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ECONOMIC ANALYSIS OF A 3MW BIOMASS GASIFICATION POWER PLANT

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Abstract
An economic and technical analysis of the use of separated wood biomass as a feedstock for gasification for a 3 MW power plant was conducted for the Miramar Landfill, located in San Diego County, CA. The method to generate combustible gas from the biomass is based on a dual-fluidized bed gasification process which operates at atmospheric pressure with air and produces a high quality producer gas with little nitrogen. The objective of the study was to determine the economic feasibility of the proposed biomass power system in terms of the potential revenue streams and costs. Major economic considerations in the analysis include feedstock, capital, and operating costs. Regulatory issues, inclusive of production credits, renewable energy incentives, and feed-in tariffs are addressed as significant economic inputs. The Miramar landfill, in San Diego County, CA is representative of a typical existing urban landfill, with corresponding feedstock and some market for separated wood biomass. The economic analysis of the proposed 3MW gasification power plant indicates that it would not have a net positive NPV under the current urban scenario. More likely successful candidates are landfill sites in more rural areas or urban sites, where new landfills are being developed or where the landfill is no longer operational but has become a transfer station. In all cases waste heat sales are a critical element in determining economic viability

Introduction
The economic and technical feasibility of using separated biomass feedstock from the Miramar Landfill, located in San Diego County, CA to generate 3 MW of power was examined. The objective of the study was determining the economic viability of using an advanced gasification method to process some of the 1.4 million tons of waste is disposed of at the Miramar Landfill every year. The goal of this study was to determine whether this project has a positive net present value (NPV) based on the potential revenue streams and operational costs and site specific parameters associated with the Miramar Landfill.

Technical Background
Thermal gasification is the chemical conversion at high temperatures of materials containing carbon atoms into a producer gas which can be used to fuel an engine/generator to produce power. This gas is composed mainly of hydrogen, carbon monoxide, methane, carbon dioxide, and water. In addition to power generation, energy in the hot exhaust gases can be captured to provide process heat. The reactions involved in the gasification of biomass to produce gas are endothermic. That is, they require a net input of energy. The energy required is obtained by oxidizing (burning) a portion of the biomass in exothermic reactions. The overall process is exothermic. In some plant designs, both the gasification and oxidation reactions are carried out in different sections of the same reaction chamber. Such a process is referred to as a directly heated gasifier. In contrast, the proposed process described here uses an indirectly heated gasifier. Two reactors are used: a gasification reactor in which the endothermic reactions occur and a combustion reactor in which the exothermic oxidation reactions occur. Fluidized bed material (typically a sand like material) in the reactors circulates between the gasifier and combustion reactors, carrying fixed carbon (char) from the gasifier to the combustor and heat from the combustor back to the gasifier. One advantage of this design is that the producer gas does not contain inert nitrogen since the gasification reaction occurs in the absence of air and, thus, has a higher heating value than the gas from a directly heated gasifier.

In Figure 1, wet biomass is dried in a Drier (S-1) by contact with air mixed with part of the hot exhaust stream of the Char Combustor (R-2). The biomass is dried to reduce moisture content to provide a consistent input to the gasifier. Dried biomass is contacted with steam and hot fluidized sand in the gasifier (R-1). The biomass reacts with steam and is converted into producer gas and fixed carbon in the form of a solid char. Fluidized sand and char from the gasifier flows to the Combustor where the char is burned with air to produce exhaust gas and heated sand. The hot fluidized sand flows back to the gasifier and provides energy for the endothermic gasification reactions.

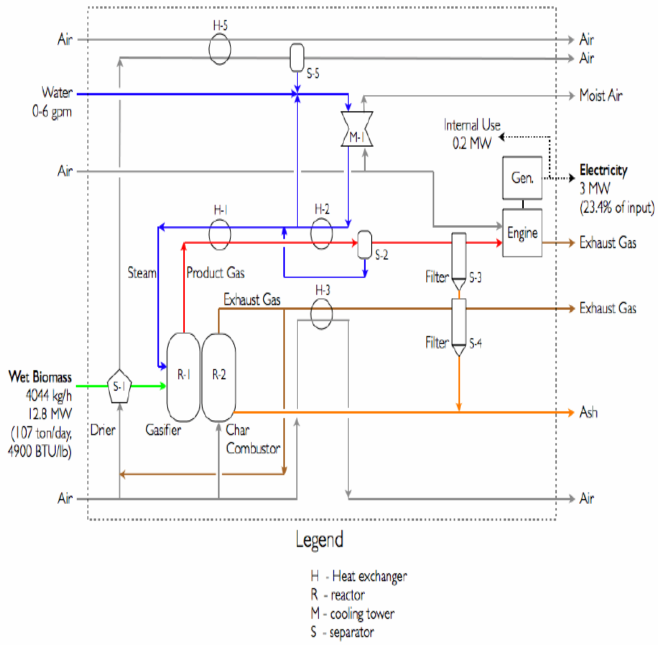

Figure 1: Biomass Gasification to Power Process

Product gas leaving the gasifier is cooled in heat exchangers H-1 and H-2. Water condensed from this gas is separated in flash drum S-2. The product gas is filtered in Filter S-3, and then fed to the engine-generator set. The product gas fed to the engine is composed of hydrogen, carbon monoxide, methane, and other hydrocarbons. A small portion of the electrical output of the generator is required for operation of plant equipment such as water pumps and air blowers. Not shown is optional equipment to capture waste heat from the engine exhaust. Exhaust gas leaving the char combustor is composed of nitrogen, oxygen, and carbon dioxide. The gas is split, with one fraction going to heat the air to the biomass drier and the other fraction cooled in heat exchanger H-3 and filtered by Filter S-4 before leaving the plant.

Steam fed to the gasifier is produced by heating water with the hot product gas in heat exchangers H-1 and H-2. Cooling water circulates through H-2 in a loop through an evaporative cooler (M-1). Water required to make steam for the gasifier is drawn from this loop and sent through heat exchanger H-2. Makeup water to replace this draw is obtained by condensing water from the exhaust air from the wet biomass drier in flash drum S-5. Any additional makeup water required is obtained as feed to the plant from the city mains.

Biomass Feedstock

Feedstock costs and availability represent some of the most critical aspects of any gasification project, with cost and contract considerations being the most important. The market for feedstock varies greatly depending on both the region and uses (current or expected) for the material being considered. This study focuses on using separated biomass feedstock from the Miramar Landfill in San Diego, CA and uses data associated with that site as the baseline for the analysis. Approximately 20% of the waste generated in the City of San Diego is organic waste, excluding organic waste classified as construction and demolition waste [1]. Of the residential waste in the Miramar Landfill, more than 14% of this is recyclable green material. Currently there is approximately 100,000 tons per year that is diverted to the Miramar Greenery in order to produce mulch, compost and wood chips that are available to the public. This is an important program designed in part to prolong the life of the landfill. The City of San Diego is planning on expanding the capacity of the Greenery to 150,000 tons/year in 2009.

With a fixed efficiency in the gasification process, the composition of the feedstock will directly impact the energy output per unit of biomass input. Feedstock quality can be measured in terms of the percentage of moisture, the percentage of ash, and the energy content, as measured by the higher heating value, of the biomass. Moisture is removed in the process and does not contribute to the energy output of the facility. Note that moisture is not expected to significantly impact the economics of the proposed plant since wetter biomass would likely cost less per ton; biomass is typically quoted in dollars per "bone dry ton". Therefore, the economic impact of more water in the biomass is more pre-processing, most significantly more land needed for drying biomass.

The baseline economic model assumed moisture at 30%, ash content at 5%, and a higher heating value of 7000 BTU per dry pound. Of these assumptions, the higher heating value was determined to be both the most uncontrollable during actual operation as well as the most significant economically. Therefore, the higher heating value was chosen as a probabilistic variable in our economic model simulations with a mean of 7,000 BTU/dry lb and the 99th percentile of the distribution of this value at 8,630 BTU/dry lb (see table 1). Biomass waste is increasingly becoming a commodity product.

Input	Mean	99%-tile	Model
Gasifier Capital Cost	$6,000,000	$7,395,800	Normal
Feedstock Higher Heating Value (HHV)	7,000BTU/dry lb	8,630 BTU/dry lb	Normal
Natural Gas Cost Facility Starts	$11.00/MMBTU	$12.80/MMBTU	Normal

Table 1: Probabilistic economic variables

The Miramar Landfill, as is typical of most landfills, currently sells wood chips, mulch and compost to landscapers and to the public. They also sell some of this wood waste material to electricity producers. Green waste recyclers including the greenery at the Miramar landfill have two sources of revenue. First a disposal fee of up to $25 per ton is collected [2] and secondly $18 per cubic yard ($90 per ton) is charged for the finished products that are sold [3]. The cost of processed green waste for use in a biomass gasification process to produce power is expected to be in the range of $15-$20 per ton

Capital Costs

The investment in equipment and facilities included in this feasibility analysis assumes constant output (3MW in the base analysis case) with operations 24/7 throughout the year with all installed hardware aimed for full utilization. It is further assumed that the biomass feedstock is pre-chipped and no chipping equipment is required. The capital costs for the gasification and gas cleanup equipment was estimated at $6M and the cost of and engine generator set to be $750/kW The total facility capital costs for a 3 MW system is $8,275,000. Note that in the analysis, including capturing waste heat for export, an additional $150/kW was added for heat recovery equipment. Accounting for parasitic load, this translates to a cost of $2,849/kW.

Operating Costs

Figure 2 shows the breakdown of operating expenses associated with a 3MW facility, excluding feedstock costs. All expenses were assumed to escalate at a general inflation rate of 2.1% per annum.

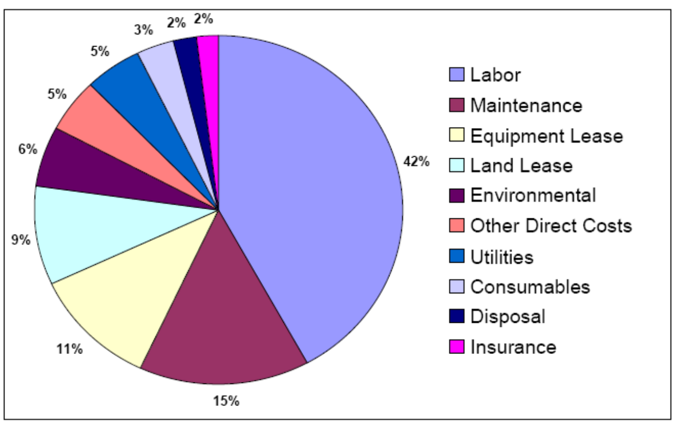

Figure 2: Operating Costs (excluding feedstock costs)

Production Credits/Incentives

The federal government has long standing incentives supporting renewable energy, starting initially with the passage of the Public Utility Regulatory Policies Act (PURPA) in 1978. PURPA provided a series of incentives to "qualifying facilities" which includes cogeneration facilities and small power production facilities that use biomass, waste, or renewable resources (including wind, solar, and water) [4]. Note that the proposed biomass to power project on the Miramar landfill would likely be able to obtain qualifying facility designation. At the time of its passage, one of PURPA's important provisions required utilities selling retail power to purchase from the small, independent qualifying facilities at the utility's avoided cost rate to procure or produce the power from other sources. The project under consideration for the Miramar landfill, an open-loop biomass facility using cellulosic waste, qualifies for production tax credits of $0.01/KWh for a period of 5 years from the date the facility is placed in service [5].

Feed in Tariff

A Feed in Tariff is an incentive structure to encourage the adoption of renewable energy through government legislation [6]. In order to meet the California Renewable Portfolio Standard (RPS) created under SB 1078 and accelerated under SB 107, Investor Owned Utilities (IOU) are required to purchase or generate 20% of their electricity from renewable sources by 2010. Of this amount, an executive order of the Governor has mandated that 20% come from biomass to electricity projects [7]. In order to do so, utilities have established Feed in Tariffs and standard contracts to help expedite the deployment of renewable projects. Southern California Edison (SCE) has one such program for biomass projects ranging in size from less than 1 MW up to 20 MW [8]. Standard contracts incorporate Time of Day (TOD) pricing along with the assignment of all green attributes, such as RECs and carbon credits, to SCE. For example plants that chose a 20 year contract with an on-line year of 2010 the standard contract rate is $98.40/MWh. Southern California Edison provides a feed-in tariff rate based upon contract initiation date and production rate. Due to the current market uncertainty for Renewable Energy Credits (REC) and Carbon Credits, contracting for a Feed in Tariff represents the lowest risk revenue source for the proposed Miramar biomass to power facility.

Financial Analysis of Alternative Location Scenarios

Three potential location scenarios were analyzed for economic feasibility: (1) the primarily location was the Miramar Landfill, (2) adjacent to the landfill on the Marine Corp Air Station (MCAS) Miramar with feedstock transported from the landfill and (3) a "generic" site with optimized parameters to obtain a positive net present value (NPV). The financial analysis was conducted with an Excel™-based economic model developed by expanding upon a simple model available from The California Biomass Collaborative [9].

<u>Significant Inputs:</u> With respect to revenue potential, power sales were assumed at the feed-in rate set for small biomass facilities, or in the case of MCAS Miramar, at the incremental cost of power for the retail customer. As previously discussed, capturing revenue associated with environmental attributes from items such as carbon credits represent some degree of risk. Therefore, such revenue was not considered in any of the cases. It is contractually relinquished in the cases where a feed-in tariff is assumed. Lastly with regard to revenue, waste heat sales are assumed to be zero for all three cases, although it is feasible a customer for the waste heat could be located at a future site.

Financial assumptions included using a cost of equity of 20%, a cost of debt of 5%, and 50% leverage, except in the 3rd "generic" case where leverage was increased to 65%. Sensitivities were subsequently conducted on both the cost of debt and the leverage. Of considerable economic value, biomass facilities that receive "qualifying facility" status under the Public Utility Regulatory Policy Act (PURPA) may use 5-year accelerated (MACRS) depreciation. This incentive was included in all scenarios considered. A simple construction period model of 9 months was used in all cases wherein all capital investment was assumed to occur at time zero with revenues and most expenses initiating 9 months later. Certain fixed costs such as land lease, insurance, and utilities as well as 49% of the labor cost (including plant management, lead operator/maintenance, and administrative assistance) commenced at the time of capital investment.

The balance of the operating costs, significantly feedstock costs and the remaining labor costs, begin upon start-up of the facility after the 9 month construction phase. It is likely that this construction period assumption is conservative depending on how such a project is actually financed and conducted. Other financial assumptions include a 20-year project life without any additional capital investment. Consequently, no value associated with cash flows continuing in perpetuity was included. An inflation rate of 2.1% was applied to operating expenses, including feedstock. This same inflation rate was applied to escalate the production tax credit since current law allows for such inflation escalation. While not used in the three scenarios analyzed, heat sales also escalated at this inflation rate in the sensitivity analyses employed to analyze the scenarios.

Another input included assuming an on-stream rate of 93% (with a sensitivity analysis conducted on lower on-stream rates). Finally, note that the three scenarios analyzed a 3 MW plant, although capital and certain operating costs were scaled to 5MW in a plant sizing sensitivity analysis. In addition to the inputs discussed above, certain inputs were modeled as probabilistic variables feeding Monte Carlo simulations for the first two scenarios analyzed. The inputs modeled as varying over a normal distribution are summarized in Table 1.

Scenario 1: Miramar Landfill

The initial site location to be considered for the a 3 MW gasification power plant was the Miramar landfill in San Diego, California. Among other reasons, Miramar was chosen for this feasibility study since diversion of green waste to the gasifier could extend the life of the landfill. Initially, the landfill was believed to be scheduled to close in December 2011 [10]. Extending the life of the landfill has economic value to the city since, upon closure of the landfill, waste will need to be diverted to other landfills, adding to transportation costs. One of the challenges to the feasibility of the proposed project is that the City of San Diego has alternatives available to it to extend the life of the landfill. One alternative that has been successfully pursued is to increase the capacity of the landfill. The City of San Diego received in March of 2008 approval from the California Integrated Waste Management Board for several changes to the Miramar landfill Solid Waste Facility and Site Development Permits. Amongst other changes, this allowed for a 20 foot increase in the maximum height of the landfill to a maximum elevation to 485 feet above mean sea level, resulting in an increase of 12,550,000 cubic yards from the current permitted capacity. This will delay the closure date of the landfill until 2017 [11] and delays the time at which the landfill will transition into a material recycle facility where on site process of material has an additional economic benefit associated with not having to ship the green waste and other materials to distance landfills.
The consequence of having extending the landfill life is that the city is not inclined to share any benefits associated with a longer life of the landfill. Closure of the landfill is not imminent and multiple opportunities exist for the city not only to extend the life of the landfill, but also increase revenues associated with the green waste it handles.

There are additional disincentives beyond the inability to capture economic rents associated with extending the life of the landfill and the anticipated high price of feedstock. As described above, the landfill continues to pursue a strategy of seeking higher height allowances enabling a greater capacity. Due to height restrictions imposed by the Miramar Marine Core Airs Station (MCAS) this strategy competes directly with the project concept of locating a 40 foot tall gasifier on the landfill. Another disincentive for siting the gasifier on the Miramar landfill is the lack of a clear source of waste heat revenue. Thermophilic composting may be of value when the Miramar landfill does close allowing for a reduction in weight of material moving through Miramar as a transfer station.

As indicated there are significant non-economic factors weighing unfavorably on a proposed project being sited at the Miramar landfill including very short term contracts on feedstock and height restrictions. Additionally, there are several economic factors making the project appear less viable including high feedstock costs and the lack of a waste heat revenue stream. Nevertheless, given these challenging economic inputs, a financial model was constructed using appropriate inputs for the Miramar landfill site.

<u>Miramar Landfill site -Assumptions and Inputs:</u>

1. Feedstock cost is assumed to be $15/short ton
2. Land lease cost is assumed to be $100,000 per year
3. Electricity sales at Southern California Edison feed-in rate, foregoing revenue associated with REC's and other environmental offsets.
4. No opportunity for waste heat revenue

The levelized annual cost (LAC) results from the Monte Carlo simulation for the Miramar landfill scenario are shown in fig. 3 showing the expect mean cost of power production on a levelized annual cost. (LAC). With a mean LAC at $119.2/MWh, predicts that there is essentially no chance that the LAC of the power produced at the site will be less than $107.4/MWh. This is an unfeasible cost structure in the case that the power sales are to occur at the feed-in rate of $98.4/MWh. An alternative evaluation, coming to the same conclusion regarding the infeasibility of the project, is that at a power sales price of $98.4/MWh, the net present value (NPV) for the project, under the inputs outlined above, is -$2.7 million. Putting aside the inability to site on the Miramar landfill, economically a project would have a 50% chance of meeting desired returns on capital if sales could be made to a retail customer willing to pay greater than $119.2/MWh plus any wheeling charges associated with transmitting and selling power to this retail customer.

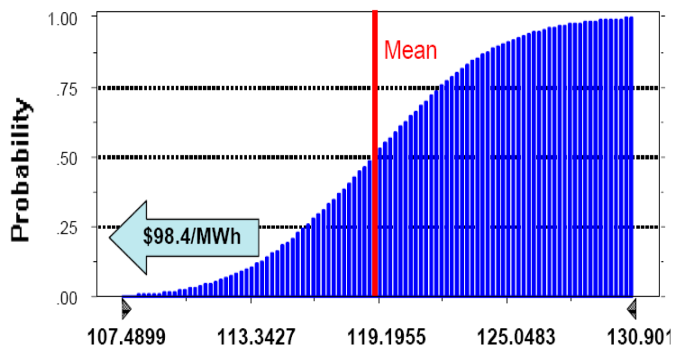

Figure 3: Cumulative probability of levelized annual cost for Miramar Landfill

Scenario 2: MCAS Miramar

In addition to the base case of siting the gasifier on the Miramar landfill, a related case was explored. In this case, a gasifier to power project was located on the MCAS Miramar with feedstock supplied from the Miramar landfill. This option was initially explored to overcome the height restriction in place at the landfill as well as the potential for a waste heat customer. However, MCAS Miramar has no need for waste heat. To be conservative, this case was modeled without waste heat although future energy conservation needs may make waste sales possible in the future. An additional opportunity with siting the project on the air station is for higher contract terms on the power generated since this power now replaces other potentially higher cost sources of power, such as purchasing power off the grid. While enhancing the economics versus a project directly on the landfill, the feedstock costs were modeled to be equal to the landfill green waste price plus additional transportation costs to move the feedstock to the MCAS. While the potential exists to bypass Miramar landfill green waste, perhaps contracting directly with green waste collectors, doing so would require additional land area on the air station for feedstock preparation (chipping and drying), land that may not available. Finally, the power rate modeled represents the air station's incremental cost of power. Therefore, the project would likely be able to retain any green attributes for which the project might qualify. This represents a possible additional source of revenue, albeit uncertain, which was not included in our analyses.

<u>MCAS Miramar Case - Assumptions and Inputs:</u>
1. Feedstock cost is assumed to be $20/short ton (Miramar input costs + transportation costs) Land lease costs is assumed to be $50,000 per year.
2. Electricity sold at $0.10 per kW-hr ($100/MWh), the MCAS next best alternative for incremental power.
3. No opportunity for waste heat revenue

The levelized annual cost (LAC) results from the Monte Carlo simulation for the MCAS Miramar scenario are shown in the fiigure 4, with a mean LAC of $124.6/MWh. This analysis predicts that there is essentially no chance that the LAC of the power produced at the site will be less than $111.7/MWh. The cost structure in the case is also greater than the power sales that could occur at the MCAS incremental cost of $100.0/MWh. An alternative evaluation, coming to the same conclusion regarding the infeasibility of the project, is that with a power sales price of $100.0/MWh, the net present value (NPV) for the project, under the inputs outlined above, is -$2.8 million. In comparison to the primary scenario at the Miramar Landfill, the slightly higher power price is more than offset by the increase in feedstock/transportation costs.

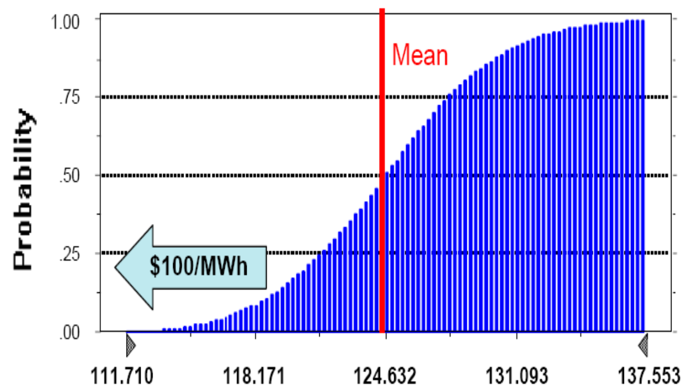

Figure 4: Cumulative probability of levelized annual cost for MCAS Miramar.

Scenario 3: Optimized "Generic" Site

Further extending the considered business analysis an optimize "Generic" was postulated. In this case, feed-in tariff rates available in California from utilities such as Southern California Edison were again used for the calculation of power revenue. Differing from the other scenarios, this case assumed much more favorable prices and terms in contracting for feedstock. Whether achieved through contracting with multiple green waste generators, such as landscaping companies, or through a single large generator, it was assumed that a reliable supply of feedstock could be achieved at prices much lower than being offered by the Miramar landfill.

<u>Optimized "Generic" Site - Assumptions and Inputs.</u>
1. Feedstock cost is assumed to be $2/short ton
2. Land lease costs is assumed to be $30,000 per year
3. Electricity sales at Southern California Edison feed-in rate, foregoing revenue associated with REC's and other environmental offsets.
4. No waste heat revenue
5. Leverage increased to 65%

By increasing the leverage in this "generic" case to 65%, yielding a weighted average cost of capital (WACC) of 9%, a positive NPV project was generated for this hypothetical case selling at the feed-in tariff rate of $98.4/MWh. Figure 5 illustrates the components of the NPV of the project. Of significance, the tax incentives in the form of production tax credits and accelerated depreciation are needed to create an

NPV positive project. Note that an NPV positive project could also be developed at the baseline 50% leverage with either a larger plant or some waste heat sales.

Initial Investment	($8,725,000)
EBITDA	$8,776,424
Taxes on EBITDA	($3,540,059)
Production Tax Credit	$910,005
Depreciation Tax Shield	$2,619,301
Working Capital Additions	$0
NPV	$40,671

Figure 5. Net Present Value (NPV) for Optimized Parameters

Sensitivity Analysis

The sensitivity of the "generic" project's NPV, with $2/ton feedstock and 50% leverage, was tested against several input parameters. A 3MW facility generates approximately 4,900KW of heat. This heat can be utilized when the plant has heat recovery equipment. This equipment is estimated to cost $150/KW of electrical capacity, so recovering heat on a 3MW facility requires an additional investment of $150 x 3000 KW = $450,000. Figure 6 shows the NPV of the project at various power prices and waste heat prices. As shown in the figure, the additional revenue potential more than pays for the additional capital costs with the opportunity to significantly enhance the project returns. At baseline assumptions, a minimum waste heat price of $1.5/MMBtu would yield a feasible project. Note that the current cost of natural gas is over $12.00/MMBtu. At the feed-in rate of $98.4/MWh, the project NPV would be approximately $2 million if the captured waste heat was sold at $4.50/million BTU. Higher prices for waste heat would lead to even greater returns.

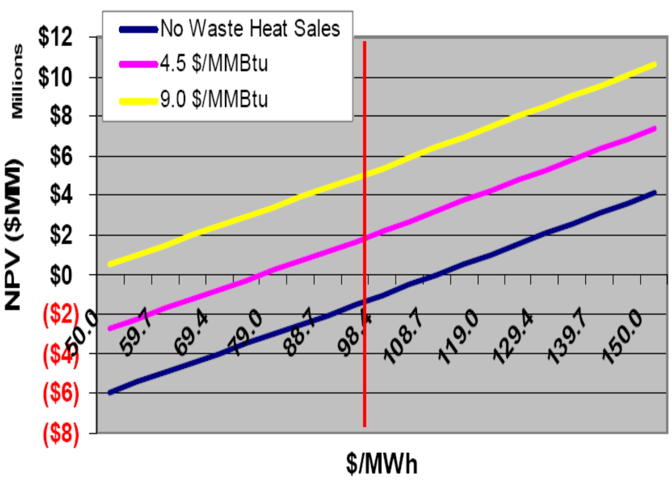

Figure 6. Sensitivity of project returns to power prices and waste heat prices.

In summary, the ability to sell waste heat at $4.5/MMBtu is worth essentially $0.03/KWh, demonstrating the waste heat revenue potential as being one of the more sensitive parameters impacting the project returns. Note that waste heat revenues were assumed to escalate with inflation. If a site can be found that combines availability of feedstock with a host heat customer, the project could provide attractive returns.

Additionally, the project returns were quite sensitive to plant sizing. In order to model the impact of returns on plant size, the capital investment and some of the operating expenses were scaled up from the 3MW facility. The gasifier capital cost was scaled by the square root of the ratio of the capacity; a 5MW gasifier was estimated to cost $6 million x $(5MW/3MW)^{1/2}$ = $7.746 million. The engine/generator sets were scaled linearly (at $750/KW). A larger plant, which was assumed to have the same efficiencies as a 3MW facility, will require more feedstock in direct proportion to the power output of the plant. Some operating costs were scaled linearly including maintenance, consumables and utilities. Significantly, the largest operating cost, labor, was left the same for a 5MW plant under that assumption that the same manpower required for a 3MW facility could operate the larger plant.

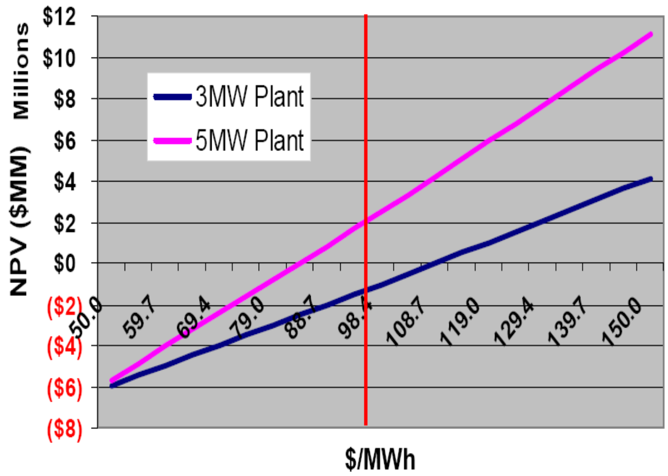

Figure 7. Sensitivity of project returns to power prices and plant size

In Figure 7 the NPV for a 5MW plant at different power prices is compared to a 3MW plant. Note that approximately $2 million of NPV is generated by a 5MW facility at the feed-in tariff price of $98.4/MWh. It was found that at breakeven ($0 NPV), moving from 3MW to 5MW is worth approximately $0.025/KWh.

Sensitivity analysis on the NPV was also conducted on power sales rates and feedstock costs. As would be expected, at a given power sales price project returns degrade with increasing feedstock costs as shown in Fig. 8. Note that negative feedstock cost, in the form of tipping fees to accept green waste, is not beyond possibility and would improve project returns.

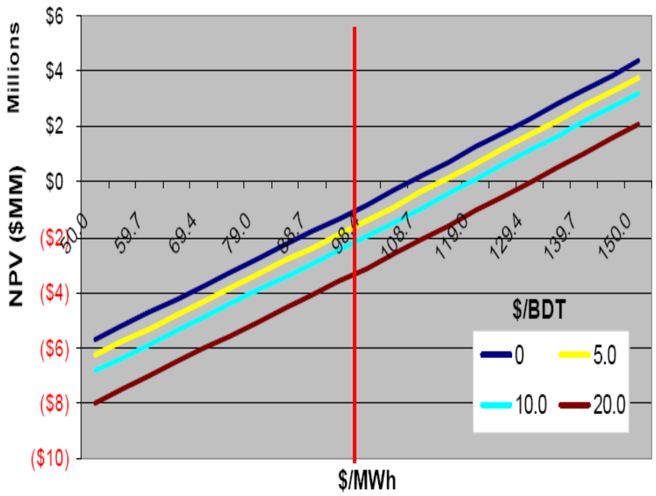

Figure 8. Sensitivity of project returns to power prices and feedstock costs

Figure 9 shows the impact of decreasing on-stream rates below the aggressive baseline of 93%. This illustrates that significant operational risk exist. Note that this analysis assumes downtime at an average power sale price as shown on the x-axis. The contractual feed-in tariff, however, varies significantly by time of day and season, with prices during peak summer hours over 3 times the average price while off-peak sales are lower than 0.7 times the average. Therefore, the time of day and season when downtime occurs will also impact project returns.

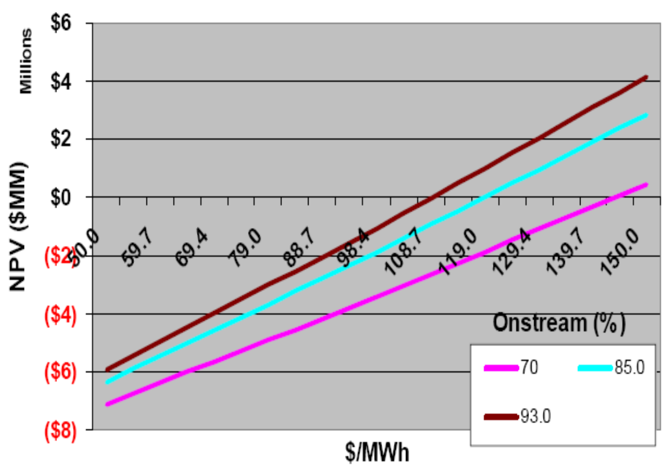

Figure 9. Sensitivity of project returns to power prices and on-stream rate.

A financing sensitivity was performed exploring the impact of leverage and debt cost. In Figure 10 the results demonstrate increasing NPV with increasing leverage as a result of the lower cost and tax advantages of debt financing. It is not atypical for power projects of this type to utilize a high degree of leverage, well above the baseline case of 50% modeled. As the figure indicates, the project returns are relatively more sensitive to leverage than to debt cost.

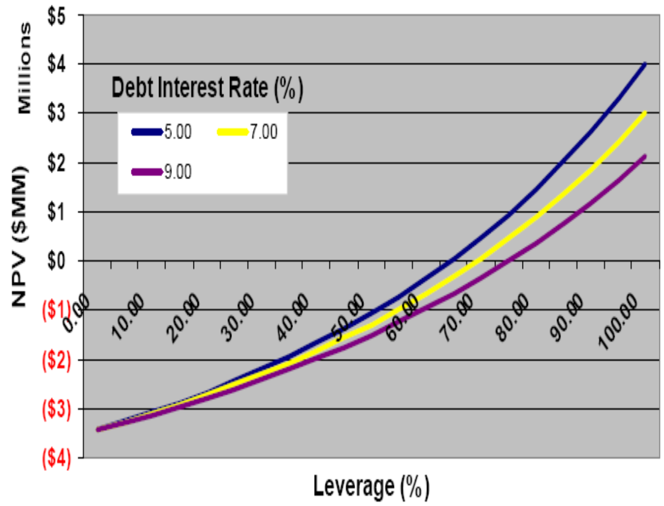

Figure 10. Sensitivity of project returns to financial leverage and debt interest rate

Conclusions and Recommendations

Based on height restrictions and other factors, it appears unlikely that a biomass gasification power plant could be located on the Miramar landfill. Furthermore, establishing long-term, cost effective feedstock supply from the landfill appears difficult. Lastly, there are no evident opportunities for waste heat revenue for a plant located on the landfill.

For these reasons, locating a biomass power plant on the Miramar landfill is not deemed feasible. Even when putting aside some of these factors, without the prospect of waste heat revenue, the project would need power revenue at over $119/MWh, well over feed-in tariffs and the incremental cost of power for most industrial or institutional users. There is, however, the possibility that a customer would be willing to pay a premium price for the renewable power.

The project returns, however, are much more sensitive to the generation of waste heat revenue. As such, locating a waste heat customer in close proximity to the proposed biomass plant would be one of the more effective steps that could be taken to meet desired returns for the project. The project returns were also quite sensitive to plant size. If the emissions performance of the gasification technology allowed the plant to scale to 5MW, as modeled, the plant would be more economically viable.

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