hillside. Management predicts that over the next 5 years the electric load from this expansion could nearly double the energy and power usage from current requirements. Conversations with the local electrical utility – [redacted] Electric Cooperative ([redacted]) – have so far pointed to the need to install additional transformation through a substation at the mine in order for the utility to be able to service the upcoming predicted load. Such a substation would cost ----- [redacted] an estimated $1.5M to $2M dollars, and continued purchases of energy and power. The company is therefore looking for alternatives to this situation.

The Potential Solutions –

In this report AED investigates alternatives to the electrical supply from [redacted], notably the use of Solar Photovolaics and possibly wind energy or other sources. The thinking is that instead of adding to the capacity of the site to accept energy from [redacted], there may be opportunities to offset or replace this requirement from other methods. Due to the ample use of natural gas on the site, the concept of self-generation using gas generators was also raised for consideration.

In order to determine any first-order benefits from other sources, a clear understanding of the energy use profile of the operation was needed. Only by understanding how and where the site uses various types of energy and power can alternatives be developed. The load profile of both existing and expansion electric and gas needs forms the first stage of the report.

As the loads were being analyzed it became clear that this mining operation uses a combination of heat energy and electrical energy to run its processes. Electrical energy is used in the form of hydraulic pumps and other devices (conveyors, etc.) in order to extricate the sand, and then this sand is dried for sale using natural gas heaters. The close correlation of these energy uses allowed us to also look at the use of Combined Heat and Power (CHP), or 'co-generation' as it is commonly called.

This report is intended to serve as a top-level 'road map' for the Client, offering data metrics for the options explored. It is left to further work to develop in-depth engineering studies and implemenation of the concepts explored in the report.

This site uses a LOT of electrical and heat energy. The decisions on how to supply that energy represent a number of financial choices to the owners. Each of these choices may be viewed as an investment in the future of the company. The self-generation of energy, whether by solar or other methods, requires a larger investment than a substation. Although the relatively straight-forward addition of a new substation for [redacted] can be seen as an investment in the future (allowing the company to expand), it is more of a one time expense. The other options explored in the report are truely investments, since they produce some sort of savings that offset their Capital Cost over time. Whether owned directly by the company or acquired through some sort of Power Purchase Agreement from a third-party ownership program, each of these techniques is an investment that stands on its own. The report attempts to touch on these issues and show their relative effectiveness to overall energy needs at the site.

Conclusions –

After having gone through the process of producing the report, AED is in a position to offer some conclusions and findings for the benefit of [redacted] management, along with a 'roadmap' of action items that it believes should be implemented in order. Those conclusions are listed below and are backed up by the metrics contained in the full report.

1. *Financially viable alternatives to spending $1.5M+ on a new transformer or substation for the* [redacted] *Electric Coop do exist.* Instead of spending money to allow more power to flow into the site, investments can be made to reduce the need for additional energy by means of either self-generation of renewable solar energy in a 'Microgrid' environment.
2. *Both the solar and self-supply alternatives should be viewed as viable investments* that either save or generate energy (kWhrs) or power (kW) at lower overall prices than received from [redacted]. Although the cost of energy generated from self-supply is slightly higher than the current cost of electricity from the Coop ($.078 vs. $.068/kWhr), the savings in Demand Charges (over $1,050,000/yr) and Value of Waste Heat Recovery ($1,630,000/yr) alone make the co-generation self-supply concept viable.
3. *The co-location of large electrical plus dryer loads is an ideal use case for co-generation via natural gas generation.* Individual 'powerhouses' could be located on the site at large load centers, each operating under a collective 'Microgrid' environment.
4. *The Co-Generation concept can be introduced in various sizes, or stages, over time.* Management could decide to employ self-supply at the largest current use load center at the site (Heating #4 & 5 and Water #2 buildings) and then add additional self-generation later. The Microgrid/generation sources could be a partial or total solution to the Client's 5 year growth plan.
5. *The overall energy policies that the Client decides to employ can be 'staged' or phased.* Each would be a component in an overall 'Microgrid' to be established at the site. Over the next 5 years the need for a new substation would be eliminated. Discussions should be held by management as to the actual required timing of the expansion load requirements. For instance, during next year alone the expansion load appears to be nearly 15,000,000 kWhrs, or a 36% increase over the entire site load in one year. Perhaps this load could be 'phased in' in order to allow other self-generation measures to take effect.
6. *The timing of implementing any self-generation options needs to be discussed in light of the need for the* [redacted] *substation.* Solar projects of this scale will typically require 9-16 months in order to design, permit, interconnect and operate. Almost half of that time is taken by the local utility to allow interconnection, as the utilities are not usually happy to have their energy sales taken away. Of course, if the solar arrays are kept totally behind the meter (no

exported energy) then the interconnection problem goes away. But this would require the arrays to be sized substantially smaller than proposed (+/- 7MW AC) so that excessive solar energy is not 'stranded'.

The creation and implementation of a Microgrid utilizing natural gas generators could also take up to a year or more to permit, build, and (perhaps) interconnect. The Mainspring generators suggested in the report have lead times as long as 10 months for delivery. Although the Mainspring units have been suggested due to efficiencies, additional co-gen units are available from sources such as *CapStone* with shorter deliver schedules.

The timing of the options is important, as it may be found that rescheduling part of next years' projected expansion requirements would allow self-generation the time to 'catch up' with the expansion.

7. *Solar PV can be a profitable investment at the site. Management has proposed 2 locations at the site which could be used to construct a total of 13.3MW of solar power (or more if additional land is available).* Based on the cost of energy at the site (and ignoring any demand savings, which are unpredictable) such an investment would result in a 15% unleveraged Internal Rate of Return. This assumes that net metering is allowed by [redacted] If not, the systems need to be downsized to just 7MW to avoid 'stranding' excessive amounts of energy.
8. *The application of solar PV arrays, while making an attractive investment on their own in the form of energy costs, do NOT replace the need for additional power requirements.* Because the sun is not always available, the solar arrays could not be counted on to provide POWER needed for the facilities 24 x 7. If only the solar options were selected the company would still require the need of the substation from [redacted] to provide peak power.
9. *The specifics of system designs, including sizing and strategies, should only be implemented after discussions are had with* [redacted] *Electric Cooperative* in order to ascertain the existence of or amount of Net Metering capability, they would be willing to provide. In [redacted], Net Metering is an option for a Cooperative. This report did not contact [redacted] so as to not 'tip the hand' of management.
10. *Both solar and self-generation have large tax benefits associated with them*. If the Client is not in a position to utilize these benefits themselves, it is suggested that a form of Independent Power Producer (IPP) relationship be struck with outside investors.
11. Both solar and self-generation would provide meaningful ESG aspects to the Client. The value of these benefits was not quantified in this report.

Suggested Next Steps:

1. Internal Discussions about the report and potential questions for AED.
2. Discussion about options for Net Metering with [redacted] Electrical Coop.

3. Creation of a 'Front End Engineering Design' (FEED) for the project to further detail system designs and electrical engineering. The Microgrid concept would be detailed in this stage as well, and could extend to other 'phases' of energy projects as they are brought on-line.
4. The first and most obvious place to start implementation would be to create co-generation of electric and heat at the Dryer 4&5 / Wet #2 buildings. The electric loads and heat loads are in close proximity to each other in this location and represent a large portion of the site's energy load (30% of current case, 15% of future case). Such a phase could produce over 12,000,000 kWhrs/year and 5% of the site's total heat load. This also creates a project which is relatively compact, and could be implemented quickly.
5. Unless the company wishes to own the solar arrays themselves (and have the tax appetite for the Investment Tax Credits and Depreciation write-offs), we suggest that the company investigate a Power Purchase Agreement option with a solar developer for the solar PV option. The solar arrays would need to be explored with [redacted] if they are to interconnect with the grid.

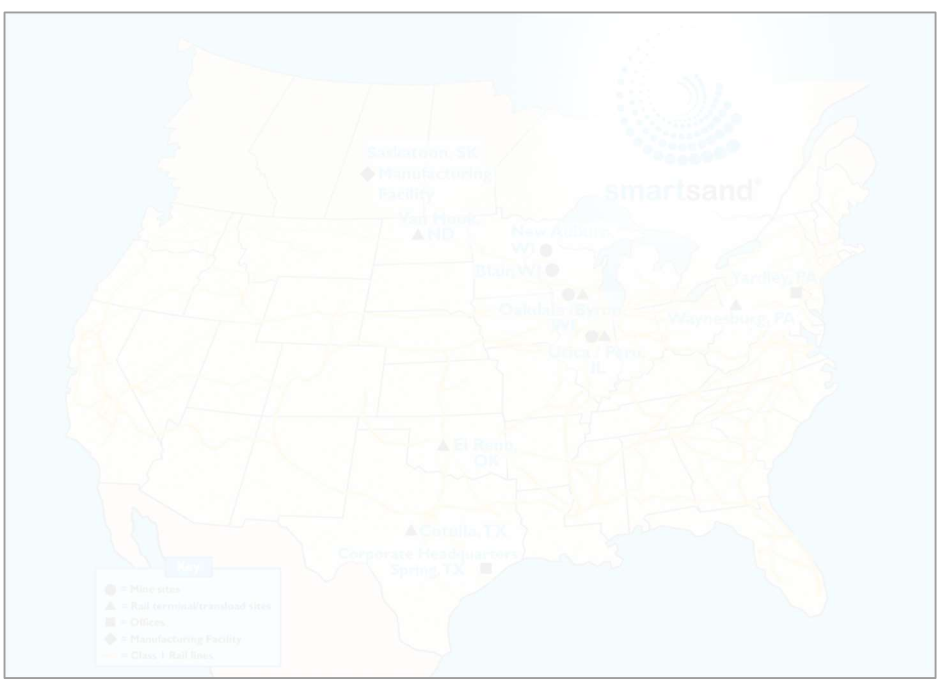
INTRODUCTION

The Assignment –

The Client, [redacted], Inc, is a company with multiple locations in the US where it mines sand for industrial uses. One of its sand mining operations is located [redacted]. This office contacted AED for assistance with its energy loads. The Client is currently in the process of expanding new mining equipment which may not be supportable by the local electric coop unless a new substation/transformer costing an estimated $1.5M+ is installed. The purpose of this report is to provide the Client with an evaluation of alternate investments which could supply or augment the required additional electric needs with self-generated power instead.

The client also wishes to explore the use of solar energy and other green methodologies. Therefore the study will include an investigation of solar PV, energy storage for demand reduction and possible Time-of-Use savings, and co-generation using heat recovery from on-site electrical generators.

For timing reasons the investigation has been broken into 2 phases. The first phase, which is the focus of this report, is to provide a clear understanding of the site's energy needs and build an energy 'profile' of the site in order to suggest optional methodologies which could be employed by the Client, along with 1st estimates of cost and savings. A second phase would be based on feedback from the Client and provide more in-depth designs and specifications which would lead to permitting and development. That effort would result in a 'Front End Engineering Design' (FEED) document for implementation.



THE SITE AND ITS ENERGY

The [redacted] site is an open pit mine located near [redacted]. It is serviced by both highways and a rail line spur which enters the property.

The mine uses hydraulic water pressure from water 'cannons' to mine the sand from hillsides located on the property. The sand is then moved by conveyor belts to drying facilities where natural gas dryers heat the sand to dry it for shipment via rail.

The energy use at the site is primarily that of heating the sand via natural gas burners and running the water pumps, conveyors, and other equipment by means of electricity. The site is serviced by the [redacted] Electric Cooperative ((800)[redacted], www.[redacted].com) through approximately 20 electric meters, not including off-site office locations.

Of interest to the Client at this time is whether or not a new substation should be funded for the Electric Cooperative in order to add electrical capacity to the site. It has been reported that the substation would cost approximately $1.5M, and would need to be put into the company's 2024 operating budget. It is hoped that this report could put alternatives to that substation into perspective.

The Project site in [redacted]. Potential solar PV locations are depicted at the upper right.

The Electric Load

Electric bills from the Cooperative have been collected and are available in the Client's project dropbox. There are 19 on-site electric meters that have been studied. During the period from October 1st, 2022 to September 30th, 2023 the site used a total of 40,309,995 kWhrs of electricity. The table below shows these meters and their corresponding attributes for the latest billing period:

Meter No.	kWhrs/yr	Rank	Acct No.	Desc.	$Pk kWhrs	$OP kWhrs	Dist kW$	Pwr Sup kW$
[redacted]	3,578,383	8.2%	5026	New Wet Plant	0.0638	0.0438	3.25	9.1
[redacted]	3,120,412	7.1%	5025	Pond Pump Service	0.0638	0.0438	3.25	9.1
[redacted]	713,297	1.6%	5054	East Quarry Hydr. Mining				
[redacted]	2,075,475	4.7%	5048	East House 12 for UFR	0.0638	0.0438	3.25	9.1
[redacted]	142,515	0.3%	5050	East House 14	0.0638	0.0438	3.25	9.1
[redacted]	3,168,097	7.2%	5010	Dry Plant 2	0.0638	0.0438	3.25	9.1
[redacted]	2,261,672	5.2%	5005	Pump House	0.0638	0.0438	3.25	9.1
[redacted]	4,464,513	10.2%	5029	Dry Plant 4&5	0.0638	0.0438	3.25	9.1
[redacted]	3,813,934	8.7%	5031	Scrceen house 4&5	0.0638	0.0438	3.25	9.1
[redacted]	4,179,778	9.5%	5004	Dry Plant 1	0.0638	0.0438	3.25	9.1
[redacted]	3,244,848	7.4%	5003	Wet Plant				
[redacted]	2,646,184	6.0%	5019	Phase 2 Mine Pump	0.0638	0.0438	3.25	9.1
[redacted]	3,639,436	8.3%	5028	Dry Plant 4&5	0.0638	0.0438	3.25	9.1
[redacted]	3,147,215	7.2%	5016	Dry Plant 3	0.0638	0.0438	3.25	9.1
[redacted]	342,720	0.8%	5047	Pump PU2301 and E-House 15	0.0638	0.0438	3.25	9.1
[redacted]	692,042	1.6%	5052	Southwest Mobile mine				
[redacted]	1,887,076	4.3%	5044	West Side Mobine Mine	0.0638	0.0438	3.25	9.1
[redacted]	550,660	1.3%	5024	Dry Plant 4&5	0.0638	0.0438	3.25	9.1
[redacted]	220,121	0.5%	5053	E-house 16	0.0638	0.0438	3.25	9.1
	43,888,378							

Table 1 - Load Centers at the Site

Meters with no Peak or Off-Peak values are not on TOU.

Interval data reports in CSV format have also been obtained. This interval data is recorded by the Cooperative which bills under a Time of Use (TOU) rate structure. Approximately 36% of the electrical load is used On-Peak, and 64% is Off-Peak. The table below shows the On-Peak vs. Off-Peak usage for the past 3 years:

	On-Peak	Off-Peak	Total
2020	9,047,405	14,403,845	23,451,250
2021	11,224,182	20,028,510	31,252,692
2022	14,334,351	26,872,828	41,207,179
Totals	34,605,938	61,305,183	
Percent	36.1%	63.9%	

Table 2 - Peak/Off Peak usage

This information is useful as it may indicate opportunities to use electrical energy storage to shift between peak and off-peak rates. In this case however, the local Cooperative only charges a $.02 premium for on-peak power, which will likely not justify the use of expensive batteries.

Power (kW), as opposed to Energy (kWhrs) at the site has now reached 9,087 kVA in October of 2022, and often exceeds 8,000 kVA. This load is planned to increase in the coming years as depicted in one of the following sections of the report.

When viewed in the aggregate we begin to see the profile of electric use at the site. The Chart below shows all of the on-site electric loads in comparison.

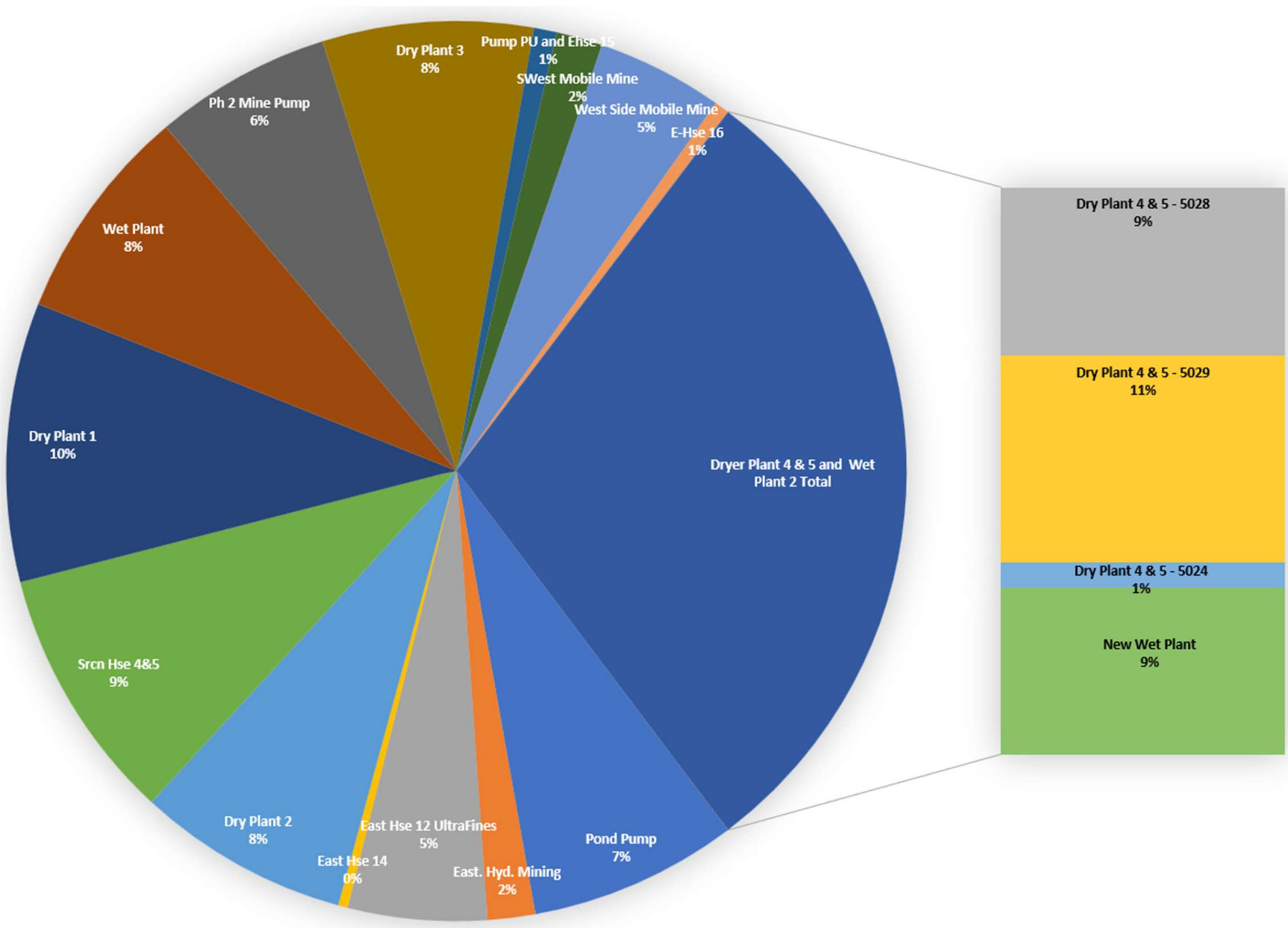


Figure 1 - All electric loads on site - kWhrs/yr (thru 9/30/23)

Note that one grouping – Dryer Plant 4 & 5 and Wet Plant #2 – constitute 30% of the entire site load. This is important, since these buildings are located together and offer opportunities in local self-generation and even co-generation.

The Time of Use data for the site was plotted graphically for every 15 minute period between 10/1/2022 and 9/30/2023 and appears as follows.   Note that other than an occasional total power failure, the site runs continuously.   In recent months several larger dropouts appear, raising the question of whether adequate power is available at the site now, or if the site is experiencing brown or blackouts.

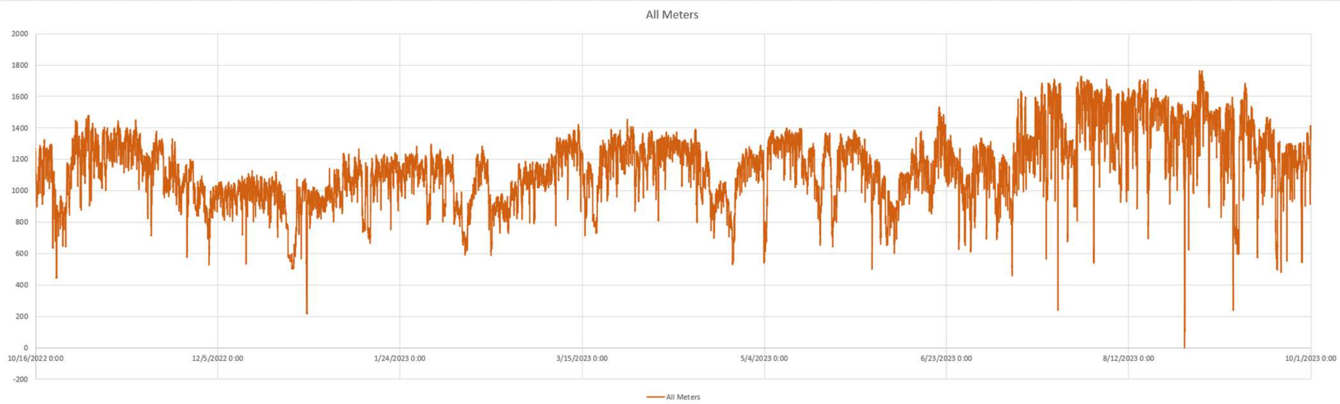


Figure 2 - Annual 15 minute load from all meters.

The figure below shows the on-site location of each of the meters and load centers. Dryers 4 & 5 and Wet Plant #2 are highlighted. The numbers on the figure refer to the *Descriptions* in Table 1.

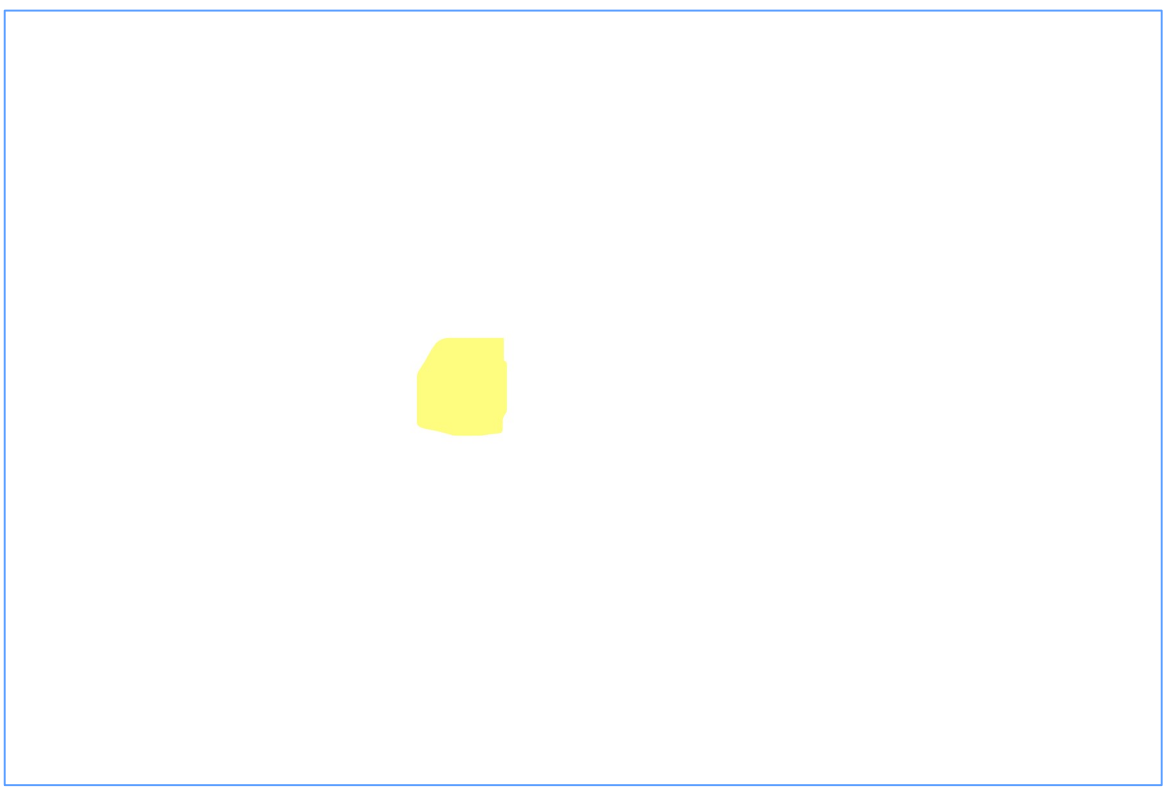


Figure 3 - The electrical loads around the site.

Pricing for the Energy and Power is derived from Electric bills from as later as 10/23. The following table summarizes the site's electrical energy costs. The Blended energy cost is derived from am apportionment of Peak to Off-Peak usage of 34.8% to 65.2%, respectively.

	$/Off-Peak kWhrs	$/On-Peak kWhrs	$/Blended kWhrs	Power (Dmd – $/kW)
2023	.058	.078	.066	$12.60

Table 3 - Pricing of Electrical Energy and Power

Natural Gas Load

Natural Gas is used at the site for the purpose of drying the sand before shipment. A review of the gas usage was conducted.

The following table represents the historic and present usage of Natural Gas at the site (the last 4 months of 2023 are taken as the previous year values):

Gas Usage - Decatherms								
	2016	2017	2018	2019	2020	2021	2022	2023
Jan	11,440	41,525	64,899	32,811	58,380	67,421	65,037	110,856
Feb	15,762	60,056	63,389	54,374	81,979	43,883	63,634	91,146
Mar	15,971	68,133	73,452	76,100	81,712	63,164	89,204	96,150
Apr	16,113	57,806	79,892	75,296	35,645	56,964	102,644	77,236
May	16,207	60,958	81,383	60,892	10,815	46,868	97,041	92,089
Jun	31,898	45,703	70,952	89,990	19,598	30,964	109,316	67,147
Jul	26,210	52,034	85,833	57,485	28,916	36,584	92,306	79,642
Aug	19,622	51,740	73,299	57,375	14,707	56,340	79,317	78,348
Sep	19,668	60,330	69,639	47,660	31,443	56,658	65,501	65501
Oct	24,884	69,077	58,769	46,122	32,793	54,918	77,364	77364
Nov	23,826	65,992	64,249	34,472	38,908	48,276	105,564	105564
Dec	28,787	55,628	59,937	51,366	60,557	74,340	88,925	88925
DTH	250,387	688,981	845,694	683,941	495,453	636,380	1,035,852	1,029,968

Table 4 - Natural Gas Usage at [redacted]

One Decatherm is equal to 1,000,700 BTUs of energy content. Therefore the current heat energy load at the site can be expressed as 1,030,689,000,000 BTUs.

Co-incident usage: Less detailed information is available for the gas usage than the electrical usage, which is typical of gas billing. However, the mining operation is basically a 7 x 24 hour operation, so the natural gas load is considered proportionate with the electric loads used by the dryer rooms.

Co-incident usage of both electricity and heat is an important metric in industrial plant design, as it can lead to instances of energy savings via co-generation, which is explored in a later section.

Future Growth and Expansion Impacts

Electrical Increase:

The Client has provided the following schedule of expansion equipment and expected additional electric loads. The last column, 'Management Projections' indicates the amount of expected kWhrs added to the existing load for that year by management. The increased load is primarily due to the use of additional pumps. The balance of the table converts the HP size of the equipment to kWhrs/year in order to confirm management's projections.

The projected additional energy requirements are confirmed, under the assumption that a 100% Capacity Factor is applied. In other words, these values are valid if the equipment is run on a 24 x 7 schedule every hour of the year. This assumption should be clarified.

If validated, the additional energy and power load would increase according to the following table. Note that the increase of 39,875,520 kWhrs/yr represents nearly a 100% increase over current usage, bringing the total projected electrical energy load in 2028 to 80,185,515 kWhrs/yr.

Year	East - HP	Est - kW	East - kWhrs/yr	West - HP	West - kW	West - kWhrs/yr	Total kWhrs/yr	Mgt Proj.
2024	1100	808	7,078,080	1200	882	7,726,320	14,804,400	14,828,979
2025	300	220	1,927,200	300	220	1,927,200	3,854,400	3,868,429
2026	300	220	1,927,200	1200	882	7,726,320	9,653,520	9,671,073
2027	300	220	1,927,200	600	440	3,854,400	5,781,600	5,802,644
2028	300	220	1,927,200	600	440	3,854,400	5,781,600	5,802,644
Capacity Factor:		100.0%						

Table 5 - Future Power Expansion

Unless the new equipment actually replaces existing equipment, there will also be a corresponding increase in the Power (kW or kVA) aspect of the site's load. Maximum power at the site reached 9,087 kVA in October of 2022. This value is expected to reach 13,700 kW by 2028.

Gas Increase:

According to management the additional electric load will NOT increase the Natural Gas load.

Total Increases:

Table 6 therefore represents the total Electric Load increase through 2028.

Year	kWhrs/yr	% Elect. & NG Inc.
2023	*40,309,995*	
2024	55,114,395	136.7%
2025	58,968,795	107.0%
2026	68,622,315	116.4%
2027	74,403,915	108.4%
2028	80,185,515	107.8%

Table 6 - Electrical Load Increases

For planning purposes in this report, we will focus on the total predicted increases planned through 2028 instead of annual increases. A five-year plan is considered more appropriate when dealing with larger energy investments. Therefore, we will now look at two load profiles: the current profile as shown in previous sections, and a 'future' projection for 2028 which will be roughly twice as large as the current profile.

Because the overall load is projected to increase due to the use of larger pumps, this will have an effect on the breakdown of the load profile with respect to the location of the load centers within the site. Dryers 4 & 5 and Wet Plant 2 are NOT expected to expand in size, and therefore the mix of energy usage will change as shown in the following diagram (Note how Dryers 4 & 5 and Wet Room #2 now only account for 15% of the site load).

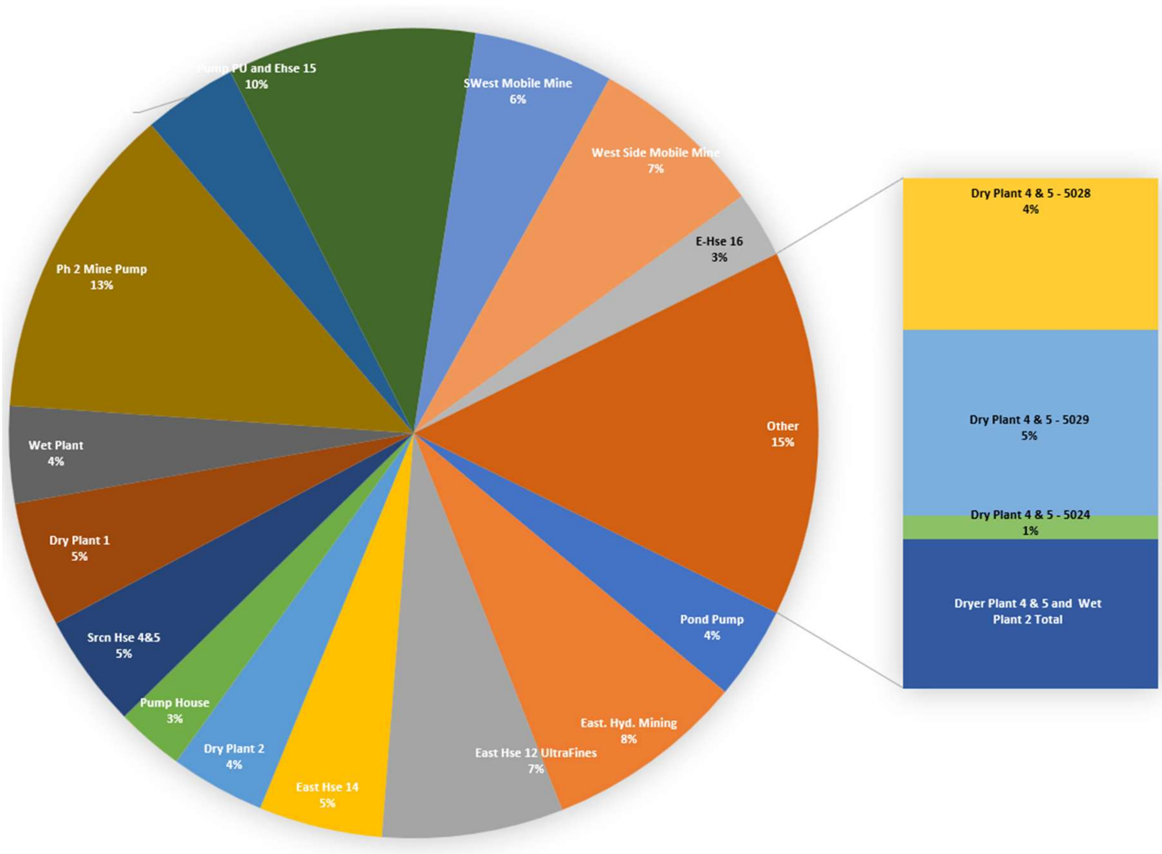


Figure 4 - Future Electric Load - All Meters

Conversion to BTU's – the 'common denominator'.

In order to evaluate the opportunity to use co-generation, we need to express the Electric and Gas energy loads in a common unit of measure. When comparing electrical generation and heat the BTU is typically used. Every electrical generator converts some of the input energy content into electricity and the inefficiency of the genset results in waste heat. This waste heat can often be recovered and used to reduce fuel intake – in this case the natural gas used to dry the sand.

The Excel digital model of the site energy load shows this conversion in 15 minute intervals and uses the Time of Use meter records. The totals are expressed in the table below.

	Gas Input (MBTU)	Electric Out as MBTU	Waste Heat MBTU
Current Loads	305,818	137,618	168,200
2028 Future Loads	635,489	285,970	349,519

Table 7 - Energy Requirements as BTUs

Self-Supply Options – Formation of a 'Microgrid'

A microgrid is a localized and self-contained electrical system. It is designed to provide reliable and efficient energy supply while enhancing the sustainability and cost-effectiveness of the mining operation. In the context of [redacted]'s mining operation it would utilize and control both solar PV arrays and electric power generated from other sources, such as natural gas generators.

The microgrid integrates various sources of energy and enables seamless switching between them to optimize power generation.

1. **Solar PV Arrays:** The solar PV arrays harness energy from the sun during daylight hours. This renewable energy source is clean and abundant, making it an ideal choice for reducing carbon emissions and operating costs at the site. Excess solar power could be stored in batteries or used to supplement other energy sources when available.

2. **Natural Gas Generators:** Natural gas generators serve as a reliable backup and primary power source when solar energy is insufficient, such as during nighttime or cloudy days. They provide a consistent power supply and can be quickly ramped up to meet increased demand, ensuring uninterrupted mining operations.

3. **Energy Storage**: Energy storage solutions like batteries store excess energy generated by the solar PV arrays. These batteries release stored energy during periods of low solar generation or high demand, ensuring grid stability and reducing reliance on natural gas generators. This contributes to cost savings and reduced emissions. Whether electrical storage would be used at this site is covered in a subsequent section.

4. **Advanced Control Systems:** Microgrids use advanced control systems and smart algorithms to manage the flow of electricity, monitor energy generation and consumption, and coordinate the operation of different energy sources. These systems optimize energy use, minimize downtime, and maintain a stable power supply.

5**. Grid Independence:** Microgrids are often designed to operate independently from the main utility grid, providing energy resilience in remote mining locations. They can also be connected to the grid, allowing excess energy to be exported or importing power when needed.

6. **Environmental Benefits:** By incorporating solar PV arrays and natural gas generators, site operations can reduce its environmental footprint. Solar energy decreases greenhouse gas

emissions, while the use of cleaner-burning natural gas minimizes air pollution compared to traditional diesel generators.

In summary, a microgrid for a mining operation that combines solar PV arrays with natural gas generators is a versatile and sustainable energy solution. It offers grid independence, cost savings, reduced environmental impact, and reliable power supply, making it a valuable asset for mining companies seeking to optimize their operations in both economic and environmental terms.

However, consideration needs to be given to the local Electrical Cooperative that serves the site. The loss, or partial loss, of a customer like [redacted] could be a big loss to the Coop and could create 'good neighbor' issues. In many cases the Coop is relieved from supplying lower profit energy to the mine and can supply it to more profitable residential or commercial accounts. This discussion should be discussed internally before being addressed with the Coop.

SELF-GENERATION

Using Natural Gas Gensets

On-Site generation of electricity via natural gas generators has gained popularity due to a range of benefits that appeal to both individuals and businesses. This approach offers a level of energy independence and reliability that can be highly advantageous for operations like [redacted]. Here are some key reasons why it has become a popular choice:

1. Energy Independence: Generating your electricity with natural gas generators allows you to be less reliant on the grid. This can be especially important in regions prone to power outages or during emergencies, providing a continuous power supply to critical systems and operations.

2. Cost Savings: Natural gas is often more cost-effective than other fossil fuels, making it an economical choice for electricity generation. The relatively stable price of natural gas can provide long-term budget predictability, particularly for businesses.

3. Environmental Benefits: While natural gas is a fossil fuel, it is cleaner burning than coal or diesel, resulting in lower greenhouse gas emissions and reduced air pollution. Using natural gas generators can help reduce your carbon footprint compared to less environmentally friendly alternatives.

4. Efficiency: Natural gas generators are known for their high energy conversion efficiency, which means they can produce more electricity from the same amount of fuel compared to many other power generation methods. This efficiency can translate into cost savings and reduced resource consumption.

5. Scalability: Natural gas generators come in various sizes, making them versatile for a wide range of applications and can be tailored to meet specific power requirements. In the context of a Micro-Grid as envisioned at [redacted] natural gas 'power stations' could be sized to offset some or all of the site's electrical load. The use of these power stations could not only be a substitute for avoiding the need for a substation from [redacted] Electric Cooperative, but would provide many of these other benefits to the Client.

6. Reliability: Natural gas generators are known for their reliability and durability. They are designed to run continuously for extended periods, making them a dependable source of backup power during outages or as a primary power source in remote locations.

7. Combined Heat and Power (CHP): Natural gas generators can be integrated into combined heat and power (CHP) systems, also known as cogeneration, where they simultaneously produce electricity and capture waste heat for heating or cooling purposes. This dual-use approach maximizes energy efficiency. Co-Generation is one of the major suggestions at [redacted]'s ------- [redacted] location. These power plants could be co-located near the highest load centers to offset electric load and use the recovered waste heat to pre-heat the air used to dry the sand.

The Co-Generation (CG) Option: Traditionally, companies like *Capstone* and others have produced natural gas gensets which offer heat recovery technologies employing air-to-air or air-to-water heat exchangers or use the exhaust itself if safe to do so. Such CG devices are usually located near the heat load, since the transmission of heat via pipes or ducts is more difficult than the transmission of electricity through wires.

Typical efficiencies of these devices range from 30-35%, meaning that for every unit of energy supplied to the unit (measured in BTUs) 30-35% of that energy is converted to electricity, with the rest exiting as heat in the exhaust. This is typical of most generation processes and is why heat recovery is attempted in order to improve economics.

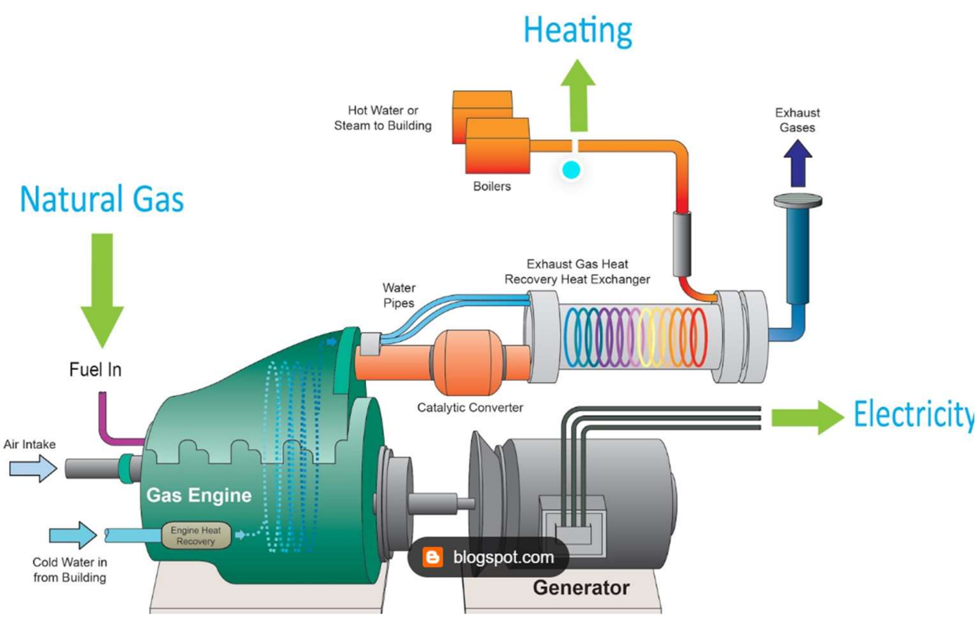


Figure 5 - Typical co-generation plant

AED has been engaged with a new gas generator technology for the last 2 years. A company named *Mainspring* has introduced a novel 'linear generator' in which a shaft slides back and forth between two – 115kW AC generators, forming a 230kW genset. The device delivers better electrical generation (45%) and has the benefit of being 'flex fuel', fired by Natural Gas, Hydrogen and even Anhydrous Ammonia. The company is backed by Bill Gates and others, and is the only company we know of that has arranged to have their Natural Gas generator product qualify for a 40% Investment Tax Credit under the 2022 Inflation Reduction Act (IRA).

For this reason we are proposing that the use of multiple Mainspring generators could be arranged in clusters within a Microgrid environment which would form one or more 'powerhouses' at the -[redacted] facility.

These powerhouses would be located in proximity to the Dryer buildings in order to recover heat from the exhaust. (Whether this is done directly or using heat exchangers will need to be worked out further in an engineering study).

These gensets can be left exposed to the weather (they have their own housing) with the heat recovery insulated, could be housed in either portable 'shipping-type' containers, or could be placed in a more permanent structure. Each of the units is approximately 10' x 4' x 6' tall.

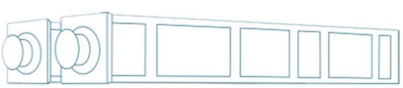
Below is a spec sheet for the Mainspring product.

The Mainspring Linear Generator

Mainspring

Generate cost savings and increased resiliency while meeting your sustainability goals.

Easy Installation
One Fuel Connection
One Electrical Connection



Each package contains two linear generator cores, operating in tandem

Breakthrough design enables an unmatched combination of features and benefits.

High Efficiency
Direct conversion of linear motion into electricity.

Fuel Flexibility
Continuous, adaptive control without mechanical constraints.

Near-Zero NOx
Low temperature reaction without a flame.

Fully Dispatchable
Load-tracking, fast on/off, black start, and islanding.

Turnkey Packaging
Built-in grid tie inverters and auxiliaries.

Performance Specifications

For products delivered in 2022

Outputs	Power (net AC)[1,2] Electrical	250 kW 480 V, 3 Phase, 60 Hz
Inputs	Fuels Input Pressure Water Consumption	Natural Gas, Biogas 8-25 psig (15 psig nominal) None
Efficiency	Electrical (LHV, net AC)[1] Heat Rate (HHV, net AC)	45% 8,416 BTU/kWh
Emissions[3]	NO_x CO VOC Noise	< 2.5 ppm < 12 ppm < 10 ppm < 70 dBA @ 6 feet
Physical	Weight Dimensions (L x W x H)	20 tons 20.5' x 8.5' x 9.5'

Environment	Temperature Range Humidity	-30 to 50 C 0 to 100%
Grid-Parallel	Load Tracking Power Output Range (net AC)	20 kW/second 0-250 kW
Backup[4]	Grid Parallel to Island Transfer Maximum Step Load Building Soft Start Capability	< 1 sec 120% nameplate KVA Yes
Other	• UL 2200 package • UL 1741 SA grid-tie inverter	• Remote monitoring • Secure customer portal

[1] Measured according to ASME PTC 19.1 at ASME PTC 50 ambient conditions (15 C, 1 atm).
[2] Nameplate capacity is reduced by 10 kW if operated in the South Coast AQMD.
[3] Emissions reported as volumetric dry and corrected to 15% O_2.
[4] Performance based on purchase with backup kit and additional site relays and protective equipment.

About Mainspring Energy

Driven by its vision of the affordable, reliable, net-zero carbon grid of the future, Mainspring is the leading manufacturer of linear generators, delivering onsite, dispatchable, fuel-flexible power for commercial and industrial customers, utilities, municipalities, and microgrid developers.

3601 Haven Avenue
Menlo Park, CA 94025
mainspringenergy.com
sales@mainspringenergy.com

Confidential Business Information

There are several strategies that could be employed when trying to decide the sizing for co-generation.

1. **Size to total load of the site.** This would provide for the ability of the current site to go 'off-grid' if desired and would eliminate current demand (power) charges from the Coop. Heat would be used to pre-heat the dryer air. As expansion occurs however, additional power would be needed from the grid.

2. **Size to future expansion of the site.** Similar to #1, this allows future expansion and current loads to be self-generated.

3. **Size to augment current grid power** to eliminate the need for a substation investment. This can be looked at as an option to the substation choice, as it would negate the need for additional power or energy from the Coop. In other respects, the site would remain fully connected and reliant on the Coop for power and energy. The amount of energy and power required from the substation is assumed to be the additional projected future loads, since the grid can already support existing loads.

4. **Size to some other value**, such as the aggregated loads around Dryer #4 & 5 and Wet #2.

These strategies would result in the Powerhouse sizes shown in the table below.

	Gas Energy Requirements - for Co-Generation:		*Using Mainspring 230kW units at 45% efficiency*				
			Splits into:				
Strategy:	**Elect. Energy (kWhrs/yr)**	**Gas BTUs Req'd**	**elect btus/yr (45%)**	**heat btus/yr (55%)**	**No units**	**% of Site's Heat Load**	**Gen kW**
Single unit -	2,001,000	15,176,473,333	6,829,413,000	8,347,060,333	1		230
1	40,309,995	305,728,915,024	137,578,011,761	168,150,903,263	20	16.3%	4,633
2	80,185,515	608,162,581,158	273,673,161,521	334,489,419,637	40	32.5%	9,217
3	39,875,520	302,433,666,133	136,095,149,760	166,338,516,373	20	16.1%	4,583
4	12,232,993	92,780,458,923	41,751,206,515	51,029,252,407	6	5.0%	1,406

Table 8 - Electric production and waste heat for different sizing strategies.

For example, to accomplish Strategy #3 above (self-generate enough energy to cover the forecasted future increase) would require the site to purchase 302,433,666,133 BTUs, or 302,222 Decatherms of Natural Gas (where 1,000,700 BTUs = 1 Decatherm or DTH, or 100,000 BTUs = 1 Therm). When run through the co-generator that gas would produce 39,875,520 kWhrs of electricity per year (3413 BTU/kWhr), and 166,338,516,373 BTUs of waste heat. That amount of waste heat would be equal to 16.1% of the site's current heat load.

It is here that the value of self-generation using heat recovery can be seen. Instead of buying kWhrs from the grid where the value of the waste heat used to produce them is lost to the electricity buyer, self-generation with heat recovery uses virtually ALL of the BTUs available in the gas purchased.

Costs of Self-Generation:

With respect to the Microgrid and Self-Generation, it is assumed that management will decide to purchase the system and own it outright. An alternative, however, is to enter into a Power Purchase Agreement (PPA) with an Independent Power Producer (IPP) who would own and operate the generation equipment and charge the project by the kilowatt hour, like the electric company. Each option has its own merits. Regardless of the option selected, however, the operating cost of the system can be determined by modeling the capital expenditure plus annual operating costs and adding costs of financing. That is the process this report uses to determine the cost of energy for the options shown. To do this, AED uses a proprietary software named FOCUS© which can model each of these energy production scenarios.

CapEx:

Based on recent discussions with the product manufacturers and distributors, the system costs (Capex) for a Microgrid with Self-Generation via Natural gas using the Mainspring gensets has been derived as follows:

- Mainspring 230kW Units - $730,000/unit less $292,000 Investment Tax Credit ($438,000 each)
- Microgrid controls and switchgear – $750K/1st MW, + $150K/addt'l MW
- Heat Recovery Legs - $.5M per installed location
- Balance of Plant (Data Control, piping, etc.) - $.3M/MW

  All of the above would be entitled to a project-wide deduction of either a 30 or 40% ITC and depreciation via MACRES, Schedule 179 or 20 year straight line methods.

Given the above, the 4 strategies listed above would create Capital Outlays of:

Table 9 - Projected CapEx of Co-Gen Options

Strategy:	Gen kW	CapEx
1	4,633	$18,390,795
2	9,217	$35,500,613
3	4,583	$18,209,818
4	1,406	$6,195,552

- *Notes:*
- *Strategy #1 – 2 locations, near dryers.*
- *Strategy #2 - placed at 3 sites near dryers.*
- *Strategy #3 – 2 locations, near dryers.*
- *Strategy #4 – 1 location at Dryer 4&5*

OpEx:

The Operating Cost of a natural gas co-generation facility is comprised of 3 major costs:

1. Amortization Costs of the equipment (can be considered with or without financing)
2. Operating and Maintenance costs
3. Cost of the gas used to run the equipment

These costs are shown in Table 9 below. The amortization of the equipment has been calculated based on a 20 year useful life of the gensets (provided while under maintenance agreement).

An estimate of $.015/kWhr was suggested as a close approximation of actual Operational Expenses per year for Mainspring units. This includes a rebuild of the microturbines every 7 years.

Management has provided current natural gas costs, as shown in Figure 5 below. Natural Gas prices fluctuate monthly. A value of $.488/Therm has been used ($4.88/DecaTHerm).

Natural Gas Usage and Cost per ton Shipped and Produced

DTH used per tons shipped CM vs PM

	CM DTH	PM DTH	Change		DTH/ton shipped	DTH/ton shipped	Change	
	Sep-23	Aug-23	DTH	%	Sep-23	Aug-23	Therms	%
	38,436	77,658	(39,222)	-50.5%	0.19	0.22	-0.03	-14%
Total Tons Shipped	199,708	347,122	(147,414)	-42%				

DTH used per dry ton produced CM vs PM

	CM DTH	PM DTH	Change		DTH/dry ton produced	DTH/dry ton produced	Change	
	Sep-23	Aug-23	DTH	%	Sep-23	Aug-23	Therms	%
	38,436	77,658	(39,222)	-50.5%	0.17	0.17	0.00	2%
Total Dry Tons Produced	224,587	461,427	(236,840)	-51%				

Natural Gas Cost per tons shipped CM vs PM

	CM $	PM $	Change		Gas cost/ton shipped	Gas cost/ton shipped	Change	
	Sep-23	Aug-23	$	%	Sep-23	Aug-23	$	%
Total Gas Cost	223,245	348,341	(125,095)	-35.9%	$ 1.12	$ 1.00	0.11	11%
Cost per dth	5.81	4.49	1.32	29.5%				

Figure 6 - Current Natural Gas costs at-[redacted]

Given the above Capital Expenditures and the actual and projected energy generation, we can predict the cost of energy produced by the Co-Generation facilities to be as follows:

Cost of Energy for Strategies, per kWhr:						
		Amortized	**O&M**	**Cost of Gas ($/Th)**		**Value of 'Free'**
Strategy:	**kWhrs/20yr**	**CapEx**	**.018/kWhr**	**$0.488**	**Total**	**Waste Heat $/yr:**
1	806,199,893	$0.023	$0.018	$0.037	$0.078	$820,576
2	1,603,710,293	$0.022	$0.018	$0.037	$0.077	$1,632,308
3	797,510,400	$0.023	$0.018	$0.037	$0.078	$811,732
4	244,659,868	$0.025	$0.018	$0.037	$0.080	$249,023

Table 10 - Cost of Self-Generation using Co-Generation (Cost of Gas taken as $.488/therm)

The cost of each kilowatt-hour in the Self-Supply strategies is slightly higher than the $.0638 (peak) or $.0438 (off peak) current electrical pricing from [redacted] Electric. However, the following is also true:

1. There would be no 'demand' charges for power for the portion of the plant powered by self-generation. At a combined Power + Distribution cost of $12.35/kW-month, and an average CURRENT demand of 7,150 kW-months, ***the demand savings are equivalent to $88,300/month*** (assuming strategy #2 used). This is equal to $1,059,624 of saved demand charges each year (assuming no escalation in prices).

2. The value of the waste heat that would be supplied by the co-generation plants would contribute between $249,023 and $1,632,308 per year, depending on the strategy employed. ***If Strategy #2 was employed, the combined savings between Demand charges and Waste heat would equal $2,691,932 per year.***

3. Note that in both of the above benefits NO escalation in power or gas costs is assumed. The forecasting of such escalations is beyond the scope of this report. As a reminder, a 4% annual increase results in a doubling of the costs (in this case the savings) over 20 years.

4. This report does not include other intrinsic values of self-supply, such as resilience to outages and future spikes in market pricing.

5. Also of note is the fact that the economics of self-generation are relatively indifferent to scale. The selection of a Strategy other than #2 (supplying the entire site) would derive similar economics.

SOLAR GENERATION

Solar Input Analysis

When analyzing how much solar PV could be utilized on the site, several factors come into play:

1. Land availability
2. Ability to export power/energy based on state or utility programs
3. Absorption by the on-site load
4. Financial Constraints

Array Sizing: The Client has suggested two areas of land where PV arrays could be located. These are indicated as Phase 1 and Phase 1.5 on the site diagram below. They contain 16.5 and 26.5 acres of land respectively. Additional land is available if needed.

Based on the available land area a computer analysis using the *Helioscope* program shows that two arrays of 4.5 and 8.8 MW could be located on the sites. The combination of arrays would produce some 21,118,000 kWhrs of energy each year.

The actual Helioscope summaries are depicted below and shown in full in the Appendix.

	Size (AC kW)	**Production (kWhrs/yr)**	**Size (Acres)**
Lower Array ("Phase 1")	4.5 MW	7,018,000	~ 16 acres
Upper Array ("Phase 2")	8.8 MW	14,100,000	~ 31 acres

Table 11 – Potential Solar Arrays

This report considers the land availability to size the arrays, and then constrains the use to the on-site load.

ASSOCIATED ENERGY DEVELOPERS — Annual Production Report produced by AED HelioScope

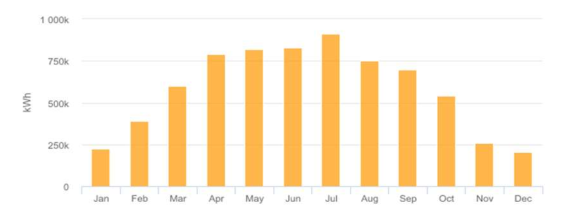
Design Lower Array [redacted]

Report	
Project Name	[redacted]
Project Address	
Prepared By	AED HelioScope helioscope@assocenergy.com

System Metrics	
Design	Design Lower Array
Module DC Nameplate	5.42 MW
Inverter AC Nameplate	4.50 MW Load Ratio: 1.20
Annual Production	7.018 GWh
Performance Ratio	78.5%
kWh/kWp	1,295.0
Weather Dataset	TMY, 10km Grid (43.95,-90.45), NREL (prospector)
Simulator Version	3411204795-7eea9ab956-49b6fb59f2-f97935bb16

Project Location

Monthly Production



Sources of System Loss

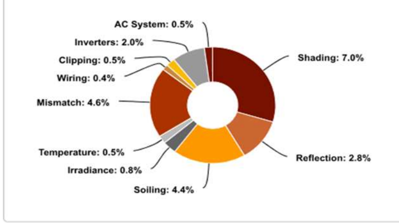


Figure 7 – Lower Phase 1 area solar array

ASSOCIATED ENERGY DEVELOPERS — Annual Production Report produced by AED HelioScope

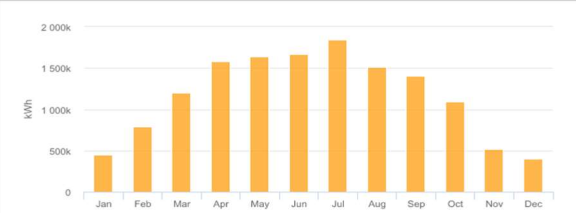
Design Upper Array [redacted]

Report	
Project Name	[redacted]
Project Address	
Prepared By	AED HelioScope helioscope@assocenergy.com

System Metrics	
Design	Design Upper Array
Module DC Nameplate	11.0 MW
Inverter AC Nameplate	8.80 MW Load Ratio: 1.25
Annual Production	14.10 GWh
Performance Ratio	77.9%
kWh/kWp	1,284.5
Weather Dataset	TMY, 10km Grid (43.95,-90.45), NREL (prospector)
Simulator Version	3411204795-7eea9ab956-49b6fb59f2-f97935bb16

Project Location

Monthly Production



Sources of System Loss

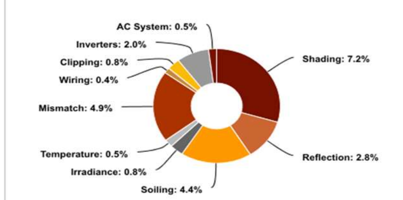


Figure 7 – Upper Phase 1.5 area solar array

Figure 8 - Potential Solar PV Locations

Exporting of Solar Energy:

In February 2004, the -[redacted] Public Service Commission adopted interconnection standards for distributed generation (DG) systems up to 15 megawatts (MW) in capacity. All investor-owned utilities (IOUs) and municipal utilities are required to abide by the standard provisions. Electric cooperatives are encouraged -- but not required -- to adopt the state standards. The [redacted] Electric Cooperative should be contacted in the next phase of the study to understand what kind of Net Metering would be allowed from this site. *At this time no mention or inquiry as to Net Metering has been done with the utility wthout the permission of the Client.* Given permission by the Client AED could initate a discussion with the Coop about this question and rework the numbers.

On-site Use of Energy (Micro-grid):

The production of the potential solar arrays compares favorably with the site's entire current electrical load of 40,309,995 kWhrs/yr (52.4%) or future load of 80,185,515 kWhrs/yr (26.3%). The balance of the energy would be drawn from the Coop through the grid, or self-generated within the Microgrid if available.

The creation of solar generation should be considered in context with a 'micro-grid' which could be developed on the site. Such a system would incorporate other generation, including gas co-generation efforts. The microgrid would then manage the mix of solar, gas generation and grid power in an automated fashion.

Note however, that unless Net Metering or another storage method is provided, not all of this production would be useful. In fact, without Net Metering or the ability to export and receive value for the energy, nearly 8.5Million kWhrs per year from these arrays would be 'stranded'. If no storage is available (see section below) or net metering available, then the arrays would need to be sized in order to only produce electricity that would be absorbed on the site and not exported or stranded.

The FOCUS software was used to compare the 15 minute Time-of-Use load data obtained from the electric utility to the 15 minute solar AC power generated by the arrays, using 20 year Typical Mean Year (TMY) insolation data for this site. *In order to not 'strand' any solar energy, the arrays could not exceed 7.3MW AC in size (two arrays combined).*

The following Proforma Income Statement shows the value of the Solar Energy produced as it displaces $.066/kWhrs at typical installation prices (this is not a quotation). A 'placeholder' for financing was used, including a 30% downpayment, a 6.5% Interest Rate and a 20 year fully amortizing loan. Assumes the 30% Investment Tax Credit and 5 year MACREs depreciation are used.

ASSOCIATED ENERGY DEVELOPERS

FOCUS

25-YEAR FINANCIAL PROFORMA : SMARTSAND - , Oakdale, WI

Notes: BTM NM Solar PV w/Roof Replacement
Prepared For:
Prepared By: Brian Kuhn, Founder, CEO
Contact Info: 1(888) 800-2381 | Brian.Kuhn@AssocEnergy.com
Report Date: 11/6/2023 16:08

	Source 1	Source 2	Source 3	Energy Storage	Ancillary Svc.	Totals
Generation Type:	Ground SolarPV	Ground SolarPV			N/A	
Size (dc):	5,420.000 kWdc	11,000.000 kWdc				16,420.000 kWdc
Size (ac):	4,500.000 kWac	8,800.000 kWac				13,300.000 kWac
Net Output:	7,018,239 kWh	14,095,764 kWh				21,114,003 kWh
Cost ($):	$9,558,783.00	$19,286,397.00				$28,845,180.00
Cost ($/W):	$1.764 /Wdc	$1.753 /Wdc				$1.757 /Wdc
Tax Ineligibles:	$0.00	$0.00				$0.00
Investment Tax Credit:	$2,867,634.90	$5,785,919.10				$8,653,554.00
Depreciation Cash Value:	$2,274,990.35	$4,590,162.49				$6,865,152.84

1 Year	2 Src1: SolarPV - M1 Exported Revenue at Grid Rate of: $0.00000 /kWh	3 Src2: SolarPV - M1 Exported Revenue at Grid Rate of: $0.00000 /kWh	4	5	6	7 Utility Incentive Revenue Includes Solar RECs avg. $0.06600 /kWh	8	9 Depreciation and Fed ITC Depreciation at 28.0% Tax Rate 0	10 Gross Revenue	11 Site Lease / Site Purchase	12 Insurance Coverage $4.38/kWdc with 1.5% escalator	13 Operations & Maintenance $2.14/kWdc with 1.5% escalator Includes Inverter Budget	14 Miscellaneous Expenses 000	15 Asset Management	16 Offtake & Other Costs	17 Down Payment/ Interest Reserve 30.0% Down Payment	18 PILOT / Property Taxes	19 Total Net Revenue (before financing)	20 Total Payments (P & I) 70.0% LTV 6.50% Interest Loan Principal of $20,191,626.	21 Debt Service Coverage Ratio 1.25 (suggested minimum)	22 Annual Net Cash Flow	23 Cumulative Net Cash Flow
0																-$8,653,554		-$8,653,554			-$8,653,554	-$8,653,554
1						$1,393,524		$13,682,642	$15,076,166		-$72,000	-$35,091						$14,969,075	-$1,032,297	1.25	$13,936,778	$5,283,224
2						$1,386,557		$734,426	$2,120,983		-$73,280	-$34,916						$2,012,787	-$1,032,297	1.24	$980,490	$6,263,713
3						$1,379,589		$440,656	$1,820,245		-$74,583	-$34,741						$1,710,920	-$1,032,297	1.23	$678,623	$6,942,336
4						$1,372,621		$264,393	$1,637,015		-$75,910	-$34,567						$1,526,537	-$1,032,297	1.22	$494,240	$7,436,576
5						$1,365,654		$264,393	$1,630,047		-$77,261	-$34,395						$1,518,392	-$1,032,297	1.21	$486,094	$7,922,671
6						$1,358,686		$132,197	$1,490,883		-$78,636	-$34,223						$1,378,024	-$1,032,297	1.21	$345,727	$8,268,397
7						$1,351,718			$1,351,718		-$80,037	-$34,052						$1,237,630	-$1,032,297	1.20	$205,333	$8,473,731
8						$1,344,751			$1,344,751		-$81,462	-$33,881						$1,229,407	-$1,032,297	1.19	$197,110	$8,670,840
9						$1,337,783			$1,337,783		-$82,914	-$33,712						$1,221,157	-$1,032,297	1.18	$188,860	$8,859,701
10						$1,330,816			$1,330,816		-$84,392	-$33,543						$1,212,880	-$1,032,297	1.17	$180,583	$9,040,283
11						$1,323,848			$1,323,848		-$85,897	-$608,076						$629,875	-$1,032,297	0.61	-$402,422	$8,637,862
12						$1,316,880			$1,316,880		-$87,429	-$33,209						$1,196,242	-$1,032,297	1.16	$163,945	$8,801,807
13						$1,309,913			$1,309,913		-$88,989	-$33,043						$1,187,881	-$1,032,297	1.15	$155,583	$8,957,390
14						$1,302,945			$1,302,945		-$90,578	-$32,877						$1,179,490	-$1,032,297	1.14	$147,193	$9,104,583
15						$1,295,978			$1,295,978		-$92,195	-$32,713						$1,171,069	-$1,032,297	1.13	$138,772	$9,243,355
16						$1,289,010			$1,289,010		-$93,842	-$32,550						$1,162,618	-$1,032,297	1.13	$130,321	$9,373,676
17						$1,282,042			$1,282,042		-$95,519	-$32,387						$1,154,137	-$1,032,297	1.12	$121,839	$9,495,515
18						$1,275,075			$1,275,075		-$97,226	-$32,225						$1,145,624	-$1,032,297	1.11	$113,326	$9,608,841
19						$1,268,107			$1,268,107		-$98,965	-$32,064						$1,137,079	-$1,032,297	1.10	$104,781	$9,713,623
20						$1,261,139			$1,261,139		-$100,735	-$31,903						$1,128,501	-$1,032,295	1.09	$96,206	$9,809,829
Subtotals:						$26,546,636		$15,518,707	$42,065,343		-$1,711,852	-$1,244,166				-$8,653,554		$30,455,771	-$20,645,941	1.14	$9,809,829	$9,809,829
											Additional Years' Performance											
21						$1,254,172			$1,254,172		-$102,537	-$31,744						$1,119,891			$1,119,891	$10,929,720
22						$1,247,204			$1,247,204		-$104,373	-$31,585						$1,111,247			$1,111,247	$12,040,966
23						$1,240,237			$1,240,237		-$106,241	-$31,427						$1,102,568			$1,102,568	$13,143,535
24						$1,233,269			$1,233,269		-$108,144	-$31,270						$1,093,855			$1,093,855	$14,237,389
25						$1,226,301			$1,226,301		-$110,082	-$31,114						$1,085,106			$1,085,106	$15,322,495
Totals:						$32,747,819		$15,518,707	$48,266,526		-$2,243,229	-$1,401,306				-$8,653,554		$35,968,437	-$20,645,941			$15,322,495

Column groups: Revenue (Cash Basis) (1–9); Gross (10); Operating Expenses (11–18); EBITDA (19); Financing (20–21); Results (22–23).

Key Financial Metrics

Internal Rate of Return (IRR)

20-Year Unlevered IRR: *15.94%*
25-Year Unlevered IRR: *16.29%*

Project Notes

- Ground SolarPV modeled using 30% ITC. Ground SolarPV modeled using 30% ITC. Depreciation modeled at 28% Tax Bracket. Year One Tax Benefit ROIC of 158.12%.

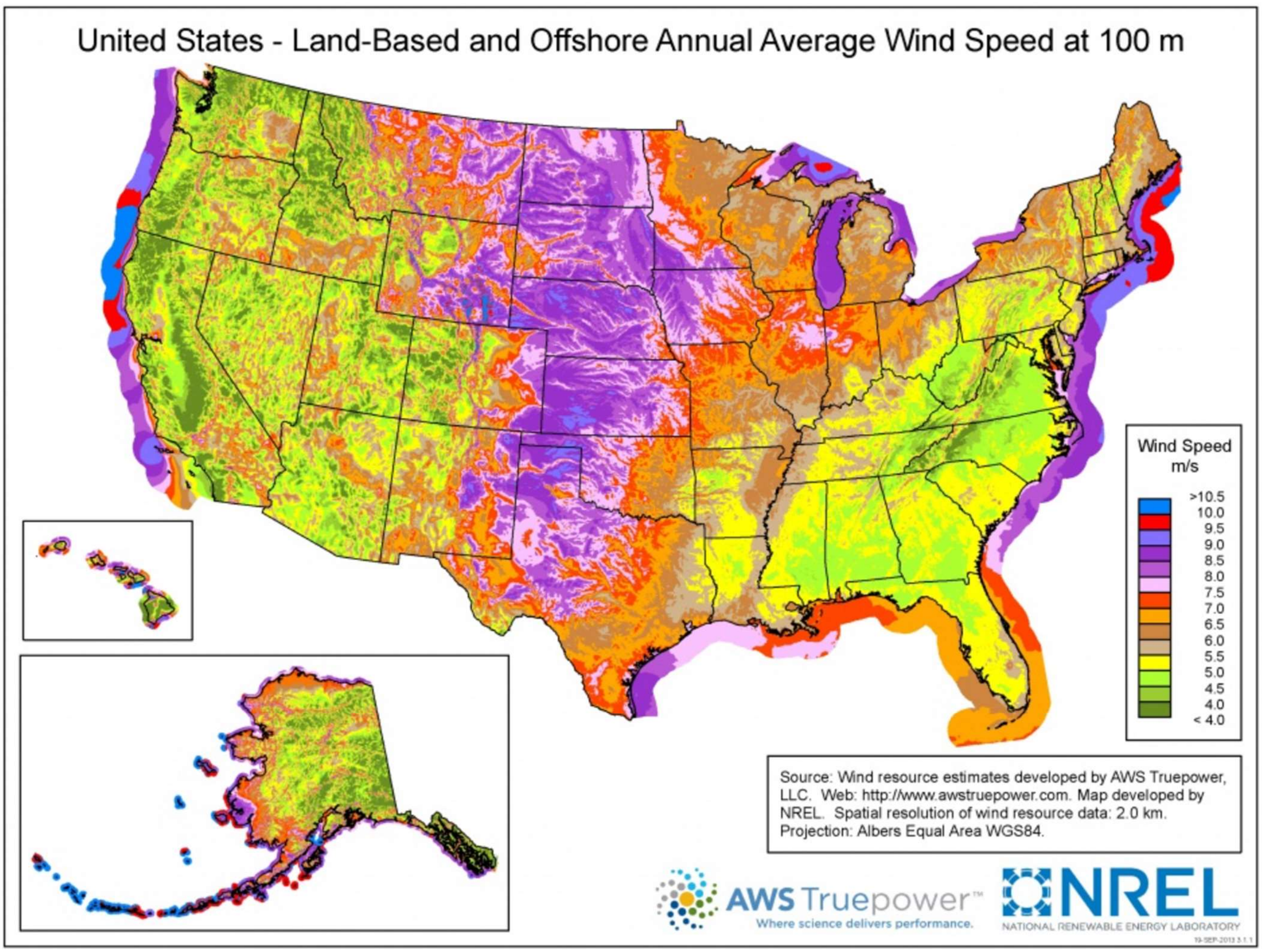
Figure 9 - Economics of Solar Arrays Using $.066 blended cost of energy

WIND ENERGY GENERATION

The study looked at the potential of using Wind energy to supplement the site's electrical loads.

In general, the site appears to be in a region of modest wind resources. Although no met tower data has been collected at the actual site, the wind map from the National Renewable Energy Laboratory was used to estimate the wind potential. At a 100M hub height, which is considered typical for today's industrial wind turbines, the average annual wind speed ranges from 6-7 meters/second.

This is considered to be a marginal-to-good wind resource for a Distributed Generation Wind turbine site.



Modern wind turbines range in size from 1.5 to over 4.5MW in output at rated wind speeds of (typically) 14 m/s. Capacity faxctors of these size machines run between 30-35%, meaning that a yield of 4.2 to 12.6 MWhrs (4,200,000 – 12,600,000 kWhrs) per year of power could be produced for each machine.

The production of a single 1.5MW wind turbine compares favorably with the site's entire current electrical load of 40,309,995 kWhrs/yr (10.4%) or future load of 80,185,515 kWhrs/yr (15.7%).

The pros and cons of wind energy can be summarized as follows:

Pros:

- Proven 20+ year production
- Copious energy output in known wind regions
- Energy production in the range of $.05 - $.07/kW/hr

Cons:

- Difficulty in permitting in Suburban areas
- Variable output requires storage or net metering programs
- Reliance on grid for storage or backup works against micro-grid 'independence'
- Long term installation – heavy, immovable concrete footings
- 1 year+ on-site met tower study for bankability

At the [redacted] site a small wind 'park' of at least two – 3MW machines could be considered (6MW total). The estimated cost of such an installation would be approximately $12.8M USD. Distributed wind generation sites such as these typically exhibit unlevered Internal Rates of Return on the order of 13-16%. Such an installation could provide up to 16,800,000 kWhrs/yr, or 41% of the current site load.

ENERGY STORAGE

Electrical energy storage is gaining popularity within the renewable energy field as a way of providing more of a 'base load' of electrical power. The problem with Solar and Wind power are that they are not steady, and cannot be counted on at night or in cloudy weather. The addition of electric storage remedies this situation to a large extent.

The best applications for electrical energy storage are those applications where power and energy use occurs in 'spikes'. The spikes, which result in higher demand costs, are mitigated, thus saving energy and assuring resilience. In short, inertia is added into the site's energy balance.

Unfortunately, the -[redacted] site does not appear to offer the profile needed for electrical energy storage to be effective. There are so many loads, and the loads are being used so often over the day, that battery (or other formats of energy storage) are largely ineffective and cost prohibitive.

Conclusions:

After having gone through the process of producing the report, AED is in a position to offer some conclusions and findings for the benefit of [redacted] management, along with a 'roadmap' of action items that it believes should be implemented in order. Those conclusions are listed below and are backed up by the metrics contained in the full report.

1. *Financially viable alternatives to spending $1.5M+ on a new transformer or substation for the* [redacted] *Electric Coop do exist.* Instead of spending money to allow more power to flow into the site, investments can be made to reduce the need for additional energy by means of either self-generation of renewable solar energy in a 'Microgrid' environment.
2. *Both the solar and self-supply alternatives should be viewed as viable investments* that either save or generate energy (kWhrs) or power (kW) at lower overall prices than received from [redacted]. Although the cost of energy generated from self-supply is slightly higher than the current cost of electricity from the Coop ($.078 vs. $.068/kWhr), the savings in Demand Charges (over $1,050,000/yr) and Value of Waste Heat Recovery ($1,630,000/yr) alone make the co-generation self-supply concept viable.
3. *The co-location of large electrical plus dryer loads is an ideal use case for co-generation via natural gas generation.* Individual 'powerhouses' could be located on the site at large load centers, each operating under a collective 'Microgrid' environment.
4. *The Co-Generation concept can be introduced in various sizes, or stages, over time.* Management could decide to employ self-supply at the largest current use load center at the site (Heating #4 & 5 and Water #2 buildings) and then add additional self-generation later. The Microgrid/generation sources could be a partial or total solution to the Client's 5 year growth plan.
5. *The overall energy policies that the Client decides to employ can be 'staged' or phased.* Each would be a component in an overall 'Microgrid' to be established at the site. Over the next 5 years the need for a new substation would be eliminated. Discussions should be held by management as to the actual required timing of the expansion load requirements. For instance, during next year alone the expansion load appears to be nearly 15,000,000 kWhrs, or a 36% increase over the entire site load in one year. Perhaps this load could be 'phased in' in order to allow other self-generation measures to take effect.
6. *The timing of implementing any self-*generation options needs to be discussed in light of the need for the [redacted] substation. Solar projects of this scale will typically require 9-16 months in order to design, permit, interconnect and operate. Almost half- of that time is taken by the local utility to allow interconnection, as the utilities are not usually happy to have their energy sales taken away. Of course, if the solar arrays are kept totally behind the meter (no exported energy) then the interconnection problem goes away. But this would require the arrays to be sized substantially smaller than proposed (+/- 7MW AC) so that excessive solar energy is not 'stranded'.

The creation and implementation of a Microgrid utilizing natural gas generators could also take up to a year or more to permit, build, and (perhaps) interconnect. The Mainspring generators suggested in the report have lead times as long as 10 months for delivery. Although the Mainspring units have been suggested due to efficiencies, additional co-gen units are available from sources such as *CapStone* with shorter deliver schedules.

The timing of the options is important, as it may be found that rescheduling part of next years' projected expansion requirements would allow self-generation the time to 'catch up' with the expansion.

7. *Solar PV can be a profitable investment at the site. Management has proposed 2 locations at the site which could be used to construct a total of 13.3MW of solar power (or more if additional land is available).* Based on the cost of energy at the site (and ignoring any demand savings, which are unpredictable) such an investment would result in a 15% unleveraged Internal Rate of Return. This assumes that net metering is allowed by [redacted] If not, the systems need to be downsized to just 7MW to avoid 'stranding' excessive amounts of energy.
8. *The application of solar PV arrays, while making an attractive investment on their own in the form of energy costs, do NOT replace the need for additional power requirements.* Because the sun is not always available, the solar arrays could not be counted on to provide POWER needed for the facilities 24 x 7. If only the solar options were selected the company would still require the need of the substation from [redacted] to provide peak power.
9. *The specifics of system designs, including sizing and strategies, should only be implemented after discussions are had with* [redacted] *Electric Cooperative* in order to ascertain the existence of or amount of Net Metering capability, they would be willing to provide. In Wisconsin, Net Metering is an option for a Cooperative. This report did not contact [redacted] so as to not 'tip the hand' of management.
10. *Both solar and self-generation have large tax benefits associated with them*. If the Client is not in a position to utilize these benefits themselves, it is suggested that a form of Independent Power Producer (IPP) relationship be struck with outside investors.
11. Both solar and self-generation would provide meaningful ESG aspects to the Client. The value of these benefits was not quantified in this report.

Suggested Next Steps:

6. Internal Discussions about the report and potential questions for AED.
7. Discussion about options for Net Metering with [redacted] Electrical Coop.
8. Creation of a 'Front End Engineering Design' (FEED) for the project to further detail system designs and electrical engineering. The Microgrid concept would be detailed in this stage as well, and could extend to other 'phases' of energy projects as they are brought on-line.
9. The first and most obvious place to start implementation would be to create co-generation of electric and heat at the Dryer 4&5 / Wet #2 buildings. The electric loads and heat loads

are in close proximity to each other in this location and represent a large portion of the site's energy load (30% of current case, 15% of future case). Such a phase could produce over 12,000,000 kWhrs/year and 5% of the site's total heat load. This also creates a project which is relatively compact, and could be implemented quickly.

10. Unless the company wishes to own the solar arrays themselves (and have the tax appetite for the Investment Tax Credits and Depreciation write-offs), we suggest that the company investigate a Power Purchase Agreement option with a solar developer for the solar PV option. The solar arrays would need to be explored with [redacted]- if they are to interconnect with the grid.

Appendices:

The following is from the national Database of State Incentives for Renewables & Efficiency® (www.dsireusa.org)

From DSIRE:

In February 2004, the Wisconsin Public Service Commission adopted interconnection standards for distributed generation (DG) systems up to 15 megawatts (MW) in capacity. All investor-owned utilities (IOUs) and municipal utilities are required to abide by the standard provisions. Electric cooperatives are encouraged -- but not required -- to adopt the state standards. The rules categorize DG systems by capacity and provide for several levels of interconnection review, as follows:

- Category 1: 20 kilowatts (kW) or less
- Category 2: larger than 20 kW, but no larger than 200 kW
- Category 3: larger than 200 kW, but no larger than 1 MW
- Category 4: larger than 1 MW, but no larger than 15 MW

The PSC has published two sets of standard forms for interconnection, available on the program web site. One set pertains to systems smaller than 20 kW while the second set applies to larger systems up the maximum size of 15 MW. The PSC also maintains a list of utility interconnection contacts on their Distributed Generation web site. The Wisconsin Distributed Resources Collaborative (WIDRC) has published a set of interconnection guidelines that offer some additional details on the interconnection process.

Generally speaking, Wisconsin's interconnection requirements become more stringent as the system size increases. The rules apply to all public utilities. The 20-kW dividing line between Category 1 and Category 2 installations corresponds to the maximum individual system capacity allowed under the state's net-metering rules. Systems that qualify for net metering are not considered commercial ventures that require commercial liability insurance.

Minimum liability insurance of at least $300,000 per occurrence is required for systems 20 kW and smaller (Category 1) with higher amounts for larger systems based on the category of review under which they fall. However, the law also permits applicants to prove financial responsibility using a negotiated agreement with the utility in lieu of the insurance requirements. Additionally, Category 2-4 facilities must name the utility as an additional insured party in the insurance policy.

Application and study fees vary by category, but systems 20 kW and smaller are not required to pay any fees for application reviews, engineering reviews, or distribution system studies. Facility owners are permitted to file an appeal with the PSC if they believe they are being held to unreasonable requirements, but the rules provide do not provide any guidance on how such appeals will be addressed. In practice, such an appeal would be addressed as a complaint under s. 196.26, Wis. Stats.

Net Metering:

The Public Service Commission of Wisconsin (PSC) issued an order on January 26, 1982, requiring all regulated utilities to file tariffs allowing net metering to customers that generate electricity with systems up to 20 kilowatts (kW)* in capacity.

Eligibility and Availability

The order applies to investor-owned utilities and municipal utilities, but not to electric cooperatives. All distributed-generation (DG) systems, including renewable energy and combined heat and power (CHP) systems, are eligible. There is no limit on total enrollment.

Net Excess Generation

The PSC has not adopted administrative rules for net metering.** Utilities' net-metering tariffs contain some variations. Customer net excess generation (NEG) is generally credited at the utility's retail rate for renewable energy, and at the utility's avoided-cost rate for non-renewable energy. NEG credit is carried over to the customer's next bill. If NEG credit exceeds $25, then the utility must issue a check for the amount, payable to the customer.

In December 2011, the PSC approved a process for Xcel Energy to reconcile NEG credits to customers on an annual basis at the avoided-cost rate.

Investor-Owned Utility Net Metering Tariffs

For more information on net metering, refer to the applicable utility net metering tariffs listed below. The Public Service Commission also maintains a listing of utility tariffs that can be used to access your utility's net metering tariff if it is not listed here.

- Northern States Power Company d/b/a Xcel Energy - System size limit: 120% of average annual consumption; NEG credits roll over monthly at the retail rate and are compensated at the end of calendar year at the avoided cost rate.
- Wisconsin Electric Power Company d/b/a We Energies - System size limit: 300 kW; NEG credits reconciled monthly at the Customer's Buy-Back Energy Rate ($0.04642 per kWh).
- Madison Gas and Electric - System size limit: 100 kW; NEG credits roll over monthly at the Energy Credit Rate.
- Wisconsin Public Service Corporation - System size limit: 20 kW; NEG credits roll over monthly at a rate that includes energy, capacity, and transmission costs.

** Some utilities allow net metering for systems larger than 20 kW. In these cases, excess generation rates, carry-over processes, and capacity limits vary by utility. These provisions are specified in the utility tariffs.*

*** Subsequent PSC decisions issued June 21, 1983 in docket numbers 05-ER-11, 05-ER-12 and 05-ER-13, further implemented Sections 201 and 210 of the federal Public Utility Regulatory Policy Act of 1978 (PURPA). These decisions were confirmed by an order issued September 18, 1992, in docket number 05-EP-6. This last order addresses net metering as it applies to Wisconsin's investor-owned utilities.*