Biomass Feasibility Analysis
REPORT

Prepared for

ENERGY KEEPERS, INC.

Confederated Salish and Kootenai Tribes

Polson, Montana

HARRIS GROUP

Report 30496.00/01

February 12, 2015

Harris Group

300 Elliott Ave W
Suite 500
Seattle, WA 98119
(206) 494-9400
www.harrisgroup.com

February 12, 2015

Mr. Angelo Muzzin
Energy Keepers, Inc.
110 Main Street, Suite 304
Polson, MT 59860

Reference: Energy Keepers, Inc.
Biomass Feasibility Analysis
Final Report
Harris Group Project No. 30496.00

Mr. Muzzin:

Presented herein is the final report of our review and analysis of the technical, economic, and contractual feasibility of co-generation biomass power production and fuel supply options on the Flathead Reservation. Energy Keepers, Inc. (EKI), a corporation of the Confederated Salish and Kootenai Tribes (CSKT), focused on energy asset development, operations, and marketing for the CSKT commissioned this analysis through a grant awarded by the U.S. Department of Energy.

Several co-generation options were evaluated, each operating on biomass fuels available from Tribal and U.S. Forest Service (USFS) lands. Our report reviews the accessibility and cost of fuels, analyzes current Tribal energy use, evaluates process and engineering options, analyzes economic returns of the options and sets forth our conclusions regarding the same.

We wish to express our sincere appreciation for the cooperation and assistance provided by representatives of EKI and CSKT.

Respectfully submitted,

HARRIS GROUP

BIOMASS FEASIBILITY ANALYSIS

Table of Contents

SECTION 1 – EXECUTIVE SUMMARY 1

SECTION 2 – SCOPE OF STUDY 7

SECTION 3 – DESCRIPTION OF PRELIMINARY PROCESS DESIGN/TECHNOLOGY SELECTION 10

SECTION 4 – FUEL SUPPLY AND ASSOCIATED ECONOMIC ANALYSIS 15

SECTION 5 – TRIBAL BUILDINGS ENERGY USAGE ASSESSMENT 29

SECTION 6 – SITE ASSESSMENT 33

SECTION 7 – CAPITAL COST ESTIMATES 38

SECTION 8 – LONG-TERM OPERATING AND MAINTENANCE PLANS 44

SECTION 9 – ECONOMIC ANALYSIS OF PROJECT OPTIONS 51

SECTION 1 – EXECUTIVE SUMMARY

PROJECT OVERVIEW

Energy Keepers, Inc. (EKI), a corporation of the Confederated Salish and Kootenai Tribes (CSKT), focused on energy asset development, operations, and marketing for the CSKT, commissioned this co-generation biomass power production and fuel supply feasibility study (the Study) through a grant awarded by the U.S. Department of Energy (DOE). Several co-generation options were evaluated, each operating on biomass fuels available from Tribal and U.S. Forest Service (USFS) lands.

EKI directed Harris Group to perform this Study to determine the technical, economic, and contractual feasibility of co-generation biomass power production and fuel supply options on the Reservation. Harris Group initially evaluated two options as part of the requested feasibility study:

> Option 1 focused on the use of fuels exclusively from CSKT lands that would be used to fuel a 3.5-megawatt (MW) cogeneration facility to service the needs of the CSKT complex located in Pablo, Montana.
>
> Option 2 focused on fuels from CSKT lands and adjacent USFS lands that would be used to fuel a larger, 20 MW cogeneration facility to service the needs of the CSKT complex and to provide for substantial electrical sales off the Reservation or to the local utility, Mission Valley Power.

Our report reviews the accessibility and cost of fuels, analyzes current Tribal energy use, evaluates process and engineering options, analyzes economic returns of the options, and sets forth our conclusions.

OBSERVATIONS AND CONCLUSIONS

Principal observations and conclusions that we have reached during our development of the Study are set forth below. This report should be read in its entirety for a complete understanding of the estimates, assumptions, and analyses upon which these opinions are based.

SECTION 2 – SCOPE OF STUDY

1. The scope of work was adjusted after both the 30% and 60% design review meetings.

2. The scope of the 30% review effort included evaluation of the fuels supply available from the CSKT and USFS lands, evaluation of the local building energy needs, development of preliminary plant technical information, preliminary site evaluation, and economic evaluation of the proposed steam/condensate distribution lines.

3. The economic evaluation of the proposed steam/condensate distribution lines identified that the cost for the 1.5-mile pipelines, combined with the cost to convert

the existing heat-pump-based heating systems to the use of thermal energy, could not be justified by the potential savings. Therefore, the scope of work was adjusted to eliminate steam distribution.

4. The scope of the 60% review effort included: obtainment of budgetary pricing for major equipment associated with the 20 MW facility, evaluation of the Plum Creek Timber site infrastructure, finalization of the fuels supply pricing and availability from the CSKT and USFS lands, development of preliminary plant technical information, evaluation of the existing electrical substation, and evaluation of environmental permitting requirements.

5. After the 60% review meeting, EKI paused the study effort while it evaluated options for the project path forward. Based on this evaluation, EKI adjusted the scope of the third phase of work to include:

    a) Evaluation of the 20 MW facility, based on condensing the steam produced and exporting all of the electricity.

    b) Evaluation of the 5 MW facility, based on condensing the steam produced and exporting all of the electricity.

    c) Evaluation of a third configuration, with a 5 MW facility having a steam host that would offset the cost of fuel by 50%.

    d) Development of budgetary, rough order-of-magnitude (ROM), factored, capital cost estimates for the three configurations, based on major equipment pricing received plus Harris Group historical pricing for the balance of equipment.

    e) Development of the operations and maintenance (O&M) scope of the study only to the extent necessary to support a budgetary O&M cost for the pro forma based on Harris Group historical data.

    f) Development of a budgetary financing analysis with a breakeven analysis for the three configurations, incorporating the capital cost, O&M costs, and the predicted power sales prices developed by EKI.

    g) Development of a project report reflecting the work performed and the results of the Study.

SECTION 3 – DESCRIPTION OF PRELIMINARY PROCESS DESIGN/TECHNOLOGY SELECTION

1. Initially, the Study was focused on two co-generation options, a 3.5 MW (net output) facility and a 20 MW (gross output) facility; however, after preliminary development work and analysis, the focus was changed to three options:

    a) 20 MW (net output) without co-generation

b) 5 MW (gross output) without co-generation

c) 5 MW (gross output) with cogeneration, commonly referred to as combined heat and power (CHP)

2. The Study focus was changed to include two options without co-generation after the preliminary economic evaluation of the cost of distributing steam from the co-generation facilities to the local Tribal, college, and high school buildings proved to be uneconomical. The installation costs for steam and hot water piping distribution systems were estimated at $3.8 MM and $2.5 MM, respectively.

3. Based on a technology study, a stoker-fired packaged tube boiler was selected as the combustion technology for the 5 MW system; while a field-erected bubble bed boiler was selected for the 20 MW system.

4. Due to limited wastewater treatment and discharge capacity from the Plum Creek Timber site, a wet surface air-cooled condenser (WSACC) was selected as the preferred heat rejection technology. The design of the WSACC prevents evaporation of the cooling water on the heat exchanger surface, so it is capable of using water with considerably more dissolved solids. This capability reduces the blow-down frequency of the system, consequently reducing the volume of wastewater produced.

5. Our analysis assumes that the existing Plum Creek Timber transformer will remain in place and be reused for the 5 MW options, while a new transformer will be required for the 20 MW option.

SECTION 4 – FUEL SUPPLY AND ASSOCIATED ECONOMIC ANALYSIS

1. The biomass fuel supply was evaluated based on two options:

a) Biomass fuels collected from Tribal lands only – CSKT Scenario

b) Biomass fuels collected from Tribal and USFS lands and other sources – 40-Mile Scenario

2. The recoverable biomass fuel available within the CSKT Scenario was estimated to be 47,700 bone dry tons (BDT) per year.

3. The recoverable biomass fuel available within the 40-Mile Scenario was estimated to be 363,400 BDT per year.

4. The overall average delivered fuel cost within the CSKT Scenario was estimated to be $50.37/BDT.

5. The overall average delivered fuel cost within the 40-Mile Scenario was estimated to be $55.11/BDT.

6. A fuel supply cost estimator spreadsheet has been developed and provided as part of this Study.

7. Prior biomass studies were evaluated during the preparation of this Study, with all of them finding significant volumes of biomass fuel to be available from a variety of sources. However, the volume available from each source is largely dependent on the level of economic activity occurring within the forest products industry.

SECTION 5 – TRIBAL BUILDINGS ENERGY USAGE ASSESSMENT

1. Based on inspections of Tribal government buildings, college buildings, and the high school, it was determined that three types of fuels are used to provide heat:

   a) Electricity
      I. Element heaters
      II. Air source heat pumps
      III. Water source heat pump
   b) Oil – burned to heat air or water
   c) Propane – burned to heat air

2. Calculations were completed to determine the annual heating load of the selected buildings. This load was estimated to be 17,096,850 kBTU/year

3. Based on the completed energy analysis, it was determined that the installation of a steam supply and distribution system has insufficient payback to justify the capital investment.

SECTION 6 – SITE ASSESSMENT

1. The former Plum Creek Timber sawmill in Pablo was identified as the primary site for a proposed co-generation biomass power production facility. The SKC campus was initially evaluated as a possible location; however, it was quickly realized that, due to the limited acreage combined with the significant increase in truck traffic around the campus, it would not be a viable site option.

2. Water is available via multiple on-site wells. However, in order to access the city sewer, customers are required to have a water meter installed and purchase water from the district. The off-site connection to the water system and the sewer is within a reasonable distance to the southeast of the site.

3. Electricity is available on-site via an existing substation with transformers. This has been identified as the interconnection point for the plant auxiliary power as well as the export power. These transformers are owned by Valley Electric, the local utility. The facility cost estimates include allowances for upgrades to the substation to accommodate the import and export of power.

4. Air permitting requirements were evaluated for both the 5 MW and 20 MW facilities.

    a) The 5 MW facility qualifies for advantages in the permitting process due to the lower levels of emissions. Our research indicates that it would be categorized as a "synthetic minor" source, based upon a potential equipment vendor's emission estimates. "Synthetic minor" sources are those with federally enforceable limits on a source's emissions or operating conditions that keep emissions below a major source threshold emission rate.

    b) The ultimate classification of the 20 MW facility as a major or minor source will depend on additional analysis of the fuel sources. Chloride and mercury concentrations in fuel will determine if potential emissions exceed regulatory thresholds for HCl and mercury.

SECTION 7 – CAPITAL COST ESTIMATES

1. The conceptual level capital cost estimate applicable to both 5 MW options (condensing and CHP) was determined to be $37,649,334.

2. The conceptual level capital cost estimate applicable to the 20 MW option was determined to be $117,989,914.

SECTION 8 – LONG-TERM OPERATING AND MAINTENANCE PLANS

1. The fuel cost associated with the 20 MW 40-mile Scenario was estimated to be $47.37/BDT.

2. The annual operating and maintenance costs associated with the 20 MW facility were estimated to be $14,101,716, with non-fuel operating costs estimated at $6,877,000 and labor costs estimated at $2,480,050. This results in a non-fuel O&M cost of $43.60/MWh.

3. The fuel cost associated with the 5 MW CSKT Scenario, *CHP* facility was estimated to be $19.79/BDT. The low cost of fuel in this option is due to the assumption that an on-site sawmill is supplying 50% of the fuel at no cost.

4. The annual operating and maintenance costs associated with the 5 MW *CHP* facility were estimated to be $4,372,252, with non-fuel operating costs estimated at $3,430,376 and labor costs estimated at $1,682,376. This results in a non-fuel O&M cost of $102.22/MWh.

5. The fuel cost associated with the 5 MW CSKT Scenario, *condensing* facility was estimated to be $48.63/BDT.

6. The annual operating and maintenance costs associated with the 5 MW *condensing* facility were estimated to be $5,508,703, with non-fuel operating costs estimated at

$3,424,376 and labor costs estimated at $1,682,376. This results in a non-fuel O&M cost of $102.22/MWh.

SECTION 9 – ECONOMIC OPTIONS OF PROJECT OPTIONS

1. A full year of energy output from the 20 MW facility was estimated to be 157,680 MWh.

2. The average power revenue over the 20-year life of the 20 MW facility was estimated to be $63.65/MWh.

3. The financial model projects that the revenues associated with 20 MW facility are insufficient to cover the operating costs of the facility and will not provide a return on the investment.

4. The 20 MW facility IROR breakeven point was estimated to be $136/MWh. The negative cash flows calculated indicate that this option does not generate enough cash to cover the basic operating expenses, which are dominated by the fuel cost.

5. A full year of energy output from the 5 MW facilities was estimated to be 33,507 MWh.

6. The average power revenue over the 20-year life of each of the 5 MW facilities was estimated to be $68.05/MWh.

7. The financial model projects the revenues associated with the 5 MW facilities are insufficient to cover the operating costs and will not provide a return on the investment.

8. The 5 MW, condensing, facility IROR breakeven point was estimated to be $245/MWh. The negative cash flows calculated indicate that this option does not generate enough cash to cover the basic operating expenses which are dominated by the fuel cost.

9. The 5 MW CHP facility IROR breakeven point was estimated to be $208/MWh. The negative cash flows calculated indicate that this option does not generate enough cash to cover the basic operating expenses, which are dominated by the fuel cost.

SECTION 2 – SCOPE OF STUDY

2.1 GENERAL SCOPE

EKI directed Harris Group to perform a study determining the technical, economic, and contractual feasibility of co-generation biomass power production and fuel supply options on the Reservation. Harris Group initially evaluated two options as part of the requested feasibility study:

Option 1 focused on the use of fuels exclusively from CSKT lands that would be used to fuel a 3.5-megawatt (MW) cogeneration facility, to service the needs of the CSKT complex located in Pablo, Montana.

Option 2 focused on fuels from CSKT lands and adjacent USFS lands that would be used to fuel a larger, 20 MW cogeneration facility to service the needs of the CSKT complex and to provide for substantial electrical sales off the Reservation or to the local utility, Mission Valley Power.

EKI requested that the Study incorporate an assessment of the availability and accessibility of biomass fuels on the Reservation, review the physical characteristics, determine the viability of the proposed site, and analyze the CSKT's current energy consumption, commercial markets, utility interconnection, and transmission options to allow for the sale of surplus electrical power. In addition, the Study considered environmental issues and provided an economic analysis of each option.

This feasibility analysis was developed not only to evaluate these options for offsetting electrical costs but also to evaluate different business opportunities resulting in creation of jobs on or near the CSKT Tribal lands. The original scope of work was adjusted after both the 30% and 60% design review meetings, based on the work completed to date.

2.2 30% REVIEW SCOPE

The first phase of work involved developing preliminary information to support a 30% design review with EKI. The scope of the 30% review effort included:

2.2.1 Evaluation of the fuels supply available from the CSKT lands to support the 3.5 MW bio-mass co-generation facilities. This included the annual available fuel supply and the delivery cost over the entire forecast period.

2.2.2 Evaluation of the fuels supply available from the CSKT lands and USFS lands within a 40-mile radius of Pablo to support the 20 MW biomass co-generation facilities. This included quantity, ranges, confidence levels, and costs associated with the current long-term delivery of the fuel supply from the combined lands and other land holdings that might be available.

2.2.3 Evaluation of the current energy needs of the Tribal government, college, and high school buildings (CSKT Facilities) and forecast future energy usage. This included an assessment of alternate methods of energy use in the CSKT Facilities, including steam generated from the planned bio-mass co-generation facility.

2.2.4 Development of preliminary plant configuration, technology selection, and heat balances to support the bio-mass co-generation plant, as well as provision of steam to the CSKT Facilities.

2.2.5 Completion of a preliminary site evaluation for the biomass co-generation facility, including the evaluation of a steam/condensate line to support providing steam to the CSKT Facilities, as well as the balance of plant equipment and utilities required to support the biomass co-generation facility.

2.3 60% REVIEW SCOPE

The second phase of the work, as originally envisioned, involved building on the previous efforts to advance the design to the 60% completion level in preparation for a review meeting with EKI personnel. However, the preliminary economic information presented at the 30% review meeting caused EKI to pause the Study work while design options were evaluated. Subsequently, the Study effort was re-started; however, the focus was now directed to the 20 MW biomass co-generation option, without steam supply to the CSKT facilities, and the further evaluation of the suitability of the Plum Creek site.

The development of the 60% design included the following tasks:

2.3.1 Obtaining budgetary pricing for primary equipment associated with the 20 MW plant, i.e., boiler island, steam turbine, heat rejection systems, etc.

2.3.2 Evaluating the infrastructure benefits of the Plum Creek site.

2.3.3 Updating the fuel supply pricing and finalizing the fuel supply report for review at 60%.

2.3.4 Developing the 20 MW plant site arrangement drawings based on the Plum Creek site, including evaporation pond requirements.

2.3.5 Developing the facility heat balance and equipment list to support the capital cost estimate.

2.3.6 Continuing discussions with the local utility associated with the use of the existing substation on the Plum Creek site and development of electrical one-line diagrams to support the capital cost estimate.

2.3.7 Continuing the evaluation of the permitting requirements associated with locating the biomass co-generation facility on the Plum Creek site.

2.4 FINAL REVIEW SCOPE

After the 60% review meeting, EKI paused the study effort while it evaluated options for the project path forward. Based on this evaluation, EKI adjusted the scope of the third phase of work to include the following tasks:

2.4.1 Evaluating the 20 MW facility, based on exporting all of the electricity produced.

2.4.2 Evaluating the 5 MW facility, based on exporting all of the electricity produced.

2.4.3 Evaluating a third configuration, with the 5 MW facility having a steam host that would offset the cost of fuel by 50%.

2.4.4 Developing budgetary, rough order-of-magnitude (ROM), factored, capital cost estimates for the three configurations based on major equipment pricing received plus Harris Group historical pricing for the balance of equipment.

2.4.5 Developing the operations and maintenance (O&M) scope of the study only to the extent necessary to support a budgetary O&M cost for the pro forma based on Harris Group historical data.

2.4.6 Developing a budgetary financing analysis with a breakeven analysis for the three configurations incorporating the capital cost, O&M costs, and the predicted power sales prices developed by EKI.

2.4.7 Developing a project report reflecting the work performed and the results of the Study.

SECTION 3 – DESCRIPTION OF PRELIMINARY PROCESS DESIGN / TECHNOLOGY SELECTION

3.1 PLANT CONFIGURATION

This Study evaluates two plant sizes to determine the economic and technical feasibility of building a woody biomass-fueled cogeneration facility on a former saw mill site in Pablo. A simple heat and material balance was initially developed for each of the two plant configurations; 3.5 MW (net output) and 20 MW (gross output). An important input into the final heat balance for any cogeneration plant is the quantity and quality of energy being exported. The initial cogeneration host was thought to be heating for nearby Tribal buildings. However, after economic evaluation, the cost for the 1.5-mile-long pipelines combined with the cost to convert the existing heat-pump-based heating systems to use the thermal energy could not be justified by the potential savings. Table 3.1 summarizes the installation costs for both steam and hot water piping systems to the campus, with additional information in Appendix F. We did investigate other hosts near the site, but they did not require enough energy to warrant the cost of cogeneration. The study then became a three-option study:

- Option 1 – A 20 MW net output electrical biomass plant without cogeneration
- Option 2 – A 5 MW gross output plant without cogeneration
- Option 3 – A 5 MW gross output combined heat and power (CHP) plant associated with an onsite saw mill as a steam host

Table 3.1 – Preliminary – Steam/Hot Water Header

PRELIMINARY – STEAM/HOT WATER HEADER	Steam Header Line	Hot Water Header Line
Installed ROM GST	$3,800,000	$2,500,000
Supply Line – Header Only	6 inches	6”
Condensate/Return Line	3 inches	6”
Steam Traps	Yes	N/A
Expansion Joints	Yes	Yes
Vaults	Yes	Yes
Backup Packaged Boiler	Not Included	Not Included
Building Equipment Adds	Not Included	Not Included
Distribution Lines	Not Included	Not Included

Notes:

1. Routing of Main Header Only – Plum Creek to government buildings.
2. Have not assumed crossing Highway 93 (to high school or college).
3. Assumed 6-1/2 feet deep and 8,860 feet long.

3.2 TECHNOLOGY SELECTION

A technology study was performed to determine the combustion technology best applicable to the particular size of the boiler. Biomass gasification, stoker, bubble bed, and circulating fluid bed boiler technologies were reviewed to determine the level of commercial development, efficiency, installation and maintenance costs, and emissions potential.

The gasification technology was eliminated, based on lack of operating installations in these boiler size ranges, which outweighed any slight advantage on price and efficiency. The industry leans toward stoker-fired packaged boilers in the smaller 1-to-10 MW range, where, at 20 MW, the stoker or bubble bed boilers are the preferred technologies.

Based on the results of the study, the 5 MW options have been evaluated based on a stoker-fired packaged fire tube boiler, and the 20 MW option was evaluated based on a field-erected bubble bed boiler to take advantage of the slight efficiency and emissions improvement over a stoker-fired boiler.

Equipment quotes for the three considered boiler technologies are included in Appendices A, B, and C, with a summary table of the boiler comparisons is provided in Appendix D.

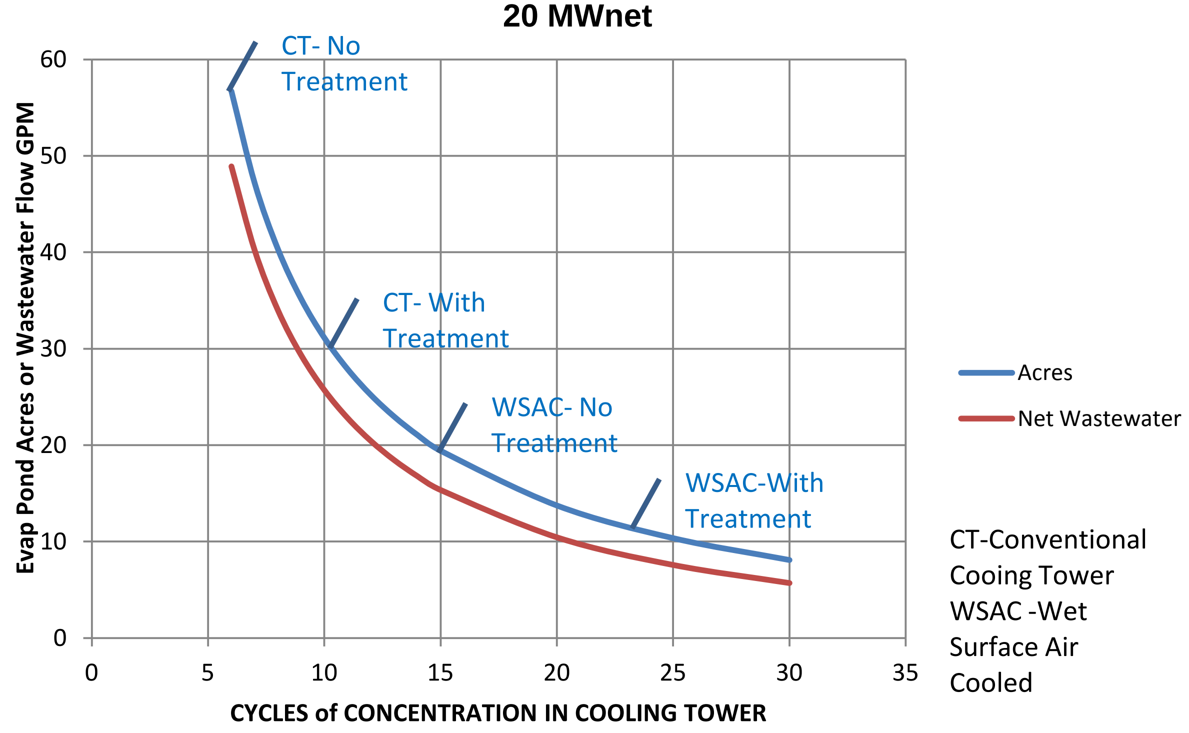
3.3 PRELIMINARY DESIGN

The heat and material balances were developed based on the energy host, boiler technology information and the boiler efficiencies and steam conditions provided in the boiler proposals. The balances are presented in Appendix D.

A wet surface air-cooled condenser (WSACC) was selected as the preferred heat rejection equipment because the cost of installation is competitive with conventional wet cooling towers while offering a significant reduction in wastewater generation. The design of the WSACC prevents evaporation of the cooling water on the heat exchanger surface and, therefore, it is capable of using water with considerably more dissolved solids. This capability reduces the blow-down frequency of the system; consequently reducing the volume of wastewater produced.

The existing sawmill site is limited to 10 gallons per minute of wastewater discharge into the city sewer system. Any additional wastewater needs to be either evaporated or transported offsite. The reduced cooling system wastewater blow-down from the WSACC during summer operation coupled with the ability to operate in a dry mode during two or three cold months significantly reduces the size of the evaporation pond required to handle the excess wastewater. Figure 3.1 summarizes the cooling system blowdown versus evaporation pond size.

Figure 3.1 CT vs. WSACC Evaporation Pond Size
Cycles of Concentration VS Evaporation
20 MWnet



Plant arrangement drawings for each option are included in Appendix G. The fuel handling and storage systems differ significantly between the two plant sizes. The 20 MW plant includes an automated fuel handling system from truck dumping into the boiler fuel feed system, which reduces operator involvement and management of the fuel storage.

The 5 MW plant design is based on a manual system where the fuel is dumped from the delivery truck to the ground and either moved to storage or fed to the boiler via a front-end loader requiring nearly around-the-clock operator involvement. Fuel must be manually reclaimed from the storage pile to fill the boiler feed system every few hours to maintain fuel to the boiler. Costs for mobile equipment are not included in the capital cost estimates, as this equipment is typically leased.

3.4 ELECTRICAL PRELIMINARY INTERCONNECTION

3.4.1 Existing Tie-In

The existing 69 kV tie in is made through a .25 mi pole line connecting the existing A frame to the existing 336.4 aluminum conductor steel reinforced (ACSR) line running along the East side of the site. This line ties into the Kerr Dam #3 substation via the Polson substation.

The existing A frame includes a disconnect switch and a 100E fused switch. This fused switch connects to the existing 7.5/9.375 MVA 67 kV to 4.16 kV transformer. The secondary side of the transformer is connected through tubular bus and a disconnect switch to the main 4160-volt (V) bus, which includes approximately seven disconnect switches with up to a 400A rating.

The 20 MW plant would be connected to the grid via a new switchyard and substation, as the existing on-site electrical equipment is incapable of handling the load. The 5 MW option uses an existing transformer to step up the generator output voltage to the required interconnect voltage.

The attached electrical one-line drawings provide a summary of how each plant would be connected to the grid and the protections would be included.

3.4.2 20 MW Project Tie-In (see Drawing E540001, Appendix E)

In this option, the electrical generator would be rated 13.8 kV so a new 69 kV – 13.8 kV generator step-up (GSU) transformer would be required.

The existing A frame could be reused, although it may be necessary to upgrade the existing .25-mile tie line.

A new substation extending east from the A frame would be designed including a 69 kV breaker with disconnects, two PTs, a surge arrestor, and transformer. The breaker is required to protect the 69 kV line up to the Polson and Pablo substations, to protect the GSU transformer, and to open in case of a 13.8 kV bus fault. The relay equipment required to provide this protection would be located near the 13.8 kV switchgear within the process building.

The transformer would be connected to the 13.8 kV switchgear via non-segregated phase bus. The bus would be tapped to feed the station service 13.8 – 4160 V transformer. Differential protection located near the 13.8 kV switchgear would protect the bus.

3.4.3 5 MW Project Tie-In (see Drawing E540002, Appendix E)

In this option, the existing A frame, transformer, and the existing 69 kV line would be reused; however, the existing secondary disconnect switch and bus would not be required.

Based on the project layout drawings, the A frame would not be relocated; however, the transformer would be moved east. A new substation extending east from the A frame would be designed, including a 69 kV breaker with disconnects, two PTs, and a surge arrestor. The breaker is needed to protect the 69 kV line up to the Polson and Pablo substations, to better protect the GSU transformer and to open on a 4160 V bus fault. The relay equipment required to provide this protection would be located near the 4160 V switchgear in the process building.

3.5 CAPITAL COST DEVELOPMENT

Major equipment lists were developed for each option that include either the quoted or estimated cost of equipment. Major equipment items quoted include steam turbine generator, fuel handling equipment, heat rejection equipment, and the boiler island, inclusive of emissions control equipment suitable for the boiler size.

Other equipment items costs are based on recent quotes for similar equipment adjusted for process conditions and escalation. The items include pumps, tanks, heat exchangers, air compressors, deaerator, water treatment, and chemical feed systems.

The detailed capital costs for each option evaluated are presented in Section 7.

SECTION 4 – FUEL SUPPLY AND ASSOCIATED ECONOMIC ANALYSIS

4.1 INTRODUCTION

The BECK Group (BECK) performed the fuel supply and associated economic analysis, and its work is summarized below. See Appendix J for the full BECK report.

The fuel supply was evaluated based on two options:

> Option 1 is a smaller plant that would use biomass fuels from Tribal lands only. (Option 1 has been named the CSKT Scenario.)
>
> Option 2 is a larger plant that would use biomass from Tribal lands, adjacent USFS lands, and other sources. (Option 2 has been named the 40-Mile Scenario.)

There are many important factors in determining the feasibility of such a project. The report focused on two key factors – the availability and delivered cost of biomass fuel. Fuel volumes are reported in bone dry tons (BDTs)[1] and delivered costs are reported in dollars per BDT ($/BDT).

4.2 ESTIMATED SUPPLY OF BIOMASS FUEL

For both scenarios, four fuel source types were considered in estimating the fuel supply. These include: 1) *logging slash*, 2) *small diameter roundwood*, 3) *mill residues*, and 4) *urban wood waste*.

4.2.1 CSKT Scenario

Table 4.1 displays the *total* and *recoverable* amount of biomass fuel estimated to be available for the CSKT Scenario. The distinction between total and recoverable is that the total volume includes everything that is estimated to be produced annually. The recoverable volume is what is estimated to be practically and cost-effectively available for use as biomass fuel. The total volume can be thought of as the extreme upper limit of the "best case" fuel availability. The "recoverable" volume can be thought of as the "best estimate" of fuel availability. As shown in Table 4.1, for the CSKT Scenario, a total of 77,200 BDT is estimated to be produced annually, of which 47,700 BDT are estimated to be recoverable annually.

Note: The CSKT Scenario supply is sufficient, even though at a high cost, to support the 5 MW plant configurations.

[1] A BDT is an amount of wood fiber weighing exactly one short ton (2,000 pounds) and containing zero moisture. In practice, biomass always contains some moisture. Biomass facilities take samples from incoming truckloads, measure the moisture content in the sample, and convert the truckload volume to BDTs by doing a calculation based on the moisture content of the sample. Measuring, buying, and selling fuel this way eliminates weight variation caused by moisture content.

Table 4.1 [1.1] – CSKT Scenario Estimated Total and Recoverable Annual Biomass Fuel Volume (BDT)

Fuel Source Type	Total Estimated Biomass Volume (BDT)	Recoverable Estimated Biomass Volume (BDT)
Logging Slash	19,900	10,000
Small Diameter Roundwood - PCT	14,800	8,900
Small Diameter Roundwood - FR	30,000	22,500
Mill Residues	3,200	3,200
Urban Wood Waste	9,300	3,100
Total	**77,200**	**47,700**

4.2.2 40-Mile Scenario

The following Figure 4.2 provides an aerial view of the 40-mile radius used in developing the 40-Mile Scenario fuel supply/costs.

Figure 4.2 [5.2] – Map of Counties Within the Supply Area

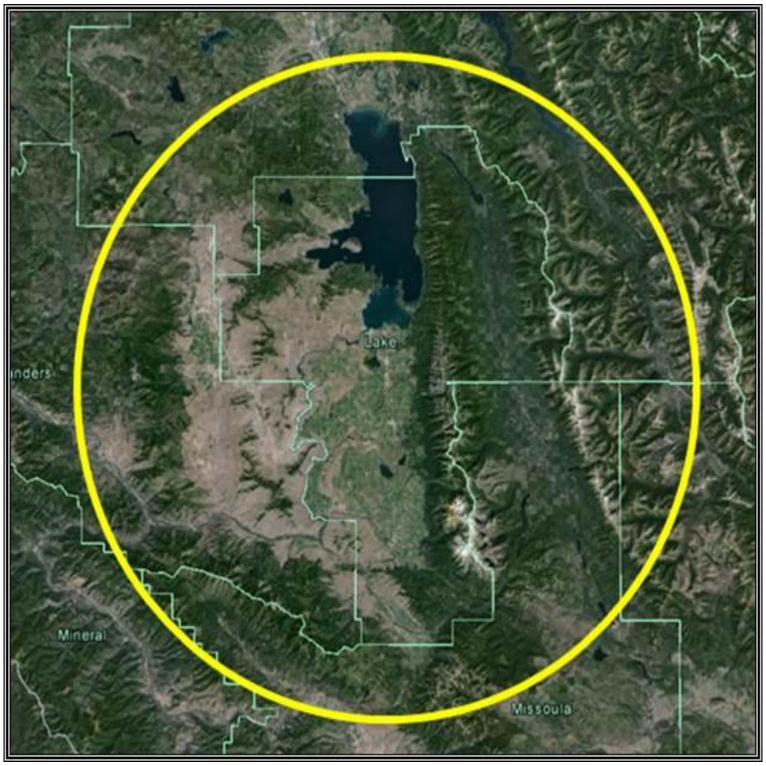


Table 4.2 displays the total and recoverable amount of biomass fuel estimated to be available for the 40-Mile Scenario. The total biomass fuel volume in this scenario is estimated to be 523,100 BDT annually, of which 363,400 BDT are estimated to be recoverable. Please note that all of the biomass volume from the CSKT Scenario is included in the 40-Mile Scenario.

Table 4.2 [1.2] – 40-Mile Scenario Estimated Total and Recoverable Annual Biomass Fuel Volume (BDT)

Fuel Source	Total Estimated Biomass Volume (BDT)	Recoverable Estimated Biomass Volume (BDT)
Logging Slash	66,100	33,300
Small Diameter Roundwood - PCT	41,900	25,200
Small Diameter Roundwood - FR	63,100	47,400
Mill Residues	320,000	246,900
Urban Wood Waste	32,000	10,600
Total	**523,100**	**363,400**

4.3 ESTIMATED DELIVERED COST OF BIOMASS FUEL

Aside from the volume of fuel estimated to be available, the second focus area of the study is estimating the delivered cost of biomass fuel. The delivered cost of biomass fuel varies depending on a number of factors, including fuel source type, moisture content, market value, and transportation cost. Because each of those factors can vary significantly, there is a considerable range in delivered fuel costs. Therefore, rather than providing just an average overall delivered fuel cost, the following tables report the estimated delivered fuel cost with fuel grouped by major fuel source type as well as the overall average.

4.3.1 CSKT Scenario

Table 4.3 displays the estimated delivered fuel costs for the CSKT Scenario. Please note that the table is arranged in such a way that it displays both the average delivered cost for each source type and the cumulative average delivered cost for each row and all rows above any given row. As shown in the table, the overall average delivered fuel cost is estimated to be $50.37 per BDT for the total recoverable volume of 47,700 BDT. However, a wide range in delivered costs by source type exists − with a low of $23.40 per BDT for mill residues and a high of $63.24 per BDT for pre-commercial thinning roundwood.

Please note that, aside from the variability in cost among fuel types, there also is variability within a type. The within-type variability primarily is a function of transportation distance, but other factors can also have an impact, i.e., different market values at different locations for mill residues, different processing costs for roundwood of different sizes, etc.

Table 4.3 [1.3] – CSKT Scenario Delivered Fuel Cost Estimate ($/BDT)

Fuel Source Type	Recoverable Volume for Each Source (BDT)	Cumulative Volume (BDT)	Delivered Cost for Each Source ($/BDT)	Cumulative Average Delivered Cost ($/BDT)
Mill Residues	3,200	3,200	23.40	23.40
Urban Wood Waste	3,100	6,300	26.09	24.72
Logging Slash	10,000	16,300	40.06	34.13
Roundwood - FR	22,500	38,800	57.06	47.42
Roundwood - PCT	8,900	47,700	63.24	50.37
Total/Average	**47,700**		**50.37**	

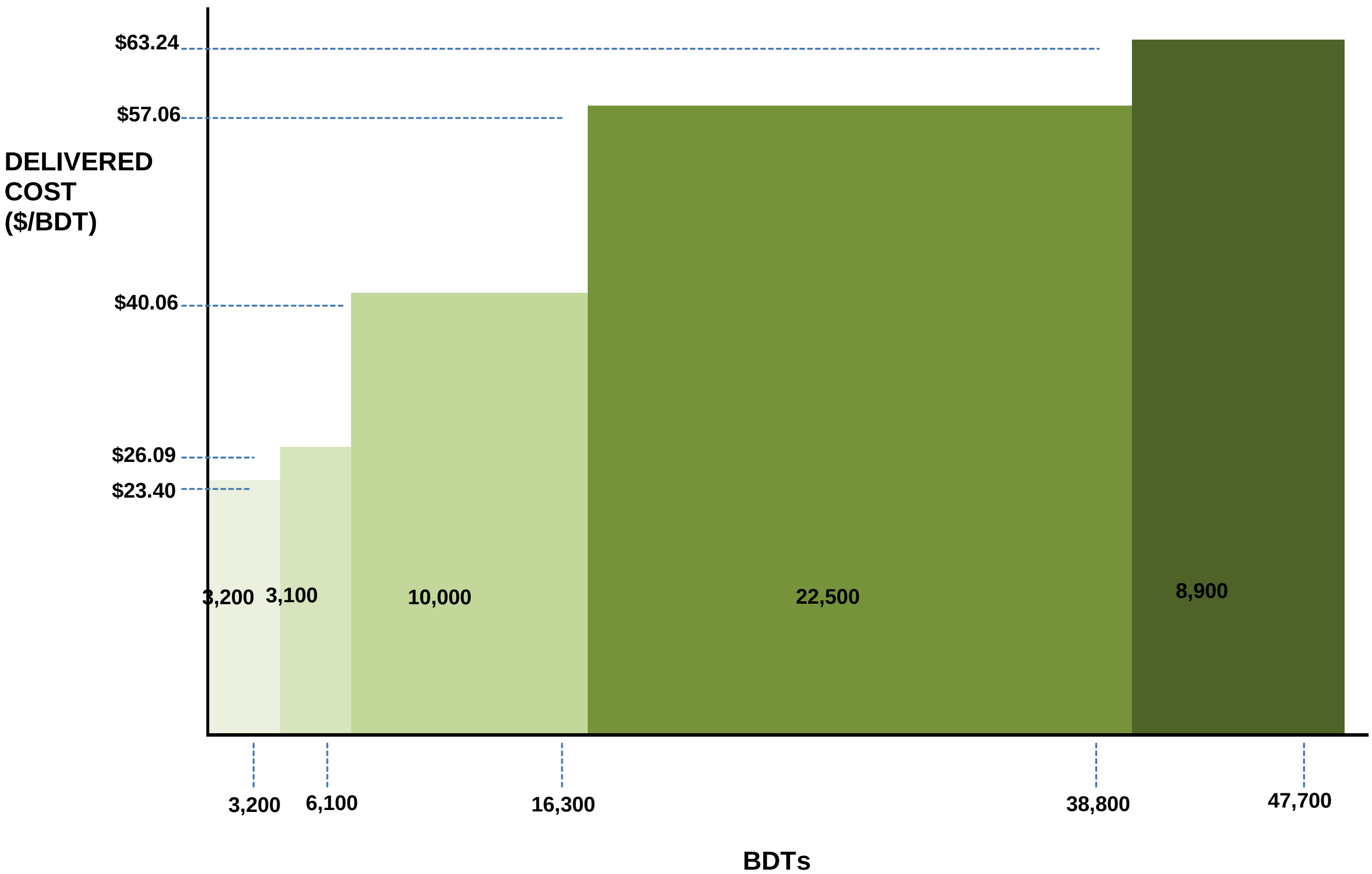
Table 4.4 [1.4], Detailed CSKT Scenario Delivered Fuel Cost Estimate, provides a more detailed categorization of the amounts and estimated delivered costs of the fuel available from the various sources. Please note that the cumulative delivered fuel cost total differs slightly from Table 4.3 because of rounding.

Table 4.4 – Detailed CSKT Scenario Delivered Fuel Cost Estimate

Source	Type	Row Volume (BDT)	Row Delivered Cost ($/BDT)	Cumulative Volume (BDT)	Cumulative Delivered Cost ($/BDT)
CSKT Dupuis Lumber	Bark/Hog	600	21.78	600	21.78
CSKT Hunt's Timbers	Bark/Hog	100	21.78	700	21.78
CSKT Foothills P&L	Bark/Hog	2,500	23.85	3,200	23.40
CSKT Urban Wood	All CSKT Scenario Sources	3,100	26.08	6,300	24.72
CSKT Logging Slash	10-Mile Haul	500	35.22	6,800	25.49
CSKT Logging Slash	20-Mile Haul	1,000	37.37	7,800	27.01
CSKT Logging Slash	30-Mile Haul	6,500	39.52	14,300	32.70
CSKT Logging Slash	40-Mile Haul	2,000	41.67	16,300	33.80
CSKT FR Roundwood	10-Mile Haul	1,125	51.67	17,425	34.95
CSKT FR Roundwood	20-Mile Haul	2,250	54.36	19,675	37.17
CSKT FR Roundwood	30-Mile Haul	14,625	57.06	34,300	45.65
CSKT PCT Roundwood	10-Mile Haul	445	57.85	34,745	45.81
CSKT FR Roundwood	40-Mile Haul	4,500	59.75	39,245	47.41
CSKT PCT Roundwood	20-Mile Haul	890	60.54	40,135	47.70
CSKT PCT Roundwood	30-Mile Haul	5,785	63.24	45,920	49.66
CSKT PCT Roundwood	40-Mile Haul	1,780	65.93	47,700	50.26
Total		**47,700**			

Figure 4.2 [1.1] displays the essentially the same information as shown in Table 4.3, but it is shown in the form of a cost curve rather than a table. The volumes shown at bottom of the figure are the cumulative totals, the volume shown in the colored areas is the volume (BDT) estimated to be available at the given price point ($/BDT).

Figure 4.2 – CSKT Scenario Supply Cost Curve



4.3.2 40-Mile Scenario

Table 4.5 displays the estimated delivered fuel cost for the 40-Mile Scenario. As shown in the table, the overall average delivered cost is estimated to be $55.11 per BDT for the total volume of 363,400 BDT. Like the CSKT Scenario, there is a wide range in delivered cost by fuel type. The lowest-cost fuel type is estimated to be urban wood waste with an average delivered cost of $38.56 per BDT, and the highest cost fuel type is estimated to be pre-commercial thinning roundwood with an estimated delivered cost of $66.72 per BDT. The reason each individual fuel source type in this scenario has a higher delivered cost than in the same fuel source type in the CSKT scenario is because of higher transportation costs in the 40-Mile Scenario.

Table 4.5 [1.5] – 40-Mile Scenario Delivered Fuel Cost Estimate ($/BDT)

Fuel Source Type	Recoverable Volume for Each Source (BDT)	Cumulative Volume (BDT)	Delivered Cost for Each Source ($/BDT)	Cumulative Average Delivered Cost ($/BDT)
Urban Wood Waste	10,600	10,600	38.56	38.56
Logging Slash	33,300	43,900	45.78	44.04
Mill Residues	246,900	290,800	54.98	53.33
Roundwood - FR	47,400	338,200	59.89	54.25
Roundwood - PCT	25,200	363,400	66.72	55.11
Total/Average	**363,400**		**55.11**	

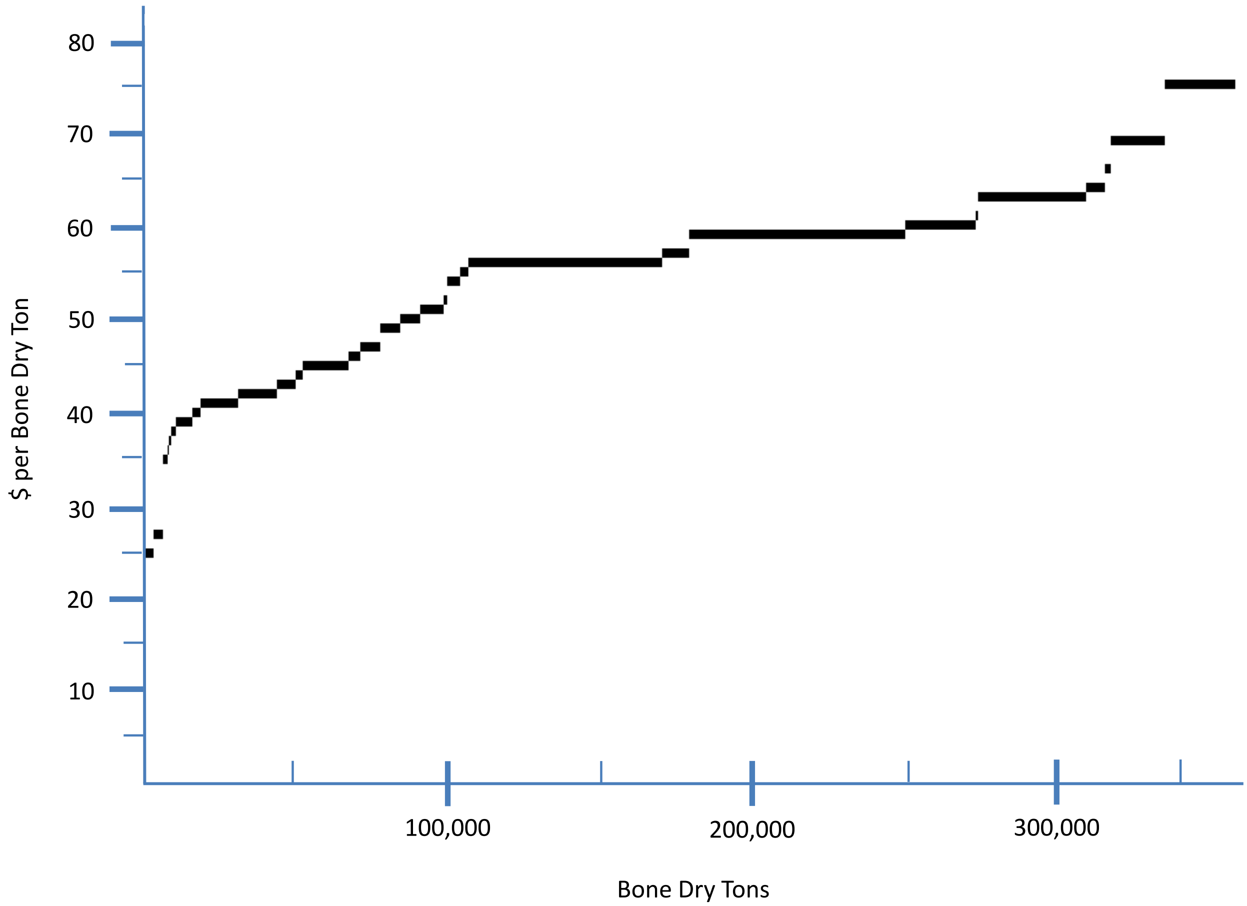
Table 4.6, Detailed 40-Mile Scenario Delivered Fuel Estimate, provides a more detailed categorization of the amounts and estimated delivered costs of the fuel available from the various sources.

Table 4.6 – Detailed 40-Mile Scenario Delivered Fuel Cost Estimate

Source	Type	Row Volume (BDT)	Row Delivered Cost ($/BDT)	Cumulative Volume (BDT)	Cumulative Delivered Cost ($/BDT)
CSKT Dupuis Lumber	Bark/Hog	600	21.78	600	21.78
CSKT Hunt's Timbers	Bark/Hog	100	21.78	700	21.78
CSKT Foothills Post and Lumber	Bark/Hog	2,500	23.85	3,200	23.40
CSKT Urban Wood	CSKT Scenario	3,100	26.08	6,300	24.72
40- Mile Plum Creek Evergreen Sawmill	Bark/Hog	900	34.52	7,200	25.94
40- Mile Plum Creek Evergreen Plywood	Bark/Hog	500	34.52	7,700	26.50
CSKT Logging Slash	10 Mile Haul	500	35.22	8,200	27.03
40- Mile Urban Wood	40 Mile Radius	700	36.25	8,900	27.76
40- Mile Plum Creek CF Sawmill	Bark/Hog	1,000	37.19	9,900	28.71
40- Mile Plum Creek CF Plywood	Bark/Hog	500	37.19	10,400	29.12
40- Mile Plum Creek Evergreen Sawmill	Shavings	5,100	38.73	15,500	32.28
40- Mile Tricon	Bark/Hog	700	38.96	16,200	32.57
40- Mile Urban Wood	Kalispell/Columbia Falls	1,800	39.03	18,000	33.21
CSKT Logging Slash	20 Mile Haul	1,000	39.34	19,000	33.54
40- Mile F.H. Stoltze	Bark/Hog	700	40.19	19,700	33.77
40- Mile Plum Creek CF Sawmill	Shavings	7,200	40.78	26,900	35.65
40- Mile F.H. Stoltze	Shavings	3,800	40.78	30,700	36.28
CSKT Logging Slash	30 Mile Haul	6,500	41.18	37,200	37.14
40- Mile Plum Creek Evergreen Sawmill	Sawdust	5,100	41.52	42,300	37.67
40- Mile Thompson River Lumber	Bark/Hog	400	41.63	42,700	37.70
40- Mile Tricon	Shavings	3,800	42.14	46,500	38.07
40- Mile Logging Slash	MT DNRC - Kalispell/Plains	2,200	42.34	48,700	38.26
CSKT Logging Slash	40 Mile Haul	2,000	43.78	50,700	38.48
40- Mile Thompson River Lumber	Shavings	2,100	44.18	52,800	38.70
40- Mile Plum Creek CF Sawmill	Sawdust	8,200	44.19	61,000	39.44
40- Mile F.H. Stoltze	Sawdust	3,800	44.19	64,800	39.72
40- Mile Tricon	Sawdust	3,900	45.96	68,700	40.07
40- Mile Urban Wood	Missoula	5,000	46.44	73,700	40.51
40- Mile Logging Slash	USFS - Lolo NF	1,200	46.90	74,900	40.61
40- Mile Logging Slash	Private - Industrial	5,700	46.90	80,600	41.05
40- Mile Logging Slash	USFS - Flathead NF	4,000	48.04	84,600	41.38
40- Mile Thompson River Lumber	Sawdust	2,000	48.63	86,600	41.55
40- Mile Logging Slash	Private - Non-Industrial	6,300	49.18	92,900	42.07
40- Mile Pyramid Mountain Lumber	Shavings	7,400	50.26	100,300	42.67
CSKT Roundwood	10 Mile Fuel Reduction	1,125	51.67	101,425	42.77
40- Mile Pyramid Mountain Lumber	Bark/Hog	1,000	51.68	102,425	42.86
40- Mile Logging Slash	MT DNRC - Swan Unit	3,900	52.59	106,325	43.22
CSKT Roundwood	20 Mile Fuel Reduction	2250	54.36	108,575	43.45
40- Mile Plum Creek Evergreen Sawmill	Chips	23,300	55.52	131,875	45.58
40- Mile Plum Creek Evergreen Plywood	Chips	36,000	55.52	167,875	47.71
40- Mile Pyramid Mountain Lumber	Sawdust	8,400	56.80	176,275	48.15
CSKT Roundwood	30 Mile Fuel Reduction	14625	57.06	190,900	48.83
CSKT Roundwood	10 Mile PCT	445	57.85	191,345	48.85
40- Mile Plum Creek CF Sawmill	Chips	22,000	58.19	213,345	49.81
40- Mile Plum Creek CF Plywood	Chips	26,000	58.19	239,345	50.72
40- Mile F.H. Stoltze	Chips	20,000	58.19	259,345	51.30
CSKT Roundwood	40 Mile Fuel Reduction	4,500	59.75	263,845	51.44
40- Mile Tricon	Chips	17,800	59.96	281,645	51.98
CSKT Roundwood	20 Mile PCT	890	60.54	282,535	52.01
40-Mile Roundwood	Fuel Reduction	24,900	62.44	307,435	52.85
40- Mile Thompson River Lumber	Chips	10,100	62.63	317,535	53.16
CSKT Roundwood	30 Mile PCT	5,785	63.24	323,320	53.34
CSKT Roundwood	40 Mile PCT	1,780	65.93	325,100	53.41
40-Mile Roundwood	Pre-Commercial Thinning	16,300	68.62	341,400	54.14
40- Mile Pyramid Mountain Lumber	Chips	22,000	74.23	363,400	55.36

Figure 4.3 displays the essentially the same information as shown in Table 4.6 but is shown in the form of a cost curve rather than a table. The volumes shown at bottom of the figure are the cumulative totals, and the volume shown in the colored areas is the volume (BDT) estimated to be available at the given price point ($/BDT).

Figure 4.3 [1.3] – 40-Mile Scenario Supply Cost Curve



4.4 DISCUSSION

BECK is not aware of any biomass projects in the planning or development phase that would affect the biomass supply estimated to be available for this project. However, there are a number of already existing biomass users, for example, sawmills that are already utilizing a portion of their mill residues as boiler fuel or a chipping plant in Bonner, Montana that uses small diameter roundwood to make chips for use in pulp and paper manufacturing.

The sawmills are not likely to greatly increase their consumption of mill residues in the future. Thus, there is likely to be little impact of their use on supply. The chipping plant, in contrast, could increase production. However, in BECK's judgment this is not likely, since chips from whole logs (the process used in Bonner) are more expensive to produce than chips produced as mill residues. Thus, as the number of housing starts recovers over the next few years, causing sawmills to increase production to historic levels, the volume of relatively low cost mill residue chips will increase, which in turn is likely to limit the number of whole log chips produced.

The moisture content of biomass fuel is also an important variable, because it affects the cost of transporting fuel and it affects the combustion efficiency of the boiler, which affects the volume of fuel needed to operate the plant. Based on BECK's experience, the assumed moisture content for the various fuel types are shown in Table 4.7 on the following page. Because of the variability in moisture content, BECK recommends that BDTs and dollars per BDT ($/BDT) be used as the units of measurement for transacting biomass purchases if a biomass project is developed by EKI.

Table 4.7 [1.7] – Estimated Average Biomass Fuel Moisture Content (%)

Biomass Fuel Type	Average Moisture Content (%)
Urban Wood Waste	20
Logging Slash	35
Mill Residues - Chips	50
Mill Residues - Sawdust	50
Mill Residues - Shavings	15
Mill Residues - Bark	50
Roundwood - FR	50
Roundwood - PCT	50

Finally, it is important to note that, for the 40-Mile Scenario, there are sub-categories within the category of mill residues, i.e., chips, sawdust, shavings, and bark. Market values for each sub-category can be quite variable, but chips generally have the highest market value, followed by shavings and sawdust, and bark usually has the lowest market value. Table 4.8 displays a breakout of the estimated delivered cost values and recoverable amounts of mill residues for the 40-Mile Scenario.

As shown in the table, the mill residue that is most likely to be economically viable for use in a CSKT biomass facility is bark/hog fuel. Unfortunately, relatively little of that material is estimated to be recoverable, because much of it already is being utilized as boiler fuel at the sawmills. A more detailed estimate of the recoverable volume and delivered cost of fuel available from each mill and by mill residue type is included in Appendix J.

Table 4.8 [1.8] – Breakout of Mill Residue Volumes and Delivered Costs for the 40-Mile Scenario

Mill Residue Type	Recoverable Volume (BDT)	Delivered Cost ($/BDT)
Chips	177,200	59.71
Sawdust	31,400	47.63
Shavings	29,400	43.20
Bark/Hog Fuel	8,900	25.59
Total/Weighted Average	**246,900**	**54.98**

4.5 FUEL SUPPLY COST ESTIMATOR

BECK has developed a fuel cost estimator spreadsheet. This has been provided to EKI for development of costs associated with the four types of biomass fuel – logging slash, roundwood, urban wood, and mill residues. The CSKT Biomass Fuel Cost Estimator is included in Appendix J.

4.6 REVIEW OF PAST STUDIES RESULTS

4.6.1 Prior Studies Specific to CSKT

In mid-March of 2014, BECK staff traveled to Polson and Pablo to kick off the biomass feasibility study project, make contacts with key EKI and CSKT staff, and gather information from prior studies. After the on-site meeting, BECK reviewed and analyzed the biomass fuel supply information from the previous studies. Table 4.9 provides a summary of the findings from studies that were specific to Flathead Reservation.

Table 4.9 [3.1] – Summary of Annual Fuel Supply Findings from Various Sources In Previous Studies Specific to CSKT

Study	Date	Logging Slash (BDT)	Forest Thinning (BDT)	Mill Residues (BDT)	Total Fuel (BDT)
T.P. Roche for S&K Holding Company	2008	7,850			7,850
University of Washington Bioenergy IGERT	August 2010	*10,000	6,880	4,000	20,880
R.W. Beck Biomass Fuel Power Plant	October 2010	**10,000	6,880	4,000	20,880
NARA Tribal Partnership	January 2014	13,120	n/a	n/a	13,120
Average		**10,243**	**6,880**	**4,000**	**15,683**

*Page 22 of the IGERT report states that a total of 19,728 BDT are available annually based on the assumption of an annual sawtimber harvest of 18.million board feet. Later in the report (page 38), it states that 10,000 BDT of logging slash are available per year. The 10,000 BDT per year figure was reported here given that the 19,728 BDT per year value does not account for any material that cannot be recovered due to limited access to landings, or timber harvesting methods that do not accumulate slash at log landings.

**Please note that the R.W. Beck study used data on biomass supply from the IGERT study.

4.6.2 Prior Studies Not Specific to CSKT

Aside from the studies that were specific to the Reservation, several additional biomass supply studies have been completed that covered an area either near, or encompassing, the Reservation. The results of those studies are summarized in Table 4.10.

Table 4.10 [3.2] – Summary of Annual Fuel Supply Findings from Various Sources In Previous Studies Not Specific to CSKT

Study	Date	Logging Slash (BDT)	Forest Thinning (BDT)	Mill Residues (BDT)	Total Fuel (BDT)
R.W. Beck Biomass Fuel Power Plant (Best Case)	December 2001	234,000	48,000	n/a	282,000
R.W. Beck Biomass Fuel Power Plant (Worst Case)	December 2001	43,000	33,000	n/a	77,000
NorthWestern Energy Western Montana (40 mile)	June 2010	61,600	n/a	26,100	87,700
NorthWestern Energy Western Montana (70 mile)	June 2010	167,700	n/a	26,100	193,800
Montana DNRC Study completed by Morgan at UM BBER	April 2009	243,514	n/a	1,500,000	1,743,514

Several important items to note about the information shown in Table 4.9 are:

- The R.W. Beck study was focused on the area included within a 60-mile radius of the Flathead Valley.
- Both a "best" and "worst" case is shown for the R.W. Beck study. The scenarios are based on differing assumptions in the development of an effective logging slash processing and transportation system and average fuel moisture content.
- The NorthWestern Energy Study identified seven sawmills in western Montana as potential sites for biomass-fueled combined heat and power projects. The fuel supply results presented in the study are the "average amount" estimated to be available at a "prototypical" site. In other words, the total amount of biomass fuel estimated to be available at all sites was divided by 7 to get the average amount available at a prototypical site.
- Regarding the "mill residues" volume reported in the NorthWestern Energy Study, the volume shown includes only bark and sawdust, because planer shavings and chips typically have higher market values for other uses,

e.g., pulp and paper production, animal bedding, or particleboard and MDF, than can be provided by converting those materials to heat and/or power. Also note that the volumes shown are the “average amount” produced at the “prototypical” western Montana sawmill. In other words, the amounts shown are not specific to any mill currently operating in western Montana.

- The Montana DNRC study estimated biomass volumes across the entire state for both logging slash and mill residues. However, the amount shown in the logging slash column includes only the annual amount estimated to be produced in Lake, Missoula, and Sanders Counties. The mill residual volume includes the amount produced at all mills across the state in 2004.

- Finally, another publicly available study was completed by Porter Bench Energy, LLC. That study evaluated biomass feasibility at four sites in western Montana, including Bonner, Columbia Falls, Fortine, and Troy, Montana. All of those sites were judged to be too distant from Pablo to provide information relevant for this study. However, it is worth noting that at all sites examined in the Porter Bench study found significant volumes (> 75,000 BDT) of logging slash to be available annually.

4.6.3 Conclusions Based on Information From Prior Studies

All of the prior studies included in the current review found significant volumes of biomass fuel to be available from a variety of sources. However, the volume available from each source is largely dependent on the level of economic activity occurring within the forest products industry. For example, during times of weak lumber demand there also are lower levels of timber harvesting and, therefore, less available logging slash. Similarly, there are fewer mill residuals (bark, sawdust, planer shavings, and chips) available during weak lumber markets. Most of the studies reviewed are five or more years old.

Over the last five years, there has been considerable change in Montana’s forest products industry, including, perhaps most significantly, the closure of Smurfit Stone’s Frenchtown, Montana, pulp and paper mill. Other permanent closures include two Plum Creek sawmills (Pablo and Fortine) and a finger-joint lumber plant in Libby, Montana.

Anecdotally, it has also been reported that, during the economic downturn, a number of logging and trucking contractors have sought employment in the booming production of oil and natural gas in eastern Montana and western North Dakota. The result has been reported shortages of logging and hauling contractors. The shortage of this important skilled labor pool should be a consideration in any further analysis of practical availability of biomass.

SECTION 5 – TRIBAL BUILDINGS ENERGY USAGE ASSESSMENT

5.1 INTRODUCTION

During the analysis of the feasibility of co-generation biomass power production on the Reservation, Harris Group performed an energy usage assessment of various tribal buildings. These included the government buildings of the CSKT, the buildings of the Salish and Kootenai College (SKC) and the Two Eagle River High School facility. The following is a summary of the work that was performed.

5.2 SITE VISITS

Harris Group completed site visits to all three campuses in April. While on site, Harris Group inspected all of the buildings and reviewed each of the mechanical heating and ventilation systems. The government buildings, the college buildings, and the high school were toured. Based on these inspections, Harris Group identified three types of fuel used to provide heat to these buildings:

- Electricity – Three types of electric components provide heat in these buildings:
  - Elements.
  - Air source heat pumps.
  - Water source heat pumps.
- Oil – burned to heat water or air.
- Propane – burned to heat air in a packaged roof top unit.

5.3 BUILDING DESCRIPTIONS

CSKT Government: Several government buildings are large enough to consider heating them with steam from the proposed CHP facility. These include the one-story complex building, the two-story complex building, the new complex building, and the law and order government building. Several other buildings are simply too small, with too little heat requirement, to warrant the cost associated with steam supply. These buildings include the Head Start child care building, the day care building, the janitorial building, and several others.

It was indicated that the CSKT government has been replacing the propane-fired heating units with air source heat pumps. These heat pumps save energy and are less costly to operate. Three buildings use propane for heating, and one building uses an oil-fired furnace. The remaining buildings use electric heat supplied primarily by heat pumps.

SKC: The college campus buildings also range widely in size, and several of the buildings are too small with too little heat requirement to warrant the cost associated with steam supply.

Many of the college buildings are heated with air source heat pumps, while a few are still heated via propane. It was indicated that, as the propane-fired heaters wear out, they are being replaced by heat pumps. Some of the newer buildings have water source heat pumps. As a general rule, propane heaters are the least efficient of these three options. Air source heat pumps are more efficient, and water source heat pumps are the most efficient. Air source heat pumps are most efficient when the weather is warm; however, as the temperature drops, so does the efficiency of the unit. Eventually, it becomes too cold for air source heat pumps to provide heat, and an electric element is used to provide the heat.

Two Eagle River High School: The high school is heated primarily using a heating water loop. The circulating water is heated using an oil-fired boiler and an electric boiler. Heating oil is expensive, and the oil-fired boiler is about as efficient as propane-fired heaters.

5.4 CALCULATIONS

To complete the energy analysis, Harris Group performed calculations to determine how much energy is necessary to heat these buildings. We entered the size of the building into a computer model estimating the size and number of windows, doors, etc., and the insulation values of the walls and roof. The software uses the weather data to calculate how much heat is required for each of the buildings. Harris Group received drawings for a few of the buildings; however, drawings were not available for many of the buildings. We used Google Earth to determine the approximate size of these buildings. Using the photographs from the site visits, we made estimates for windows and doors. We entered this data into the computer software to calculate the heat required for each of the buildings. We used this method for the larger buildings on each of the campuses.

Using the heating numbers for the larger buildings, we calculated how many BTU/square foot were used to heat the buildings. This number then was used to estimate the heat requirement for the smaller buildings.

The calculations determined the peak demand for heat in BTU/hour as well as the total BTU of heat required for the entire year. The BTU/hour peak demand was used to determine the size of the steam pipe that would be required from the biomass facility. The BTU/year value was used to calculate how much money would be saved by heating with steam instead of the existing units.

As of May 21, 2014, the price for electricity is $0.031/kWh, the price for heating oil is $3.69/gallon, and the price for propane is $1.37/gallon.

The calculated results can be found in the attached Appendix K, with a summary in Table 5.1 below.

Table 5.1 – Analysis of CSKT Government, College, and High School Buildings

Bldg No.	Campus	Bldg Name	Annual Heating Load (kBtu/yr)	Existing Heat Type	Estimated Total Cost per Year
51	College	Agnes Kenmille	225,000	Propane	3,387.36
52	College	Paul Charlo	141,750	Propane	2,134.04
53	College	Agnes Vanderburg	157,500	Electric AS HP	511.06
54	College	Baptiste Mathias	157,500	Electric AS HP	520.36
55	College	Michel	441,000	Electric AS HP	1,457.00
56	College	D'Arcy McNickie	806,906	Assume 75% Propane and 25% HP	5,031.35
57	College	Child Care Services	213,750	Electric AS HP	706.20
58	College	Academic Success	180,000	Electric AS HP	594.69
59	College	John Peter Paul	543,357	Electric AS HP	1,795.17
60	College	Big Knife	478,762	Assume 50% Propane and 0% HP	4,748.56
61	College	Three Wolves	220,500	Propane	3,319.62
63	College	IMSI	94,500	Electric AS HP	312.21
65	College	Woodcock	725,762	Assume 25% Propane and 75% HP	9,929.99
66	College	Late Louie Caye Sr.	171,000	Electric AS HP	564.96
67	College	Beaverhead	1,152,724	Electric AS HP and WS HP	2,756.10
68	College	Adeline Mathias	706,657	Water Source HP	2,334.69
69	College	Education	498,864	Electric HP	1,648.17
80	College	Silver Fox Golf Club House	121,500	Assume 50% Propane and 50% Electric	1,316.01
81	College	Transportation	191,250	Electric Water Heater	631.86
82	College	Joe McDonald Health & Fitness Center	1,557,250	Electric AS HP	5,144.92
83	College	Johnny Arlee/Victor Charlo Theater	279,900	Electric AS HP	924.75
84	College	Enrollment/Bookstore/Aux. Services	626,552	WS Heat Pump	1,498.05
420	Government	Headstart/College Dr	152,550	Electric HP	504.00
440	Government	Complex – 2 Story	880,117	Propane	13,250.11
440	Government	Complex – 1 Story	453,467	Electric HP	1,498.19
441	Government	Law & Order	446,705	Electric HP	1,475.85
443	Government	Sylvia's Store	72,000	Electric HP	237.88
444	Government	Property & Supply	324,844	Electric HP	1,073.23
445	Government	Probation	216,000	Electric HP	713.63
446	Government	ECS/Daycare	135,000	Electric HP	446.02
448	Government	Evenstart/Fatherhood/Janitorial	47,520	Oil	1,518.31
450	Government	CPS/Social Services	202,500	Electric HP	669.03
451	Government	Maint/P&S Surplus	108,000	Electric HP	356.82
454	Government	People Center	344,918	Propane	5,192.72
460	Government	New Complex West	1,525,275	Propane	22,962.93
---	High School	Two Eagle High School	2,496,780	Oil	79,774.60
		TOTALS	**17,096,850**		**180,940**

With the current low price of electricity, the overall cost for heating the buildings is relatively low. As the units are transitioned from propane to heat pumps, the cost for heat will continue to decline. Currently, the calculated cost for heating the buildings for a single year is approximately $180,940.

5.5 SUMMARY

Harris Group has performed an energy analysis on the buildings that make up the government complex, the college campus, and the high school. After we performed this analysis and combined the results with the estimated costs for the installation of the steam delivery piping system and equipment (per Harris Group PM 01), **we determined that the installation of a steam supply and distribution system has insufficient payback to justify the capital investment**.

The most cost-effective option appears to be the continuation of the current program of converting propane-fueled heaters to heat pumps as the existing propane heaters wear out. The high school also would benefit from utilizing its electric boiler as much as possible and minimizing the use of the oil boiler.

SECTION 6 – SITE ASSESSMENT

6.1 SITE

The former Plum Creek Timber sawmill in Pablo was identified as the primary site for a proposed co-generation biomass power production facility. The SKC campus was initially evaluated as a possible location; however, it was quickly realized that due to the limited acreage combined with the significant increase in truck traffic around the campus it would not be a viable site option. The Plum Creek site includes two sections separated by a rail line running through the property. The abandoned sawmill is situated in the section east of the tracks, which has several buildings and infrastructure in place but would require upgrades for the new facility. The portion of the property to the west of the tracks has abandoned greenhouses with minimal infrastructure in place.

Both sections of the property were evaluated as possible locations for the biomass plant, and, after analysis, it was decided that the property on the east side of the tracks provides the better infrastructure and minimized the connection distances to the required utilities.

6.2 ACCESS

The Plum Creek site is located alongside US Highway 93, a divided highway that bisects Pablo. The northern boundary of the property has a county road that ties in to the US 93, allowing for delivery of the fuel supply to the site with minimum road improvements. Road access onto the site remains in place from when the previous mill was in operation. This infrastructure will reduce capital investments necessary to support the delivery of the biomass fuel.

6.3 BUILDINGS

One or two of the several on-site buildings have potential for biomass plant use. For now, we have assumed new buildings. Should the site be selected, a more detailed evaluation of reusing existing buildings is recommended.

6.4 WATER / SEWER

Water is available from the city via multiple on-site wells. In order to access the city sewer, customers are required to have a water meter installed and purchase water from the district. The off-site connection to the water system and the sewer is within a reasonable distance to the southeast. The demand for process water is high, and our evaluation includes connection to the city water and sewer system for 10 gpm, with the balance supplied by on-site water wells. We have included a site plan of the Plum Creek property, showing the city water and sewer approximate connection points (see sketch in Appendix G). In efforts to minimize cost, we have included a WSACC to reduce both the required amount of process water and the size of the evaporation pond.

6.5 ELECTRICITY

The eastern section of the property contains a substation with transformers. This will be the interconnection point for the plant auxiliary power as well as for the export power.

Valley Electric, the local utility, owns the transformers. We made contact with Valley Electric to coordinate the use of this interconnection point and were advised that the substation could be used as long as the new owner/customer upgrades the substation. For both the 5 MW and the 20 MW biomass plant cost estimates, we have included the upgrades to the substation to accommodate the import and export of power through this substation.

6.6 FIRE WATER

The existing site has a fire water loop in place that would require modifications to accommodate the new plant. It appears that some of the existing system can be re-used. Because the original fire pumps have been removed and the building is in disrepair, we have included new fire pumps and a new fire pump house in the project estimate.

6.7 SITE LAYOUT

The Plum Creek site is situated on a large parcel of land at the outskirts of the City of Pablo. The nearest residence is north of the site, and a reasonable distance from the biomass facility to the residence can be maintained. Additionally, some mature trees will buffer noise levels that may increase due the addition of the biomass plant.

The size of the property provides adequate area for the addition of an evaporation pond required for the process.

Even though it is currently not required, the rail line that crosses the property provides for future business opportunities in developing the site beyond the biomass energy project.

6.8 SITE ENVIRONMENTAL ASSESSMENT

A site geotechnical report was not available. Existing foundations indicate that the foundation designs should be of normal/standard design. This study does not provide for any underground investigation, which should be considered in the next phase if the project moves forward. In the next phase, an evaluation of the site for buried items or substances, i.e., hazardous wastes, etc., that require cleanup will have to be made.

Building permits and approvals from the City should be of a normal nature with minimum impact on the project.

The site has a stormwater pond, which may be re-used and expanded as needed for the biomass plant.

6.9 AIR PERMITTING

6.9.1 Air Permitting Preliminary Findings

Air permitting requirements were reviewed for both the 5 MW and 20 MW configurations.

Two types of regulations have to be considered to permit and complete a co-generation facility:

1. Regulations that apply to the source's direct emissions. For example, a steam generator ≥ 30 MMBtu/hr heat input can emit no more than 0.03 lbs of particulate matter per million BTU of heat input. These standards apply regardless of stack height, fuel characteristics, etc.

2. Regulations that apply based on the impact of the direct emissions to the surrounding ambient air quality. In this situation the "Class I" designation becomes applicable. There are maximum incremental increases that are permissible for Class I areas. These are intended to protect areas such as national parks from air quality deterioration, but still allow for some additional sources. *Major* sources are reviewed under these limitations (often referred to as prevention of significant deterioration or PSD). Demonstration of compliance with the allowed increments usually is performed via dispersion modeling of the source in its physical surroundings. The direct emissions' ambient air quality impacts are a function of the emission rate, temperature, stack height, topography, meteorology, and, in some cases, interaction with ambient pollutants to form "secondary pollutants."

The EPA promulgated rules in July 2011 that are applicable to minor sources on Tribal lands. The rules have emission rates expressed in tons per year which, if exceeded, subject the source to the regulations. The rules also define how "synthetic minor" sources are to be regulated. Those rules do not appear to link *minor* sources and the need to do an evaluation of compliance with Class I increments. However, this does not mean that the EPA will not require an ambient air evaluation of criteria and/or "air toxics" under a general "SOURCE IMPACT ANALYSIS."

The 5 MW facility qualifies for advantages in the permitting process due to the lower levels of emissions. Our research indicates it would be categorized as a "synthetic minor" source based upon a potential equipment vendor's emission estimates. "Synthetic minor" sources are those with federally enforceable limits on a source's emissions or operating conditions that keep emissions below a major source threshold emission rate.

For the initial Pablo site base case (sized at 65,600 lb/hr of fuel), we assumed that the emissions would be limited to the vendor's estimates shown below in Table 6.1 in the "lb/MMBtu" column. The estimate for particulate matter is the "Boiler Maximum Achievable Control Technology (MACT)" standard for an "area" source, that is, one that is not "major." The total emissions calculated for criteria pollutants are all less than 250 tpy and greater than the minor source threshold for Tribal lands.

The vendor equipment assumed in the Table 6.1 estimate includes some type of hydrogen chloride (HCl) control. That control was sufficient at a design rate of 61,200 lb/hour fuel to ensure the emissions remained less than the 10 ton-per-year (tpy) major source threshold for HCl.

At the revised design rate of 65,600 lb/hr, the calculated HCl emissions are 10.7 tpy, slightly more than the major source threshold. If this assumed emission rate were to stand, it would have a significant impact on the project permitting. The PM emission limit would be 0.0098 lb/MMBtu, rather than 0.03 lb/MMBtu assumed by the vendor, and the unit would be subject to mercury (Hg) and carbon monoxide (CO) limits under major-source boiler MACT standards.

The ultimate classification of the 20 MW facility as major or minor source will depend on additional analysis of the fuel sources. Chloride and mercury concentrations in fuel will determine if potential emissions exceed regulatory thresholds.

If chloride and mercury concentrations are low in the source of the biomass, the HCL and Hg emissions may be lower than the 10 ton-per-year major source threshold for those hazardous air pollutants, without add-on control. This would be determined early in the project from elemental analyses of a representative sample of potential fuel suppliers.

Table 6.1 – Air Emissions Levels

	Vendor boiler emission estimates at revised firing rate						Major Source MACT limit	IC Minor Source Theshold
Criteria Pollutants	lb/MMBtu	MMBtu/hr	hr/yr	lb/hr	tpy	ISSUE	lb/MMBtu	tpy
NOx	0.1	0	8760	-	0.0			10
NOx w/ SCR	0.04	0	8760	-	0.0			10
Total PM	0.03	0	8760	-	0.0	> MACT if major source	0.0098	10
Filt. PM10	0.01	0	8760	-	0.0			5
Total PM2.5	0.025	0	8760	-	0.0			3
Filt. PM2.5	0.01	0	8760	-	0.0			
CO	0.1	0	8760	-	0.0		0.27	10
SO2	0.02	0	8760	-	0.0			10
VOC	0.03	0	8760	-	0.0			5
HAP Pollutants								
Mercury	Not quantified					no MACT limit if area source	8.00E-07	
HCl	0.0088	0	8760	-	0.0	> MACT; major source HAP	0.0022	
MACT	maximum achievable control technology							
IC	Indian country regulations, Fed.Reg. Vol. 76, No. 127, 7/1/2011					.		

6.9.2 Regulatory Contacts

After a brief conversation with Randy Ashley, program manager for the Natural Resources Department CSKT, we were directed to EPA Region 8 in Denver, as CSKT has not been delegated authority for permitting within the reservation. We made contact with Matthew Lagenfeld of the Tribal Air Section in Denver. He confirmed that the Pablo site is within the reservation. We then determined that the Pablo site is not within the two moderate PM-10, non-attainment areas near Ronan and Paulson in Lake County. Thus, the PSD threshold for major pollutants would still be 250 tpy.

6.9.3 Permitting

Two forms must be submitted to EPA as the reviewing authority in order for the project to be permitted.

1. "Form New" – The master form for the project, containing the information about the source and tabulating the potential and actual emission estimates.
2. "Form SynMin" – In addition to the criteria pollutants, the "SynMin" form requires information on greenhouse gases (GHG) expected from the project. As the GHG emissions for the 20MW project exceed 250 tpy, a PSD review will be required for GHG emissions.

Our preliminary research indicates:

- The EPA would be the reviewing authority
- Permit application will involve at least the two forms listed above.
- Air pollution control technologies required are as provided in vendor proposals received.

Based on our research and vendor proposals, the following controls are included:

20 MW – Baghouse, SNCR, and combustion control

5 MW – Cyclone separation and ESP

SECTION 7 – CAPITAL COST ESTIMATES

7.1 COST ESTIMATE

The capital cost estimates were produced using a combination of vendor proposals for major equipment, baseline project data, in-house estimating guidelines and historical data. This estimate has been escalated to fourth quarter 2014 U.S. dollars using appropriate construction cost indices and standard installation labor hours. The costs were adjusted for conditions unique to this facility, i.e., site characteristics, labor supply, level of vendor erection, etc. The cost estimate includes engineering, procurement, and construction (EPC) costs for process equipment and materials, equipment installation, structural excavation and backfill, concrete foundations and slabs, structural steel, piping, electrical equipment, and instrumentation and control equipment.

Tables 5 MW 7-1 and 20 MW 7-1 provide a summary of the detailed cost estimate for the 5 MW option and the 20 MW option respectively. These estimates are based on the current conceptual project documents, such as: process flow sheets, initial equipment lists, and vendor equipment quotations. See Appendix L for additional detail of the capital cost for the 5 MW and 20 MW facilities.

This conceptual level estimate evaluates the option to install a 5 MW biomass power generation facility near Pablo. The estimated capital cost for this scenario is $37,649,334 or $7,530/KW (gross output). The capital cost difference between the 5 MW full condensing option and the 5 MW combined heat and power (CHP) option is not detectable at this level of estimate detail.

7.2 BIOMASS FACILITY CAPITAL COSTS

7.2.1 5 MW Biomass Power Generation Facility

5 MW Table 7-1 – Estimated Capital Costs

Description	Totals (x $1,000)	
Equipment Costs	$	14,233
Other Plant Direct Costs	$	11,984
Field Indirect Costs	$	4,006
Owner Construction Management	$	446
Engineering	$	1,825
Commissioning and Start-up	$	456
Equipment Spares	$	75
Substation Upgrade	$	1,000
Sales Tax	$	0
Contingency	$	3,423
Subtotal EPC	**$**	**37,649**

Given the current level of the design and the estimating approach used, the accuracy of this type of estimate is considered to be -15%/+30%, assuming minimal variation to the equipment list following the issuance of this estimate revision. The estimate includes EPC costs inside the plant boundary with no costs included for items beyond the plant boundary.

7.2.2 20 MW Biomass Power Generation Facility

This conceptual level estimate evaluates the option to install a 20 MW biomass power generation facility near Pablo. The estimated capital cost for this scenario is $117,989,914 or $5,899/kW (net output).

20 MW Table 7- 1 – Estimated Capital Costs

Description	Totals (x $1,000)	
Equipment Costs	$	49,975
Other Plant Direct Costs	$	26,562
Field Indirect Costs	$	18,487
Owner Construction Management	$	954
Engineering	$	6,203
Commissioning and Start-up	$	1,431
Equipment Spares	$	250
Substation Upgrade	$	3,000
Sales Tax	$	0
Contingency	$	10,726
Subtotal EPC	**$**	**117,990**

A detailed explanation of the items in Tables 5 MW 7-1 and 20 MW 7-1 are as follows:

Equipment Costs – Includes major equipment items (steam turbine generator (STG), material handling equipment, boiler, vessels, pumps, etc.) along with auxiliary equipment (storage tanks, etc.), plus 4% for freight.

Other Plant Direct Costs – Includes installation costs (field labor, material and subcontractor costs), site development (excavation and backfill, fencing, and access roads), utilities, and buildings. For this estimate, the labor hours were adjusted using a productivity factor of 1.0. The labor hour composite labor rate was adjusted to $33.87 for site location to reflect the Fourth Quarter 2014 average labor rate for Great Falls, Montana, which is the nearest data point to Pablo. Note that no allowance has been made for air freight expenses.

Field Indirect Costs – Includes field supervision, indirect labor, payroll burdens, per diems, consumable supplies, small tools, construction equipment, field services, temporary facilities, construction power, mobilization, and demobilization, and contractor normal overhead and profit. These labor costs include locally hired support personnel.

Miscellaneous Costs – Includes vendor technical assistance for major equipment, including the boiler, STG, etc. Some vendor assistance usually is included in the equipment cost

Engineering – Includes home office engineering costs based on in-house historical data and reflects the requirements of executing engineering and procurement for this scope of work.

Construction Management – Included in field indirect costs and including supervision, small tools and consumables, construction equipment, offices, etc.

Commissioning and Start-up – Includes management and execution of commissioning and start-up sequences, first fills, craft labor support, and supervision.

Equipment Spares – For the 5 MW case, an allowance of $75,000 has been included for equipment spares required during commissioning and start-up. For the 20 MW case, an allowance of $250,000 has been included for equipment spares.

Substation Upgrade – This is a budget to upgrade an existing substation on the project site. No additional transmission costs are included.

Sales/Use Tax – No sales/use tax is included in the estimate.

Contingency – Contingency normally is added to an estimate to compensate for items included in the scope that have yet to be identified. These result from incomplete design and unforeseen or unpredictable conditions in the project scope. Additional contingency should also be allowed by the Owner to allow for potential changes in process conditions or requirements.

7.2.3 Construction Scope

In preparing this estimate, we made several assumptions concerning the construction scope. These assumptions include the following:

Earthwork – Includes foundation excavation and backfills and site prep.

Piling – No piles have been included in the estimate (site-specific geotechnical information was not available at the time of this study).

Concrete – The installation factors include supply, placement, and finishing of concrete foundations for equipment and structural steel.

Structural Steel – The installation factors include supply and erection of structural steel.

Mechanical Equipment and Platework – The installation factors include supply and erection of equipment and platework.

Piping – The installation factors include installation of all below-ground and above-ground piping systems, including fire protection systems, leak testing, and field fabrication as required. Piping with a 2.5-inch or larger diameter will be shop-fabricated, and piping with a 2-inch or smaller diameter will be field-fabricated, unless on module(s).

Electrical – The installation factors include supply and installation of the transformers, circuit breakers, motor control centers, motor starters, and other electrical equipment as required. Supply and erection of the following electrical systems: power generation and control; communication; fire alarm and detection; lighting; heat tracing, grounding and lightning protection; and termination and testing of the above equipment and systems are also included.

Instruments and Controls – The installation factors include supply and installation of instrument panels and programmable logic controllers, distributed controls, field-mounted instruments, related instrument bulk materials, and testing and calibration of related instruments and systems.

Buildings – Supply and erection of all process and infrastructure buildings and enclosures.

Painting and Coatings – The installation factors include supply and application of paint and specialized coatings, including touch-up paint.

Insulation – Installation factors include supply and installation of insulation for buildings, equipment, and piping.

Utilities and Services – Equipment for a continuous emissions monitoring system, air compression/distribution system, demineralized water system, and raw water system has been quantified, priced, and factored in the equipment detail sheet.

Fencing – Includes supply and erection of safety and security fencing around the perimeter of and within the site.

7.2.4 Material Quantity Basis

In preparing the factored estimate, we made several assumptions concerning the material quantity basis. These assumptions include the following:

Earthwork – Facility earthwork quantities and costs were included in the installation factors. These items include site grading, excavation, topsoil stockpiling, backfill, fencing, gravel and asphalt roads and parking areas, etc.

Concrete – Concrete quantities were included in the installation factors.

Structural Steel – Structural steel quantities were included in the installation factors.

Buildings/Architectural – Buildings were sized in accordance with preliminary concepts.

Equipment – Equipment quantities were based on Harris Group's calculations and experience. An allowance for auxiliary equipment yet to be identified has been added for items such as miscellaneous pumps, cranes, totes, etc.

Piping – Piping quantities and costs were included in the installation factors.

Electrical – Electrical equipment items and costs were included in the installation factors.

Instrumentation and Controls – Instrumentation costs were included in the installation factors.

Painting and Coatings – Painting and coatings costs were included in the installation factors.

Insulation – Insulation costs were included in the installation factors.

7.2.5 Equipment Pricing Basis

In preparing the factored estimate, we made several assumptions concerning costs associated with the material and equipment required to construct the project. These assumptions include the following:

Equipment – Vendor-proposed or quoted values were utilized for most major equipment items. Pricing of the remaining equipment was generated using in-house data; an allowance of 5% was added to cover additional unlisted equipment that will be added as the design develops and unknown spare requirements.

7.2.6 Assumptions and Exclusions

This cost estimate is based on several assumptions, including:

The project will be constructed using local labor.

Contractors will have free and unobstructed access to the site.

Excavation materials can be re-used as compacted structural fill, and excess can be stockpiled or disposed of on-site.

No blasting will be required for site preparation.

The site is free and clear of above- and below-grade obstructions and hazardous or toxic waste material.

All earthwork materials of construction, such as crushed rock and bedding material, are available locally.

A normal schedule sequence will be executed.

All work performed by the Owner that interfaces with engineering, procurement, construction, start-up, and commissioning work will be completed when scheduled.

Standard one-year warranties are included in equipment prices.

When no budget quotations were received for equipment or when listed equipment was not sized, we made assumptions with regard to size and price in accordance with our in-house or published data or historical records for similar plants.

Adequate construction materials, equipment, and labor will be available in a timely manner. No early equipment delivery premiums have been included.

A substation is on the project site; no additional high-voltage transmission lines will be required.

On-site construction management and commissioning and start-up costs have been included.

The following items have been excluded from the cost estimate:

Provision of any permits, royalties, or licenses.

Land acquisitions and rights-of-way.

Environmental liabilities.

Financing charges.

Work beyond the battery limits.

Owner project development/management costs have not been included.

Project escalation after Fourth Quarter 2014.

Furnishings, supplies, computers, software, etc.

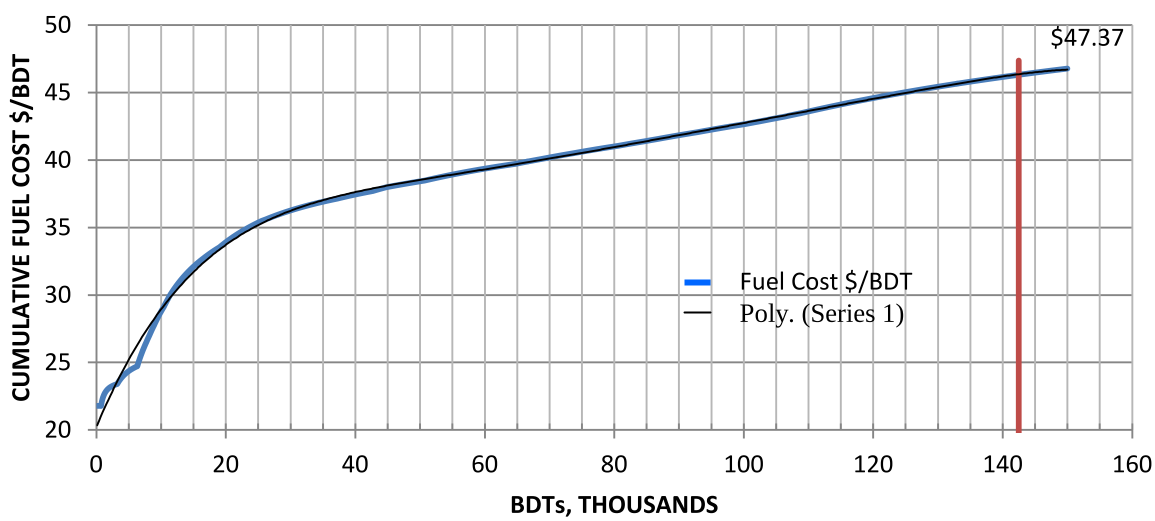
Mobile operating equipment (forklifts, trucks, loaders, dozers, etc.).

SECTION 8 – LONG-TERM OPERATING AND MAINTENANCE PLANS

The operating and maintenance expenses were estimated in two categories: variable operating expenses and fixed operating and maintenance expenses. We approached the estimates for the 20 MW option and the two 5 MW options in a similar manor with adjustments made to account for the nominal size of the facility and differences in operations.

Variable operating expenses include biomass fuel, reagents for emissions control, ash disposal, start-up fuel, and miscellaneous chemicals. Biomass fuel costs are based on the BECK report of July 2014. An equation was developed for each of the two fuel scenarios to predict the delivered fuel cost based on the annual usage. Figure 8-1 shows the fuel cost associated with the 40-mile scenario, 20 MW facility and Figure 8-2 shows the fuel cost associated with the CKST Scenario, 5 MW facility. Figure 8.3 provides a fuel cost estimate for the 5 MW cases based on fuel within the 40-mile radius, this figure is provided merely as a reference as the fuel costs used to develop the 5 MW plant economics were based on the CSKT Scenario data.

Figure 8-1 Fuel Cost for 20 MW Case



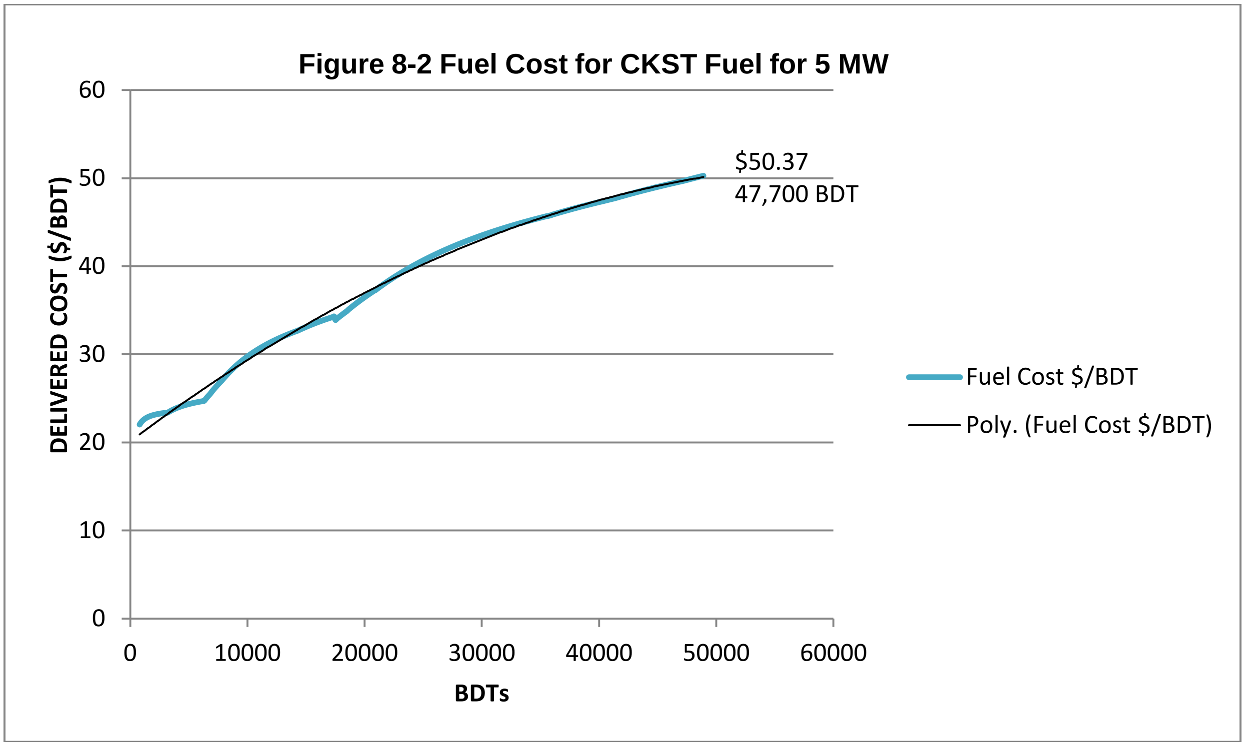


Figure 8-2 Fuel Cost for CKST Fuel for 5 MW

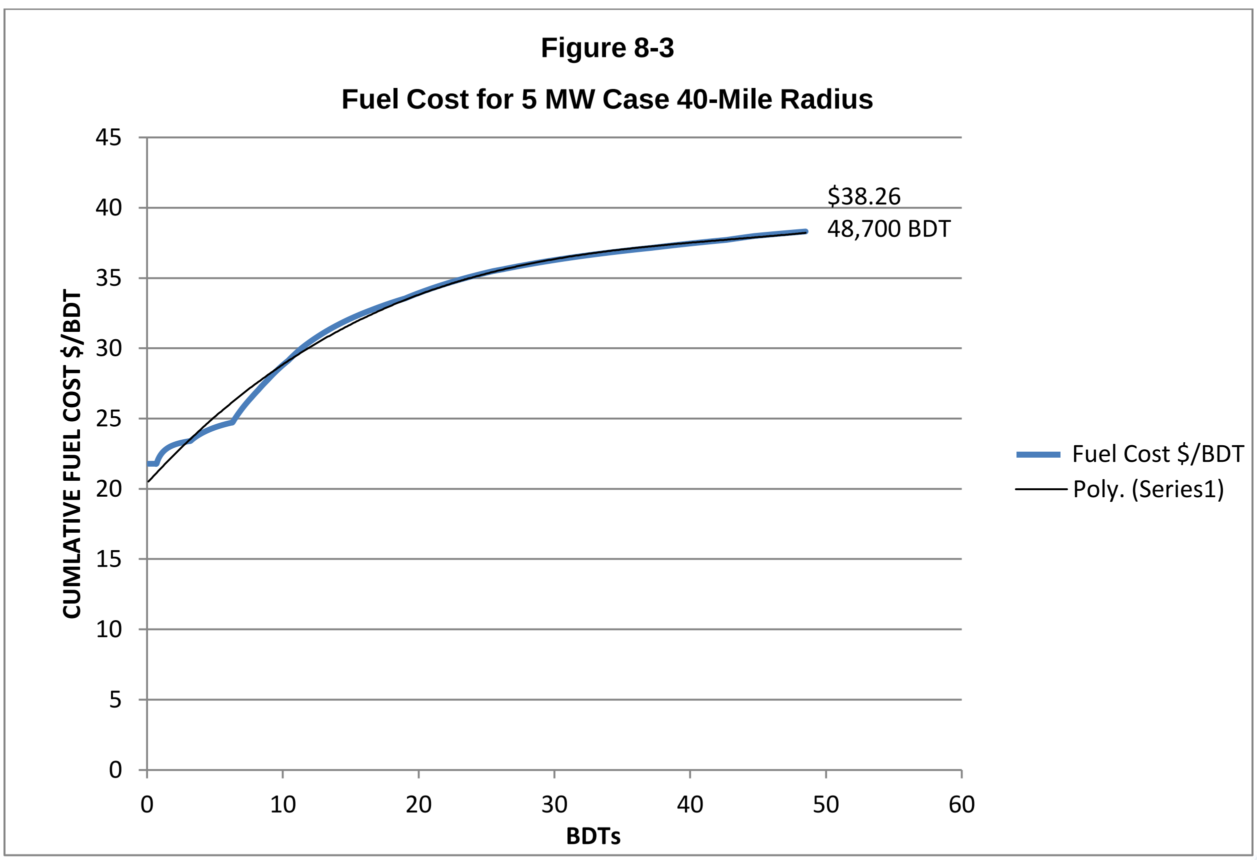


Figure 8-3

Fuel Cost for 5 MW Case 40-Mile Radius

Limestone or lime is a reagent used in industrial boilers to capture sulfur dioxide (SO_2). Neither limestone nor lime is required for either the 20 MW or 5 MW options, as the SO_2 emissions are expected to be less than the limits for these sizes of biomass-fired facilities. Ammonia or urea is injected in the boiler flue gas from the 20 MW boiler to reduce mono-nitrogen oxides (NO_x) emissions below expected limits. Sand or other inert material must be fed to the bubbling bed boiler to improve the heat transfer in the combustor due to the low ash content of biomass fuel.

The usage rates for ammonia and sand are calculated based on the ANDRITZ boiler proposal and scaled linearly based on boiler steam output. The cost of the ammonia is based on 2013 actual delivered pricing for a 30 MW plant in California. The cost of sand is based on USGS 2010 Minerals Yearbook average price for sand in the western United States.

Ash disposal is based on typical hog fuel ash content of 2% plus a 50% margin to account for dirt, rocks, and other inert materials in the fuel or sand added to the combustor. The start-up fuel oil is used to preheat the boiler to a temperature that allows the biomass material to sustain combustion. The cycle chemicals include the chemicals required to protect the boiler, WSACC, and other cycle equipment from scaling and corrosion. We based the fuel oil and chemical costs on the average cost for the last four years of a 35 MW solid fuel plant in Montana, scaled based on nominal megawatt output. We have summarized variable operating expenses in Table 8.1 for the 20 MW option, Table 8.2 for the 5 MW CHP option, and in Table 8.3 for the 5 MW full condensing option.

Fixed operating and maintenance costs include labor for operations and management, long-term maintenance and parts, professional fees for technical consultants, legal and outside accounting services, property taxes, licenses, insurance, management fees, and other miscellaneous costs. We estimated contract labor using typical construction trade labor and benefits rates for 2014 for similar trades to the operators, mechanics, and electricians.

We assumed that the annual wages for the plant manager and other office-staff-based similar positions in a typical technical office. The total first-year O&M labor and benefits of $2,480,050 equates to an average of $91,854 per employee, based upon 27 employees, and is in line with the 35 MW plant located in Montana.

Staffing is based on four operating crews to support 24-hour operation seven days per week, utilizing a 12-hour shift schedule. Each operating crew includes a control room operator, a roving operator, and fuel and ash technician, a mechanic/auxiliary operator, and an electrician/instrumentation/network technician. We have summarized other management and administration positions in Table 8.1. Benefits range from $10 to $15 per hour. We expect to need 18 employees for the 5 MW option; we can accomplish this number by reducing the number of employees on a crew to three and combining some of the management and administrative positions. A breakout of the labor costs for each option is shown in Tables 8.1, 8.2, and 8.3.

Expenses for operating and maintenance non-labor repair and maintenance, insurance, property taxes, legal, and professional fees are based on the average of the last four years of actual annual costs for a 35 MW fluid bed boiler generating plant in Montana, scaled based on nominal output to the two biomass plant sizes in this study. Non-labor repair and maintenance includes materials and parts used by the plant personnel for plant maintenance, as well as contract services to perform scheduled maintenance, major repairs, and overhauls. Total non-fuel-production-related O&M expenses equate to approximately $43.60 per MWh for the 20 MW plant and $102.22 per MWh for the 5 MW options.

Table 8.1
20 MW Option Operating and Maintenance Cost Estimate

Operating Expenses, Variable			Annual		BDT/yr	As fired T/yr	Moisture
	Fuel		$ 7,228,666	.0458 $/kWh	155,882	283,421	45%
	Limestone		None				
	Ammonia		$ 643,000	0.0041 $/kWh	14	gal/hr	1400 $/ton
	Sand		$ 19,000	0.0001 $/kWh	2	ton/day	29 $/ton
	Ash Disposal		$ 191,000	0.0012 $/kWh	1,941	lb/hr	25 $/ton
	Fuel Oil/Startup fuel/Misc Chemicals		$ 140,000	0.0009 $/kWh			
Total Variable Operating Expenses			$ 8,221,666	0.0063 $/kWh			
Operating Expenses, Fixed							
	O&M Contract Labor		$ 2,480,050	0.0157 $/kWh			
	O&M non-labor		$ 1,440,000				
	Professional fees		$ 1,300,000		Based on 4 year average of actual costs for		
	Property, license and other taxes		$ 140,000		a 35 MW solid fuel plant in Montana;		
	Insurance		$ 230,000		adjusted based on net output		
	Management fee		$ 100,000				
	Other		$ 190,000				
Total Fixed Operating Expenses			$ 5,880,050	0.0373 $/kWh			
	Total O&M Cost		$ 14,101,716	0.0894 $/kWh			
	Total Non - Fuel O&M Cost		$ 6,873,050	0.0436 $/kWh			
	Total Non-fuel non-labor Cost		$ 4,393,000	0.0279 $/kWh			
	Total O&M Cost per kWh, $/kWh			0.0894 $/kWh			
	Net Generation, MW	20					
	Net Annual Generation, kWh	157,680,000					

Fuel Cost Summary					
	Row Delivered Cost, $/BDT	Incremental Quantity, BDT	Cumulative Quantity, BDT	Cumulative-delivered cost $/BDT	
	55.52	23300	131875	45.58	Fuel cost from BECK report July 2014 page 7
			155175	46.37	
	55.52	36000	167875	47.71	

The equation developed to estimate fuel cost based on quantity, results in a lower value. The lower fuel cost is used in the evaluation

Ash Disposal Summary					
	% Ash in fuel	2%			
	% Dirt/other etc	1%			
	Total disposal	3%		8503	Tons/yr
	$/ton fuel			$ 0.75	
	$/ton BD fuel			$ 1.36	

Labor Cost Detail					
	Staff	Quantity	Rate with benefits	Hours/yr/Crew	Annual
	A Operators	4	$ 36.55	2479	$ 366,726.34
	B Operators	4	$ 34.34	2479	$ 343,021.16
	Maint Techs / Mechanics	4	$ 41.65	2288	$ 380,523.52
	Fuel &Ash Handlers	4	$ 32.26	2479	$ 320,750.87
	Electric Systems / Controls Tech	4	$ 39.22	2288	$ 361,828.48
	Plant Manager	1	$ 70.00	2080	$ 145,600.00
	Operations Superintendent	1	$ 50.00	2080	$ 104,000.00
	Maintenance Superintendent	1	$ 50.00	2080	$ 104,000.00
	Admin Asst.	1	$ 30.00	2080	$ 62,400.00
	Accountant	1	$ 35.00	2080	$ 72,800.00
	Plant Eng/ Environ	1	$ 60.00	2080	$ 124,800.00
	Fuel/Purchasing Agent	1	$ 45.00	2080	$ 93,600.00
	Total	27			$ 2,480,050
	Overtime, %				
	Operators	13%			
	Maintenance	10%			

Table 8.2
4.25 MW CHP Option Operating and Maintenance Cost Estimate

		Annual		BDT/yr	As fired T/yr	Moisture
Operating Expenses, Variable						
Fuel		$ 941,877	.0281 $/kWh	47,611	86,566	45%
			Project assumption- 50% of fuel is free from adjacent mill			
Limestone		None				
Ammonia		NO SNCR	0.0000 $/kWh	0	gal/hr	1400 $/ton
Sand		Stoker Fired	0.0000 $/kWh	0	ton/day	29 $/ton
Ash Disposal		$ 58,000	0.0017 $/kWh	593	lb/hr	25 $/ton
Fuel Oil/Startup fuel/Misc Chemicals		$ 60,000	0.0018 $/kWh			
Total Variable Operating Expenses		$ 1,059,877	0.0035 $/kWh			
Operating Expenses, Fixed						
O&M Contract Labor		$ 1,682,376	0.0502 $/kWh			
O&M non-labor		$ 760,000				
Professional fees		$ 560,000		Based on 4 year average of actual costs for		
Property, license and other taxes		$ 60,000		a 35 MW solid fuel plant in Montana;		
Insurance		$ 100,000		adjusted based on net output		
Management fee		$ 75,000				
Other		$ 75,000				
Total Fixed Operating Expenses		$ 3,312,376	0.0989 $/kWh			
Total O&M Cost		$ 4,372,252	0.1305 $/kWh			
Total Non - Fuel O&M Cost		$ 3,430,376	0.1024 $/kWh			
Total Non-fuel non-labor Cost		$ 1,748,000	0.0522 $/kWh			
Total O&M Cost per kWh, $/kWh			0.1305 $/kWh			
Generation, MW	4.25					
Net Annual Generation, kWh	33,507,000					

Fuel Cost Summary

Row Delivered Cost, $/BDT	Incremental Quantity, BDT	Cumulative Quantity, BDT	Cumulative-delivered cost $/BDT	
54.36	2250	19675	37.17	
		23806	39.57	Fuel cost from Beck report July 2014 page 4
57.06	14625	34300	45.65	

Ash Disposal Summary

% Ash in fuel	2%		
% Dirt/other etc	1%		
Total disposal	3%	2597	Tons/yr
$/ton fuel		$ 0.75	
$/ton BD fuel		$ 1.36	

Labor Cost Detail

Staff	Quantity	Rate with benefits	Hours/yr/Crew	Annual
A Operators	4	$ 36.55	2479	$ 366,726.34
B Operators	4	$ 34.34	2479	$ 343,021.16
Maint Techs / Mechanics	1	$ 41.65	2392	$ 99,380.32
Fuel &Ash Handlers	4	$ 32.26	2479	$ 320,750.87
Electric Systems / Controls Tech	1	$ 39.22	2392	$ 94,896.88
Plant Manager	1	$ 70.00	2080	$ 145,600.00
Ops Superintendent	0	$ 50.00	2080	$ -
Maint and Ops Superintendent	1	$ 60.00	2080	$ 124,800.00
Admin Asst./Accountant	1	$ 30.00	2080	$ 62,400.00
Accountant	0	$ 35.00	2080	$ -
Plant Eng/ Environ/Fuel Agent	1	$ 60.00	2080	$ 124,800.00
Fuel/Purchasing Agent	0	$ 45.00	2080	$ -
Total	18			$ 1,682,375.57
Overtime, %				
Operators	13%			
Maintenance	15%			

Table 8.3

4.25 MW Condensing Option Operating and Maintenance Cost Estimate

Operating Expenses, Variable			Annual		BDT/yr	As fired T/yr	Moisture
	Fuel		$ 2,084,328	.0622 $/kWh	42,865	77,937	45%
	Limestone		None				
	Ammonia		NO SNCR	0.0000 $/kWh	0	gal/hr	1400 $/ton
	Sand		Stoker Fired	0.0000 $/kWh	0	ton/day	29 $/ton
	Ash Disposal		$ 52,000	0.0016 $/kWh	534	lb/hr	25 $/ton
	Fuel Oil/Startup fuel/Misc Chemicals		$ 60,000	0.0018 $/kWh			
Total Variable Operating Expenses			$ 2,196,328	0.0033 $/kWh			
Operating Expenses, Fixed							
	O&M Contract Labor		$ 1,682,376	0.0502 $/kWh			
	O&M non-labor		$ 760,000				
	Professional fees		$ 560,000		Based on 4 year average of actual costs for		
	Property, license and other taxes		$ 60,000		a 35 MW solid fuel plant in Montana;		
	Insurance		$ 100,000		adjusted based on net output		
	Management fee		$ 75,000				
	Other		$ 75,000				
Total Fixed Operating Expenses			$ 3,312,376	0.0989 $/kWh			
	Total O&M Cost		$ 5,508,703	0.1644 $/kWh			
	Total Non - Fuel O&M Cost		$ 3,424,376	0.1022 $/kWh			
	Total Non-fuel non-labor Cost		$ 1,742,000	0.0520 $/kWh			
	Total O&M Cost per kWh, $/kWh			0.1644 $/kWh			
	Generation, MW	4.25					
	Net Annual Generation, kWh	33,507,000					

Fuel Cost Summary					
	Row Delivered Cost, $/BDT	Incremental Quantity, BDT	Cumulative Quantity, BDT	Cumulative-delivered cost $/BDT	
			40135	47.7	
	60.54	890	42865	48.63	Fuel cost from Beck report July 2014 page 4
	63.24	5785	45920	49.66	

Ash Disposal Summary					
	% Ash in fuel	2%			
	% Dirt/other etc	1%			
	Total disposal	3%		2338	Tons/yr
	$/ton fuel			$ 0.75	
	$/ton BD fuel			$ 1.36	

Labor Cost Detail

Staff	Quantity	Rate with benefits	Hours/yr/Crew	Annual
A Operators	4	$ 36.55	2479	$ 366,726.34
B Operators	4	$ 34.34	2479	$ 343,021.16
Maint Techs / Mechanics	1	$ 41.65	2392	$ 99,380.32
Fuel &Ash Handlers	4	$ 32.26	2479	$ 320,750.87
Electric Systems / Controls Tech	1	$ 39.22	2392	$ 94,896.88
Plant Manager	1	$ 70.00	2080	$ 145,600.00
Ops Superintendent	0	$ 50.00	2080	$ -
Maint and Ops Superintendent	1	$ 60.00	2080	$ 124,800.00
Admin Asst./Accountant	1	$ 30.00	2080	$ 62,400.00
Accountant	0	$ 35.00	2080	$ -
Plant Eng/ Environ/Fuel Agent	1	$ 60.00	2080	$ 124,800.00
Fuel/Purchasing Agent	0	$ 45.00	2080	$ -
Total	18			$ 1,682,375.57
Overtime, %				
Operators	13%			
Maintenance	15%			

SECTION 9 – ECONOMIC ANALYSIS OF PROJECT OPTIONS

9.1 MODEL STRUCTURE AND CONTENTS

Harris Group has prepared three financial models for the study, one for each of the options being considered, which are attached in Appendix M. The financial model considers the Project for a period of 20 years with a full year of operation assumed for 2018. This matches the predicted power sales prices provided by EKI. Harris Group used the results of the technical portions of the study as the technical inputs to the financial model, including capital costs, production capacity, availability, production efficiency, operation and maintenance costs, and sales revenues. Our model does not include analyses of financing assumptions, income taxes, depreciation, amortization, or commodity markets and pricing.

In this analysis, we made certain assumptions with respect to conditions that may exist or events that may occur in the future. Such assumptions depend upon future events and actual conditions may vary from those assumed. In addition, we have relied on some information provided to us by sources that we believe to be reliable. To the extent that actual conditions may vary from those assumed herein or provided to us by others, actual results may vary from those projected in the financial model.

9.2 MODEL ASSUMPTIONS

We based projected annual operating revenues and expenses on certain assumptions, including capacity, availability, and feedstock usage as discussed below. We included the effects of RECs and carbon offset credits (COCs) in the annually adjusted power price from the model developed by EKI. These credits are subject to availability for the project and, if they change, this analysis should be revised. This analysis is based on a non-leveraged approach to project financing to simplify the analysis.

9.3 GENERATION AND CAPACITY FACTOR FOR THE 20 MW OPTION

The financial model estimates full-year energy output to be 157,680 MWh throughout the term of the model. The net generating capacity is 20 MW, and the annual energy output is based on an average of 329 operating days per year. The number of operating days used in the financial model assumes 14 days of planned outage and an additional 22 days for unplanned outages or an overall capacity factor of 90%. We believe that the plant can achieve this operating level over the life of the Project, but it will be difficult to achieve in the first two years of operation. Table 20 MW Table 9-1 summarizes the net energy export plan for the Project included in the financial model.

20 MW Table 9-1 Net Energy Export	
Parasitic and Capacity	
Gross Output MW	**22.18**
Less Parasitic Load MW	(2.18)
Net Output Before Capacity	20
Capacity Percentage	100%
Net Saleable Output MW per Hour	**20**
Net Operating Hours per Year	**7884**
Annual Energy Export MWh	**157,680**

We prepared an internal electrical load list within the equipment list. The internal load or parasitic load is the internal electrical demand that is consumed by the plant during operations. The net electrical output is the gross generating capacity less the internal load.

We based the internal load study on information from the preliminary design and budget quotations from equipment suppliers. It should be expected that, as the detailed design proceeds, electrical loads will be more definitive and will more accurately reflect the actual conditions. The estimate used represents an internal load of 9.5 percent of the maximum output. We would expect to see internal loads for a biomass plant of similar scope, size, and design to be 9 to 12 percent range.

9.3.1 Revenues

Revenues used in the financial model are shown in Table 20 MW Table 9-2.

20 MW Table 9-2 Projected Revenues	
Revenue Source	**$/MWh**
Power Revenue provided by EKI (first year)	$29.21
Average Power Revenue over 20-Year Life	$63.65

The power revenue of $29.21 per MWh is the wholesale price expected to be received by EKI in the first year of operation. The rate has been escalated at 2% for the duration of the model. EKI completed a power market study to determine the most beneficial method of marketing the power produced at the facility. The analysis looked at the value of the energy, including RECs, and COCs based on five markets. The highest average power price results by selling power into Washington State as a package. The financial model uses the annual average power price for the Washington REC case for each year, resulting in the average price of $63.65 per MHh from 2018 through 2037 or 20 years. (EKI calculated an average of $65.59 per MWh over 21 years from 2018 through 2038). A sensitivity analysis was run on the power price effect on Internal Rate of Return (IROR) and is presented in 20 MW Figure 9.1.

9.3.2 Expenses

Expenses for the Project comprise fuel costs, ash disposal, non-fuel-based operation and maintenance costs, and Owner's costs. The costs for woody biomass fuel per ton, as projected in the Woody Biomass Supply Study of July 2014, starts at $46.37/BDT, which is a blended rate based on the available fuels from sources within a 40-mile radius to meet the total annual demand of 142,485 BDT per year. The first-year fuel cost is escalated at a rate of 0.75% annually thereafter.

Operating expenses for operating and maintenance labor, non-labor repair and maintenance, insurance, property taxes, and legal and professional fees are based on the average of the last four years' actual annual costs for a 35 MW fluid bed boiler generating plant in Montana, scaled to fit the 20 MW biomass plant. See Section 8 of this report for more detail on O&M expenses. Total non-fuel production-related O&M expenses equate to approximately $43.10 per MWh. O&M labor was escalated at 2.25% per annum, while non-labor repair and maintenance, as well as miscellaneous and G&A, was escalated at 1.5%.

Fuel usage projections in the financial model are consistent with the predicted performance that was provided by ANDRITZ as part of its proposal. The ANDRITZ proposal was based on a slightly smaller boiler size of 164,000 pounds of steam per hour that was solicited early in the study. The adjusted 20 MW net boiler requires a maximum continuous rated (MCR) boiler output of 177,485 pounds per hour of steam, which supports the turbine/generator's output of 22,183 gross kW. The ANDRITZ bubbling fluid bed boiler efficiency of 73% is assumed constant when scaling the quoted boiler to the larger boiler. This results in fuel input of 32.86 tons per hour based on a 45 percent moisture content at MCR. Increases in fuel moisture content have the effect of raising the fuel delivered cost. A sensitivity case has been run to compare the plant fuel cost with the internal rate of return, is discussed later in this report, and shown in 20 MW Figure 9-5.

9.3.3 Financial Model Conclusions

Feedstock usage projections are consistent with the material balances and vendor equipment's expected performance conditions.

The fuel costs shown in the financial model are consistent with the blended costs developed from the fuel availability study, but the moisture content can drive the quantity of fuel required. Moisture content can vary throughout the year.

The planned operation of 329 days per year should provide adequate allowance for the performance of normal required maintenance (planned outages), along with 22 days of unplanned outages. It is likely that if maintained properly and staffed by knowledgeable and trained personnel, the plant can achieve this operating rate over the life of the project.

We did not account for Project long-term financing in the model.

We have performed the financial analysis using the technical results from this study as inputs to the financial model, including capital costs, operating levels, fuel supply projections, and annual operating and maintenance and reasonable costs assumptions for a 20 MW biomass facility. **The financial model projects that Project revenues are insufficient to cover the operating costs for the plant and will not provide a return on the investment.** A breakeven evaluation is provided in the sensitivity analysis portion of this section.

9.3.4 Sensitivity Analysis

Due to uncertainties inherent in relying upon assumptions and projections, it should be anticipated that actual operating results could differ from those conditions assumed and described herein. We have prepared five sensitivity cases, as presented in 20 MW Table 9-3, which demonstrate the impact of certain circumstances on the financial model results. Sensitivity cases presented herein are intended to reflect the range of impact on the accuracy of the assumptions and estimates on the project.

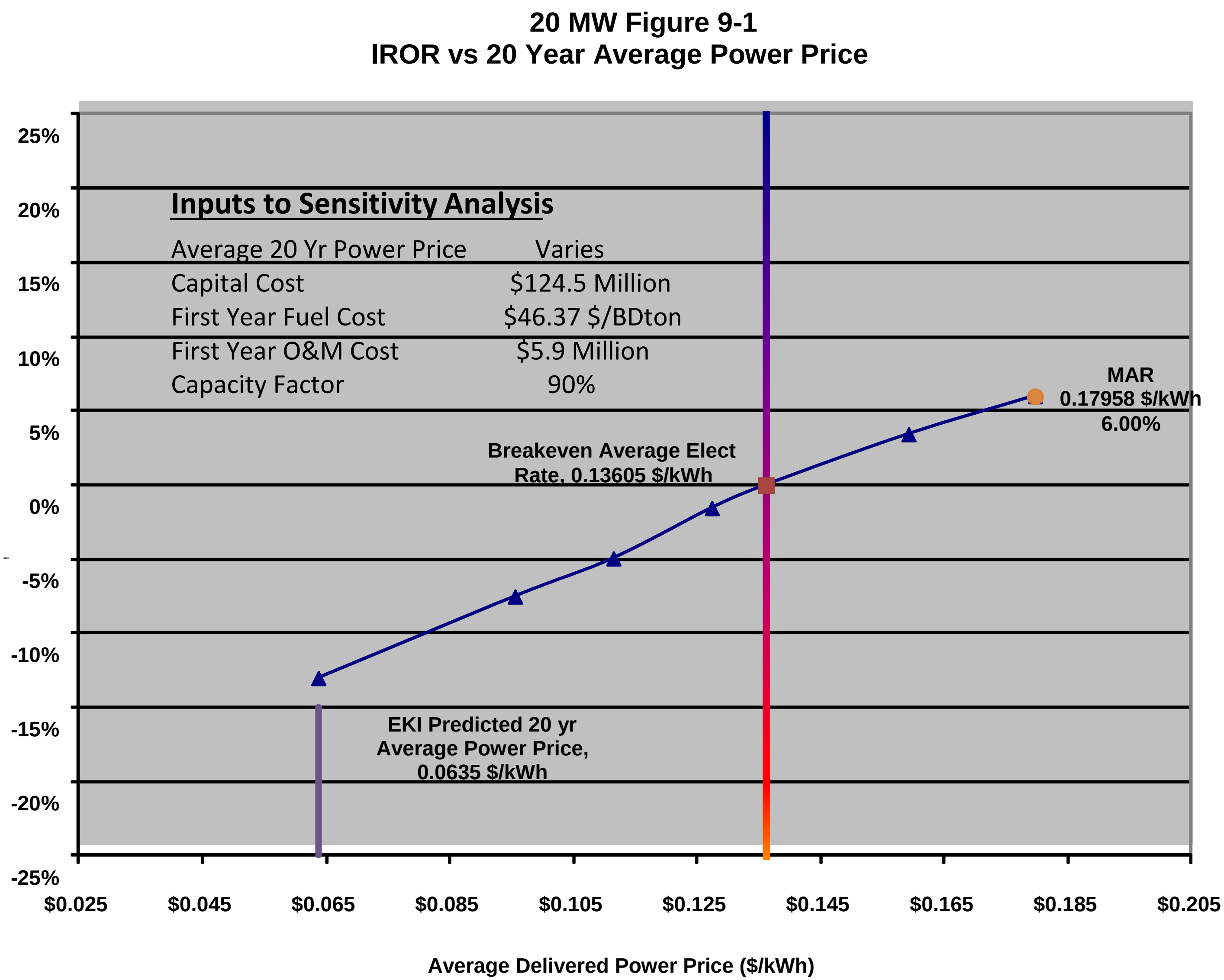
20 MW Table 9-3
Sensitivity Analysis

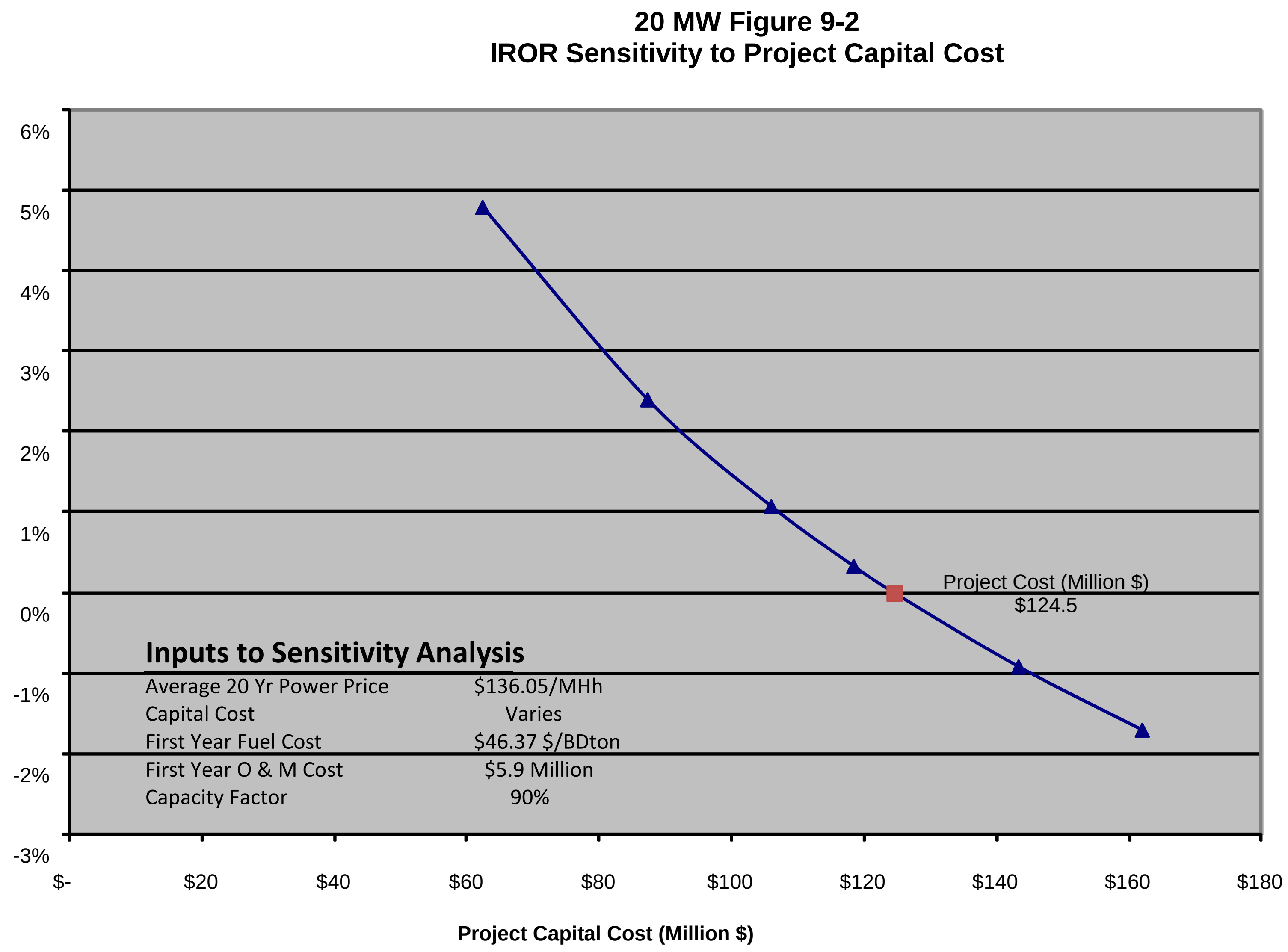
Sensitivity	First-Year Cash Flow/IROR	20th-Year Cash Flow
Base Case	$-9,065,641/ **NA**	$ -803,550
Breakeven Power Revenue (BPR) 2.14x Modeled	$-3,826,344/ **0.0%**	$17,548,804
Power Revenue at 2.82x Modeled Values	$-676,592/ **6.00%**	$28,581,839
Capital Cost at 70% of Estimate @ BPR	$-3,826,344/ **2.41%**	$17,548,804
Fixed O&M Costs at 70% @ BPR	$-2,062,239/ **2.05%**	$19,873,985
Fuel Cost at 70% @ BPR	$1,844,110/ **2.16%**	$19,833,408
80% Plant Capacity Factor @ BPR	$-4,028,409/ **-1.62%**	$14,744,924

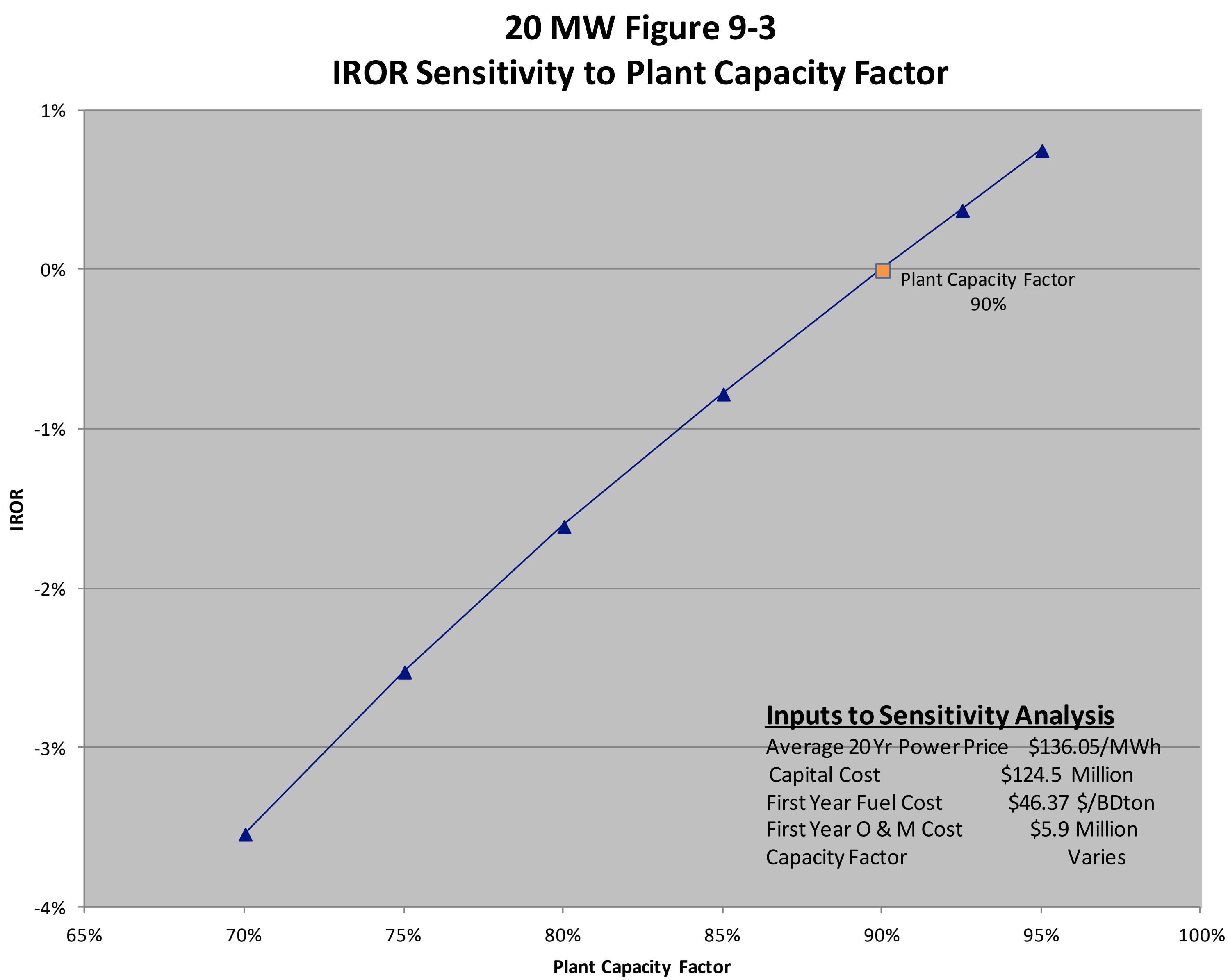
The effect of IROR relative to the breakeven point on various inputs to the model is summarized in 20 MW Figures 9-1 through 9-5.

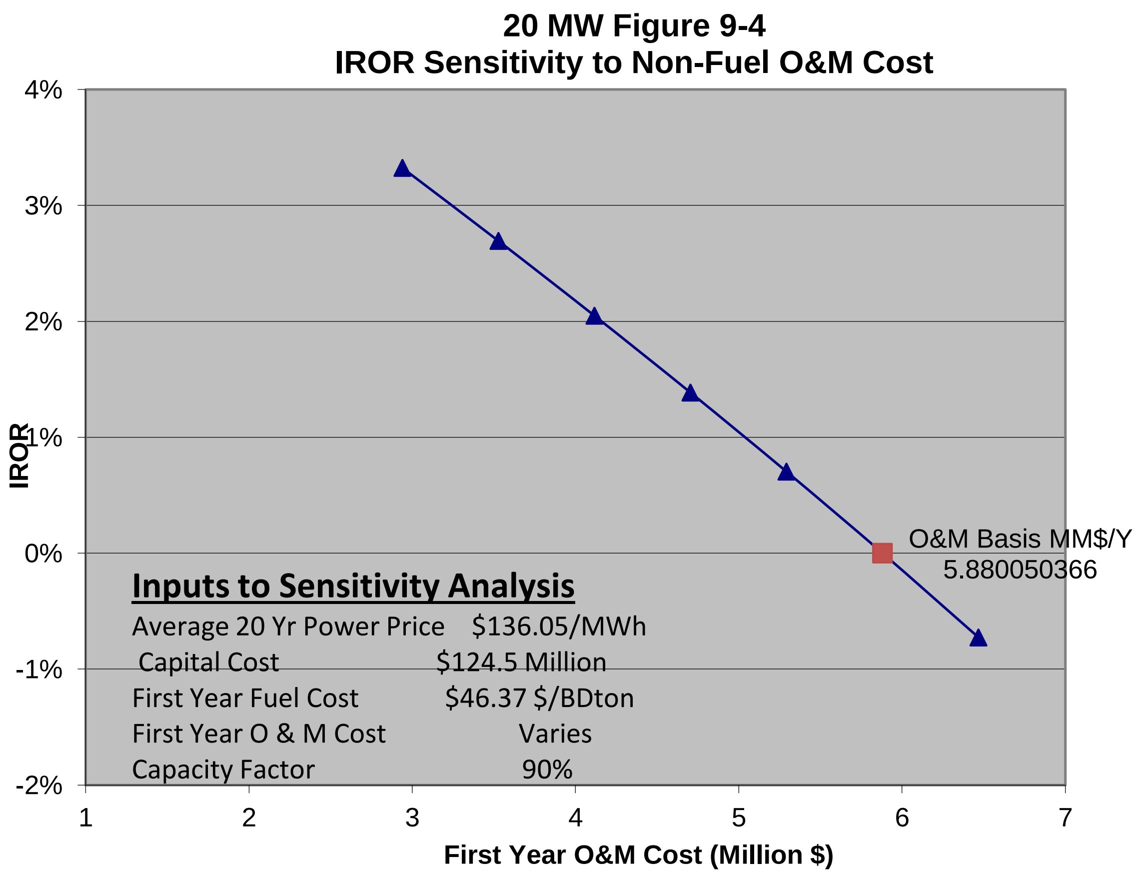
All sensitivities in 20 MW Figures 9-2 through 9-5 are based on an inflated power price of $136/MWhr. This is the IROR breakeven point as shown in 20 MW Figure 9-1. This price was selected to provide a better representation of the other project cost impacts to IROR.

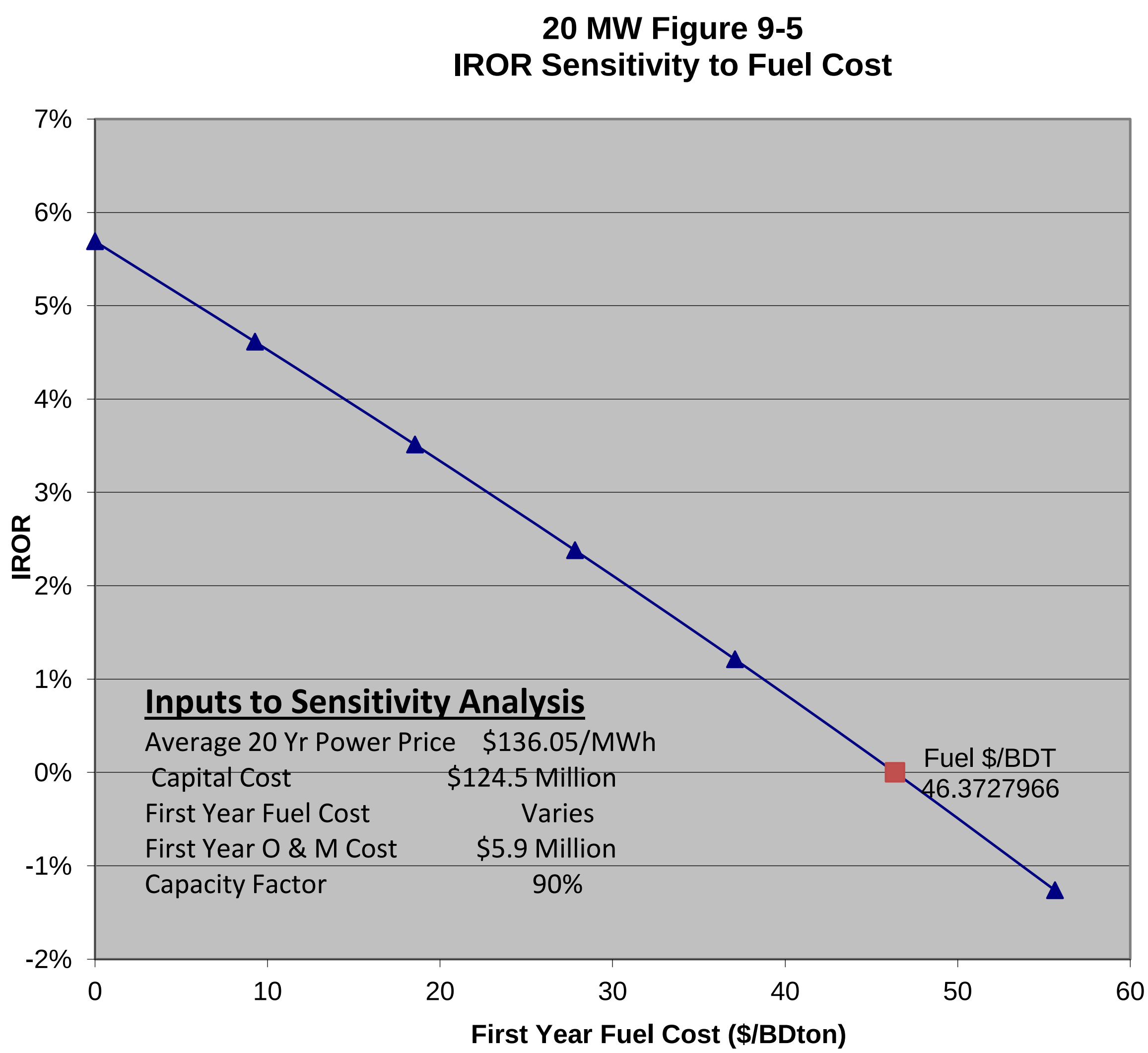
The sensitivity analyses are an important tool to stress test economics of any project. The negative cash flows shown above are a consistent indicator that with or without an analysis based on the break even point it is clear that a 20 MW project does not generate enough cash to cover the basic operating expenses which are dominated by the fuel cost.


20 MW Figure 9-1
IROR vs 20 Year Average Power Price
Inputs to Sensitivity Analysis
Average 20 Yr Power Price Varies
Capital Cost $124.5 Million
First Year Fuel Cost $46.37 $/BDton
First Year O&M Cost $5.9 Million
Capacity Factor 90%
MAR
0.17958 $/kWh
6.00%
Breakeven Average Elect Rate, 0.13605 $/kWh
EKI Predicted 20 yr Average Power Price, 0.0635 $/kWh
25%
20%
15%
10%
5%
0%
-5%
-10%
-15%
-20%
-25%
$0.025
$0.045
$0.065
$0.085
$0.105
$0.125
$0.145
$0.165
$0.185
$0.205
Average Delivered Power Price ($/kWh)


20 MW Figure 9-2
IROR Sensitivity to Project Capital Cost
6%
5%
4%
3%
2%
1%
0%
-1%
-2%
-3%
Project Cost (Million $)
$124.5
Inputs to Sensitivity Analysis
Average 20 Yr Power Price $136.05/MHh
Capital Cost Varies
First Year Fuel Cost $46.37 $/BDton
First Year O & M Cost $5.9 Million
Capacity Factor 90%
$-
$20
$40
$60
$80
$100
$120
$140
$160
$180
Project Capital Cost (Million $)


20 MW Figure 9-3
IROR Sensitivity to Plant Capacity Factor
1%
0%
-1%
-2%
-3%
-4%
IROR
65%
70%
75%
80%
85%
90%
95%
100%
Plant Capacity Factor
Plant Capacity Factor
90%
Inputs to Sensitivity Analysis
Average 20 Yr Power Price $136.05/MWh
Capital Cost $124.5 Million
First Year Fuel Cost $46.37 $/BDton
First Year O & M Cost $5.9 Million
Capacity Factor Varies


20 MW Figure 9-4
IROR Sensitivity to Non-Fuel O&M Cost
IROR
4%
3%
2%
1%
0%
-1%
-2%
1
2
3
4
5
6
7
First Year O&M Cost (Million $)
O&M Basis MM$/Y
5.880050366
Inputs to Sensitivity Analysis
Average 20 Yr Power Price $136.05/MWh
Capital Cost $124.5 Million
First Year Fuel Cost $46.37 $/BDton
First Year O & M Cost Varies
Capacity Factor 90%


20 MW Figure 9-5
IROR Sensitivity to Fuel Cost
IROR
7%
6%
5%
4%
3%
2%
1%
0%
-1%
-2%
0
10
20
30
40
50
60
First Year Fuel Cost ($/BDton)
Inputs to Sensitivity Analysis
Average 20 Yr Power Price $136.05/MWh
Capital Cost $124.5 Million
First Year Fuel Cost Varies
First Year O & M Cost $5.9 Million
Capacity Factor 90%
Fuel $/BDT
46.3727966

9.3.5 Generation and Capacity Factor for the 5 MW Options

The financial model estimates full-year energy output to be 33,507 MWh throughout the term of the model. The net generating capacity is 4.25 MW, and, when applied on an average of 329 operating days per year, results in the annual energy output. The number of operating days used in the financial model assumes 14 days of planned outage and an additional 22 days for unplanned outages, or an overall capacity factor of 90%. We believe that the plant can achieve this operating level over the life of the Project, but it will be difficult to achieve in the first two years of operation. Table 5 MW Table 9-1 summarizes the net energy export plan for the Project included in the financial model.

5 MW Table 9-1
Net Energy Export

Parasitic and Capacity	
Gross Output MW	**5.0**
Less Parasitic Load, MW	(.750)
Net Output Before Capacity Factor, MW	4.25
Capacity Percentage	100%
Net Saleable Output MW per Hour	**4.25**
Net Operating Hours per Year	**7884**
Annual Energy Export MWh	**33,507**

We prepared an internal electrical load list within the equipment list. The internal load or parasitic load is that internal electrical demand that is consumed by the plant during operations. The net electrical output is the gross generating capacity less the internal load.

The internal load study was based on information from the preliminary design and budget quotations from equipment suppliers. It should be expected that, as the detailed design proceeds, electrical loads will be more definitive and will more accurately reflect the actual conditions. The estimate used represents an internal load of 15 percent of the maximum output. We would expect to see internal loads for a biomass plant of similar scope, size, and design to be 12 to 17 percent range.

9.3.6 Revenues

Revenues used in the financial model are shown in Table 5 MW Table 9-2.

5 MW Table 9-2
Projected Revenues

Revenue Source	$/MWh
Power Revenue Provided by EKI (first year)	$29.21
Average Power Revenue Over 20-Year Life	$68.05

The power revenue of $29.21 per MWh is the wholesale price expected to be received by EKI in the first year of operation. The rate has been escalated at 2% for the duration in the EKI model. EKI did a power market study to determine the most beneficial method of marketing the power produced at the facility. The analysis looked at the value of the energy including RECs, and COCs based on five markets. The highest average power price results by selling power into Washington State as a package. The financial model uses the annual average power price for the Washington REC case for each year resulting in the average price of $68.05 per MHh from 2018 through 2037 or 20 years. (EKI calculated an average of $71.88 per MWh over 21 years from 2018 through 2038.) A sensitivity analysis was run on the power price effect on IROR and is presented in 5MW Figure 9.1.

9.3.7 Expenses

Expenses for the Project comprise fuel costs, ash disposal, non-fuel-based O&M costs, and Owner's costs. The costs for woody biomass fuel per ton, as projected in the Woody Biomass Supply Study of July 2014, start at $48.63 per BDT for the full condensing case and $39.57 per BDT for the cogeneration case, based on the quantity of purchased fuel from the CSKT sources. The condensing case requires the purchase of 42,865 BDT per year, while the cogeneration case requires the purchase of 23,805 BDT per year and receives the addition 23,805 BDT from the steam host (sawmill). The additional fuel used by the cogeneration case is the result of exporting 10,000 lb/hr of steam to the sawmill in exchange for 50% of the fuel. The first-year fuel cost is escalated at a rate of 0.75 percent annually thereafter in both cases.

Operating expenses for O&M labor, non-labor repair and maintenance, insurance, property taxes, and legal and professional fees are based on the average of the last four years' actual annual costs for a 35 MW fluid bed boiler generating plant in Montana, scaled to fit the 5 MW biomass plant using reasonable scaling factors. See Section 8 of this report for more detail on O&M expenses. Total non-fuel production-related O&M expenses equate to approximately $102.22 per MWh. O&M labor was escalated at 2.25% per annum, while non-labor repair and maintenance, as well as miscellaneous other costs and G&A, was escalated at 1.5%.

Fuel usage projections in the financial model are consistent with the predicted performance that was provided by Hurst Boiler as part of its proposal. The Hurst proposal was based on a significantly smaller boiler size of 36,700 pounds of steam per hour that was solicited early in the study. The adjusted 5 MW gross boiler for the condensing boiler output of 50,000 pounds per hour (lb/hr) of steam, which supports the turbine/generator's output of 5,000 gross kW. The cogeneration boiler produces 55,700 lb/hr of steam to support the 5 MW of generation and the export steam demand. The Hurst boiler's 70% efficiency is assumed constant when scaling the quoted boiler to the larger boilers. This results in fuel input of 9.88 tons per hour of as-received fuel and 10.98 tons per hour, based on a 45 percent moisture content at MCR, respectfully, for the two options. A sensitivity case has been run for the plant fuel cost compared with the internal rate of return and is discussed later in this report and shown in 5 MW Figure 9-5 and 5 MW CHP Figure 9-5.

9.3.8 Financial Model Conclusions

Feedstock usage projections are consistent with the material balances and vendor equipment expected performance conditions.

The fuel costs shown in the financial model are consistent with the blended costs developed from the fuel availability study, but the moisture content can drive the quantity of fuel required. Moisture content can vary throughout the year.

The planned operation of 329 days per year should provide adequate allowance for the performance of normal required maintenance (planned outages), along with 22 days of unplanned outages. It is likely that, if maintained properly and staffed by knowledgeable and trained personnel, the plant can achieve this operating rate over the life of the Project.

We did not account for Project long-term financing in the model.

We have performed the financial analysis using the technical results from this study as inputs to the financial model, including capital costs, operating levels, fuel supply projections, and annual operating and maintenance and reasonable costs assumptions for a 5 MW biomass facility. **The financial model projects that Project revenues are insufficient to cover the operating costs for the plant and will not provide a return on the investment.** A breakeven evaluation is provided in the sensitivity analysis portion of this section.

9.3.9 Sensitivity Analysis

Due to uncertainties inherent in relying upon assumptions and projections, it should be anticipated that actual operating results could differ, from those conditions assumed and described herein. We have prepared five sensitivity cases, as presented in 5 MW Table 9-3 and 5 MW CHP Table 9-3, which demonstrate the impact of certain circumstances on the financial model results. Sensitivity cases presented herein are intended to reflect the range of impact on the accuracy of the assumptions and estimates on the project.

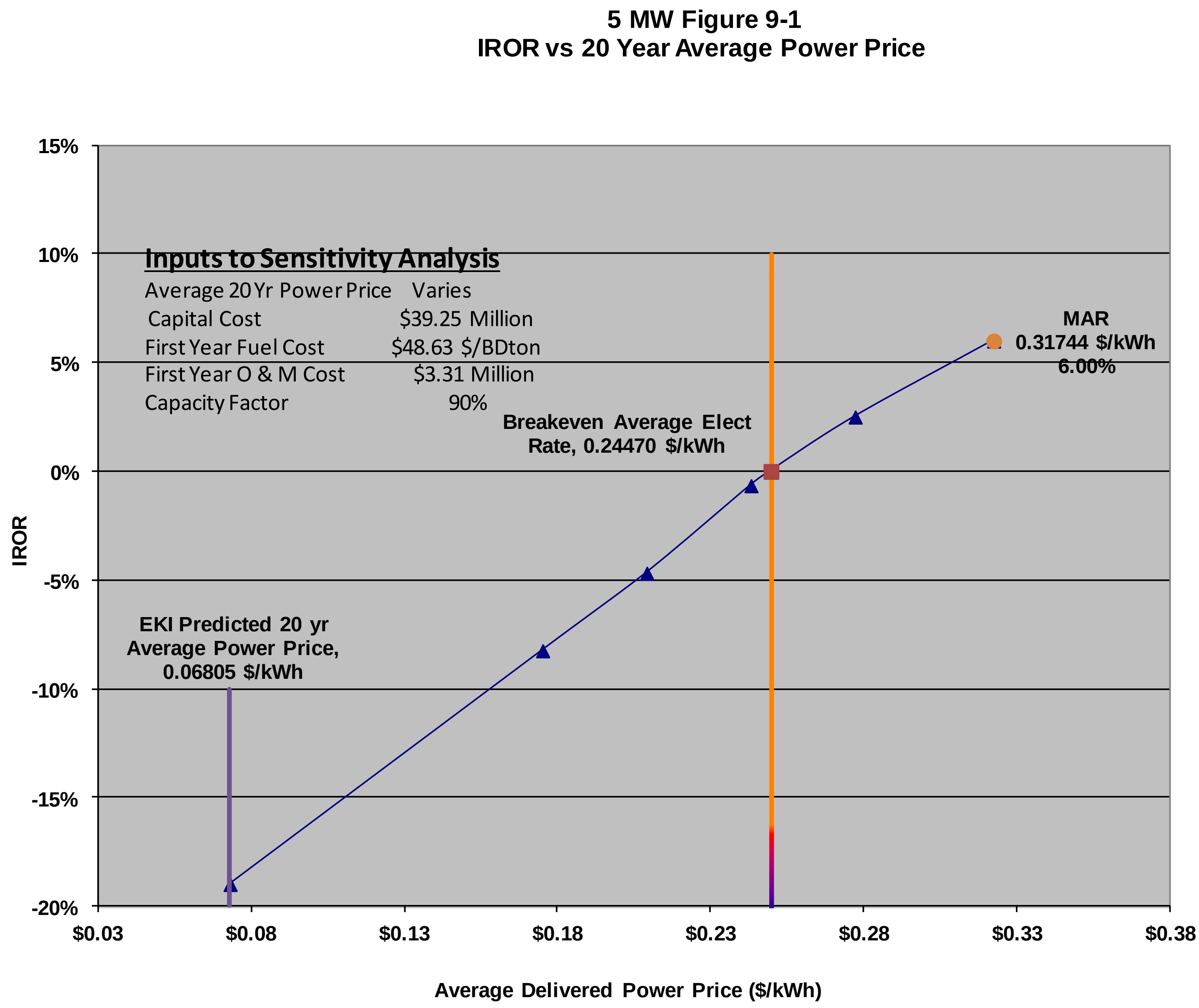
5 MW Table 9-3
Sensitivity Analysis

Sensitivity	**First-Year Cash Flow/IROR**	**20th-Year Cash Flow**
Base Case	$-4,529,959/ **NA**	$2,780,231
Breakeven Power Revenue (BPR) 3.6x Modeled	$-1,989,196/ **0.0%**	$8,293,481
Power Revenue at 4.66 x Modeled Values	$-943,123/ **6.00%**	$12,852,706
Capital Cost at 70% of Estimate @ BPR	$-1,989,196/ **2.08%**	$8,293,481
Fixed O&M Costs at 70% @ BPR	$-995,483/ **3.23%**	$9,642,016
Fuel Cost at 70% @ BPR	$-1,363,,897/ **1.92%**	$9,014,163
80% Plant Capacity Factor @ BPR	$-2,142,660/ **-2.09%**	$6,863,975

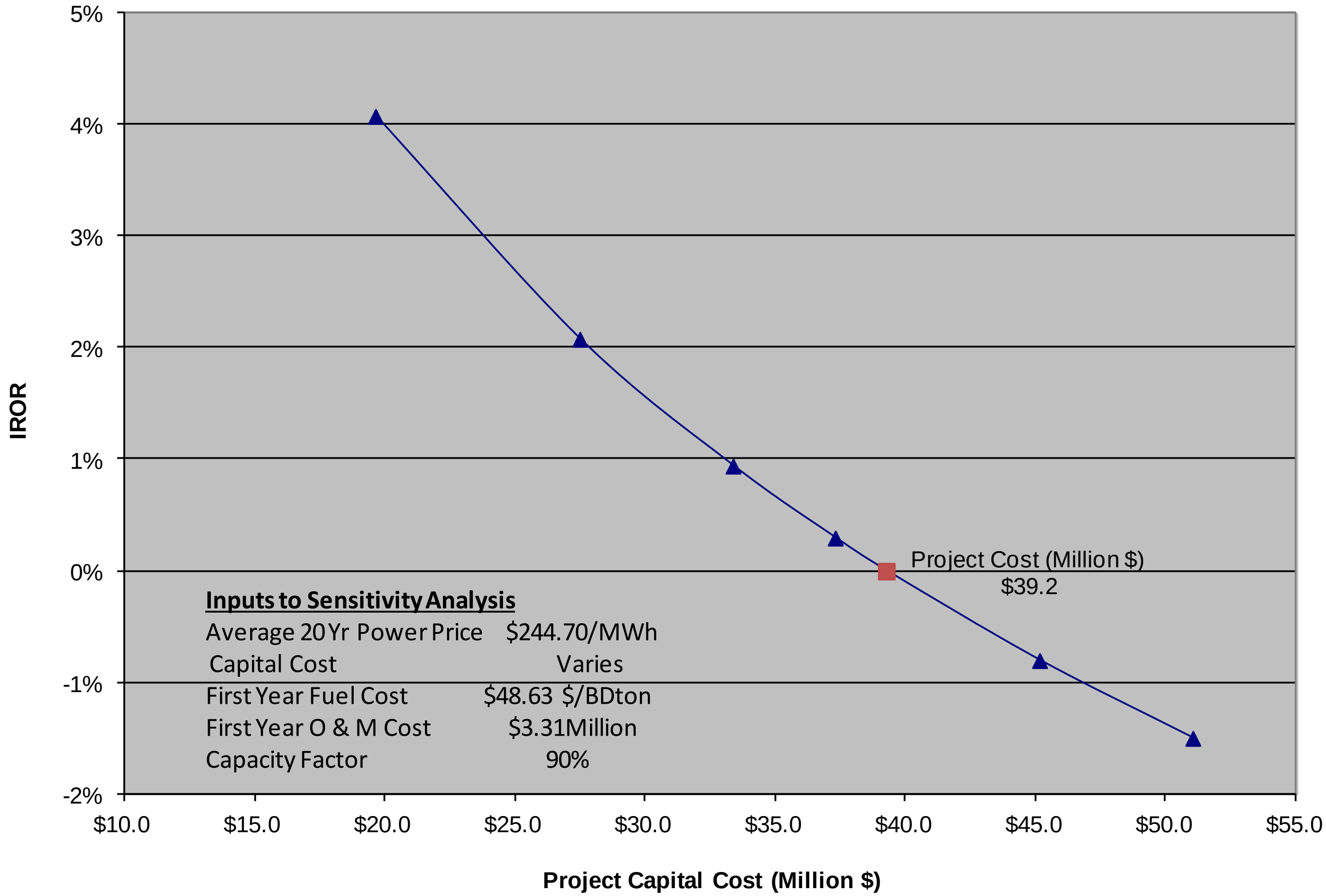
The effect of IROR relative to the breakeven point on various inputs to the model is summarized in Figures 5 MW 9-1 through 9-5.

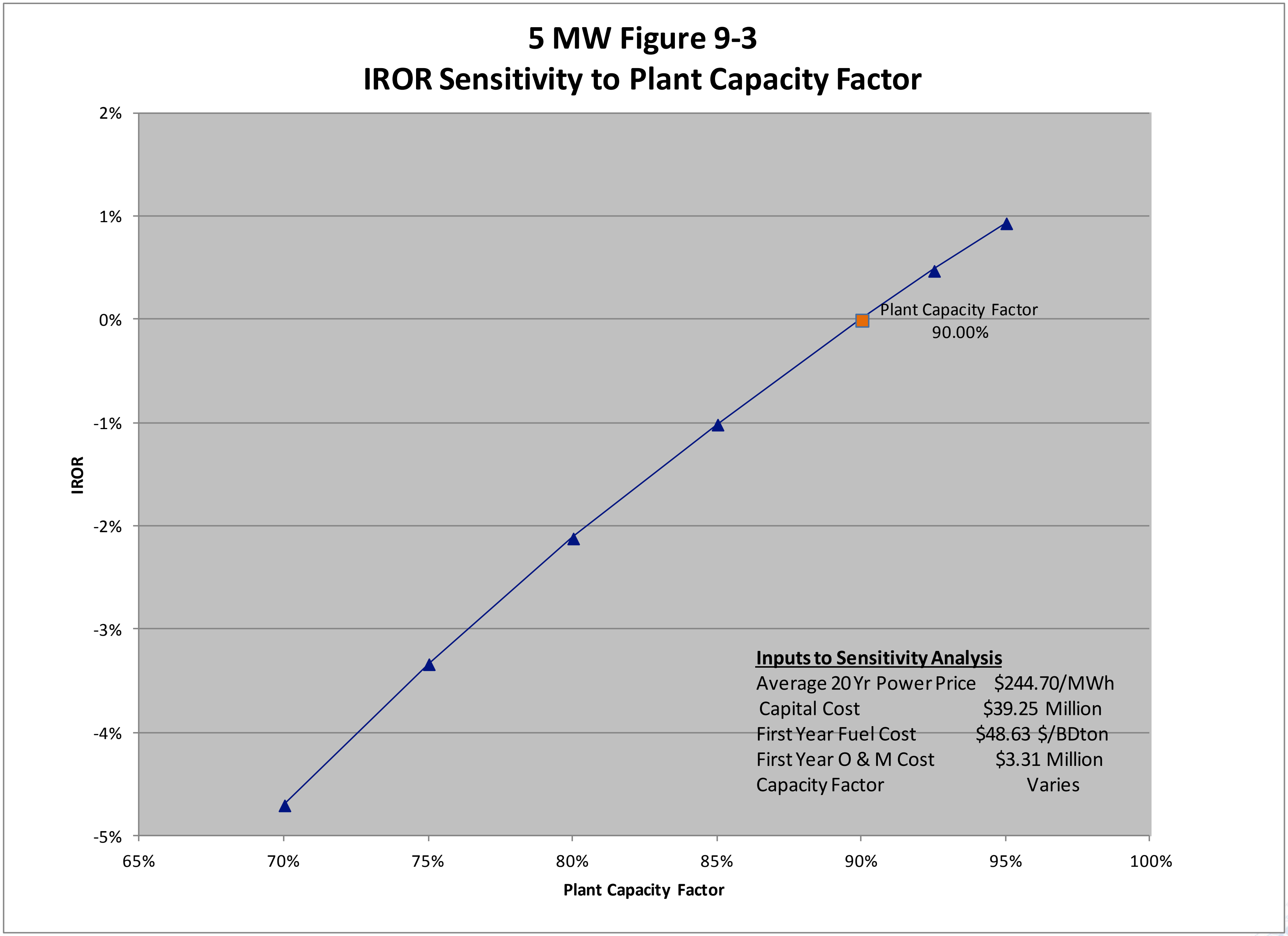
All sensitivities in the 5 MW Figures 9-2 through 9-5 are based on an inflated power price of $245/MWhr. This is the IROR breakeven point as shown in the 5 MW Figure 9-1. This price was selected to provide a better representation of the other project cost impacts to IROR.

Similar the 20 MW case the 5 MW case does not generate sufficient cash to cover the operating expenses. The 5 MW case is more significantly impacted by the lack of any economy of scale compared to the 20 MW case.

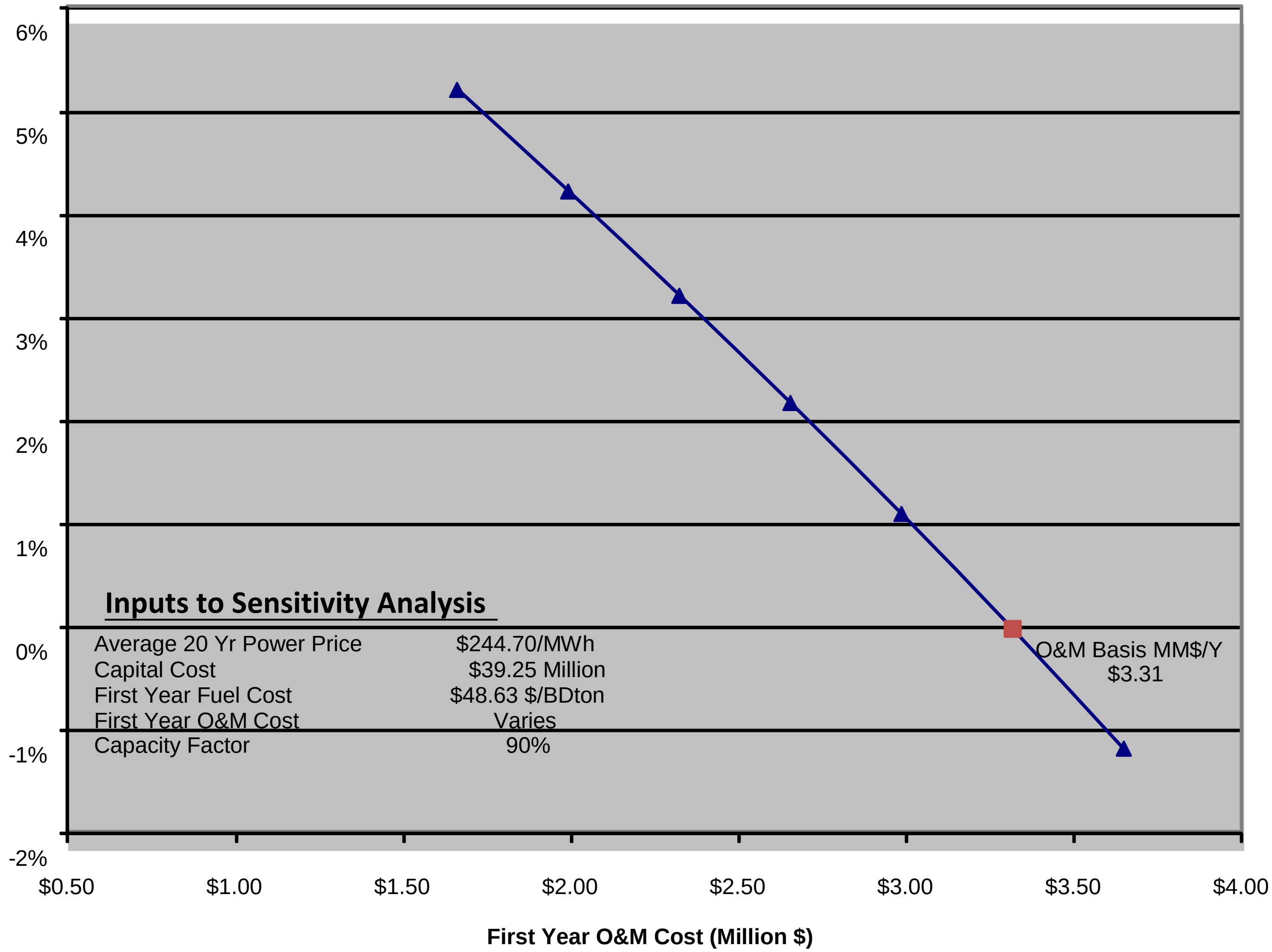

5 MW Figure 9-1
IROR vs 20 Year Average Power Price
Inputs to Sensitivity Analysis
Average 20 Yr Power Price Varies
Capital Cost $39.25 Million
First Year Fuel Cost $48.63 $/BDton
First Year O & M Cost $3.31 Million
Capacity Factor 90%
Breakeven Average Elect Rate, 0.24470 $/kWh
MAR 0.31744 $/kWh 6.00%
EKI Predicted 20 yr Average Power Price, 0.06805 $/kWh
15%
10%
5%
0%
-5%
-10%
-15%
-20%
IROR
$0.03
$0.08
$0.13
$0.18
$0.23
$0.28
$0.33
$0.38
Average Delivered Power Price ($/kWh)

5 MW Figure 9-2
IROR Sensitivity to Project Capital Cost

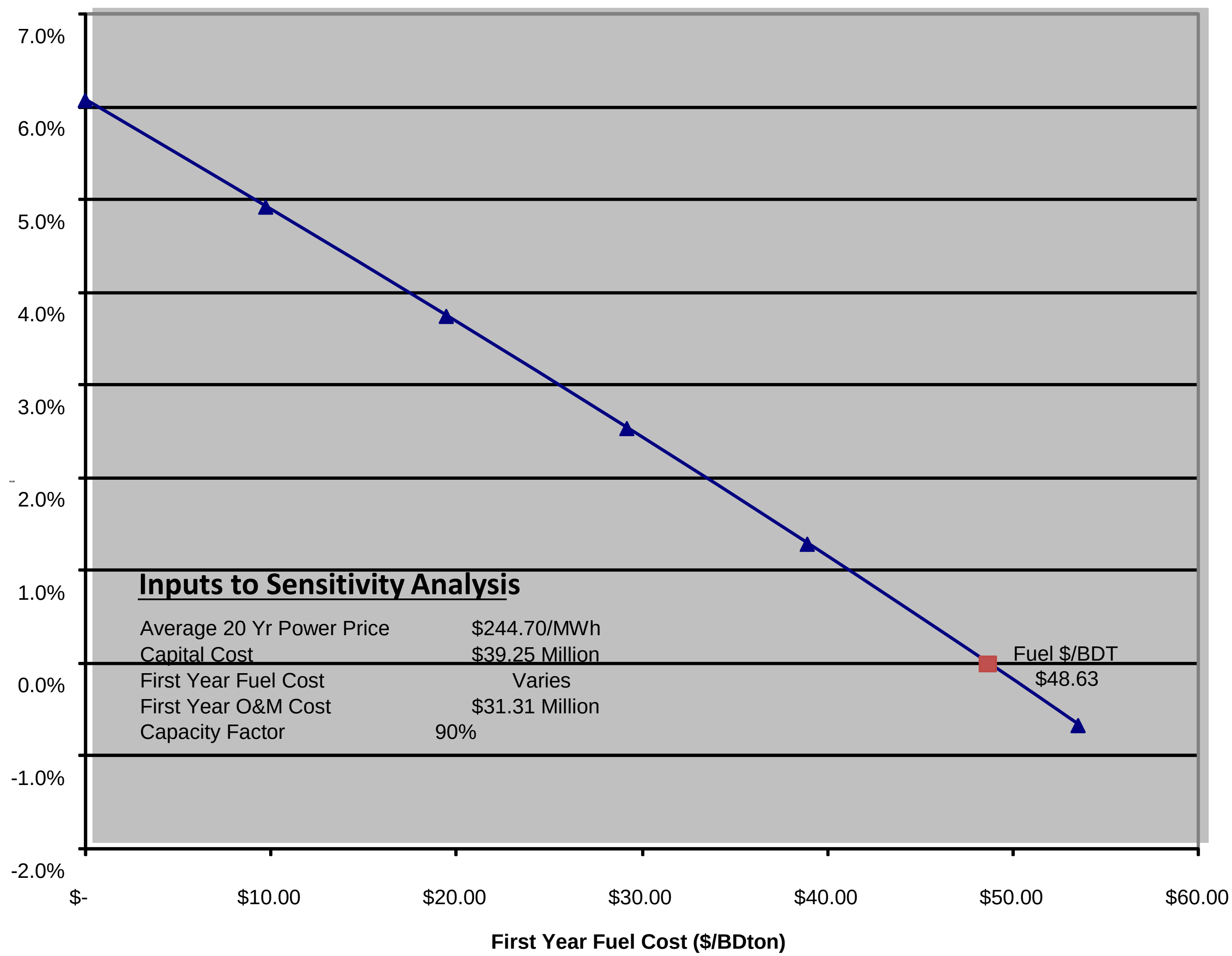



5 MW Figure 9-3
IROR Sensitivity to Plant Capacity Factor
2%
1%
0%
-1%
-2%
-3%
-4%
-5%
IROR
Plant Capacity Factor
90.00%
Inputs to Sensitivity Analysis
Average 20 Yr Power Price $244.70/MWh
Capital Cost $39.25 Million
First Year Fuel Cost $48.63 $/BDton
First Year O & M Cost $3.31 Million
Capacity Factor Varies
65%
70%
75%
80%
85%
90%
95%
100%
Plant Capacity Factor

5 MW Figure 9-4
IROR Sensitivity to Non-Fuel O&M Cost



5 MW Figure 9-5
IROR Sensitivity to Fuel Cost



9.4 5 MW CHP SENSITIVITY ANALYSIS

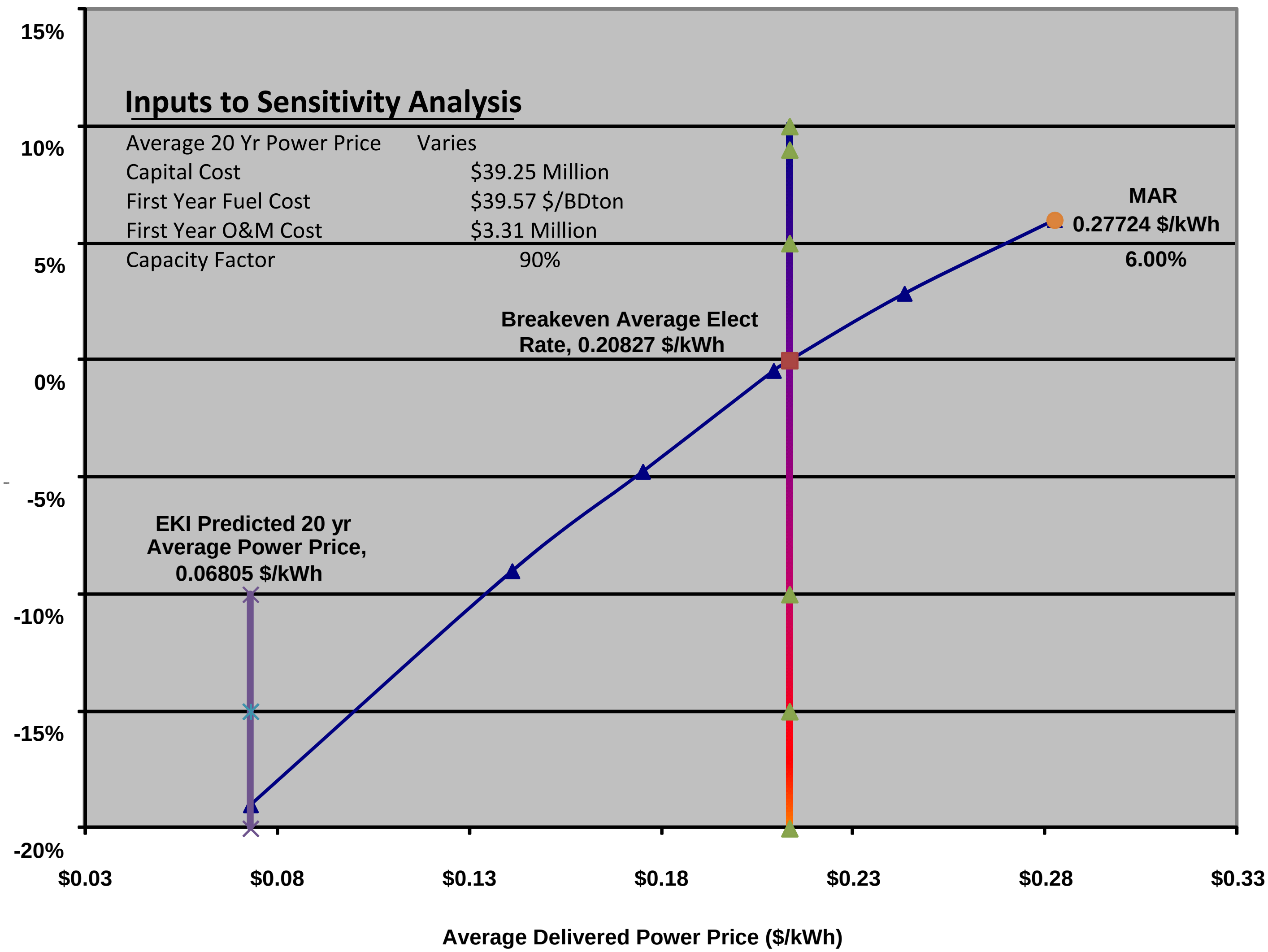
5 MW CHP Table 9-3
Sensitivity Analysis

Sensitivity	**First-Year Cash Flow/IROR**	**20th-Year Cash Flow**
Base Case	$-3,393,509/ **NA**	$ - $1,471,472
Breakeven Power Revenue(BPR) 3.06x Modeled	$-1,376,706/ **0.0%**	$7,318,597
Power Revenue at 4.07 x Modeled Values	$-384,792/ **6.00%**	$11,641,776
Capital Cost at 70% of Estimate @ BPR	$-1,376,706/ **2.24%**	$7,318,597
Fixed O&M Costs at 70% @ BPR	$-382,994/ **3.41%**	$8,667,132
Fuel Cost at 70% @ BPR	$-1,094,143/ **0.94%**	$7,644,262
80% Plant Capacity Factor @ BPR	$-1,597,892/ **-2.23%**	$5,997,853

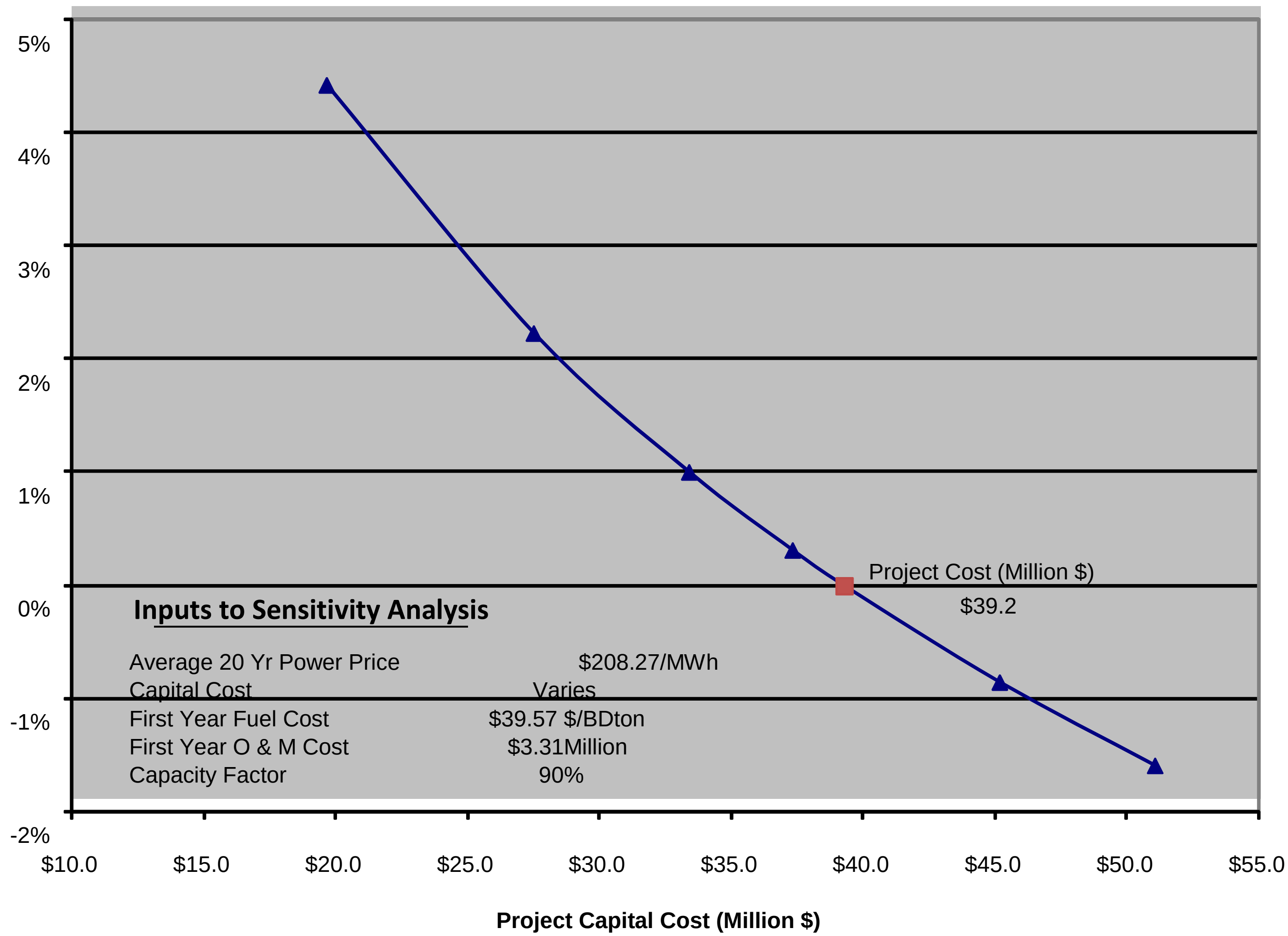
The effect of IROR relative to the breakeven point on various inputs to the model are summarized in Figures 5 MW CHP 9-1 through 9-5.

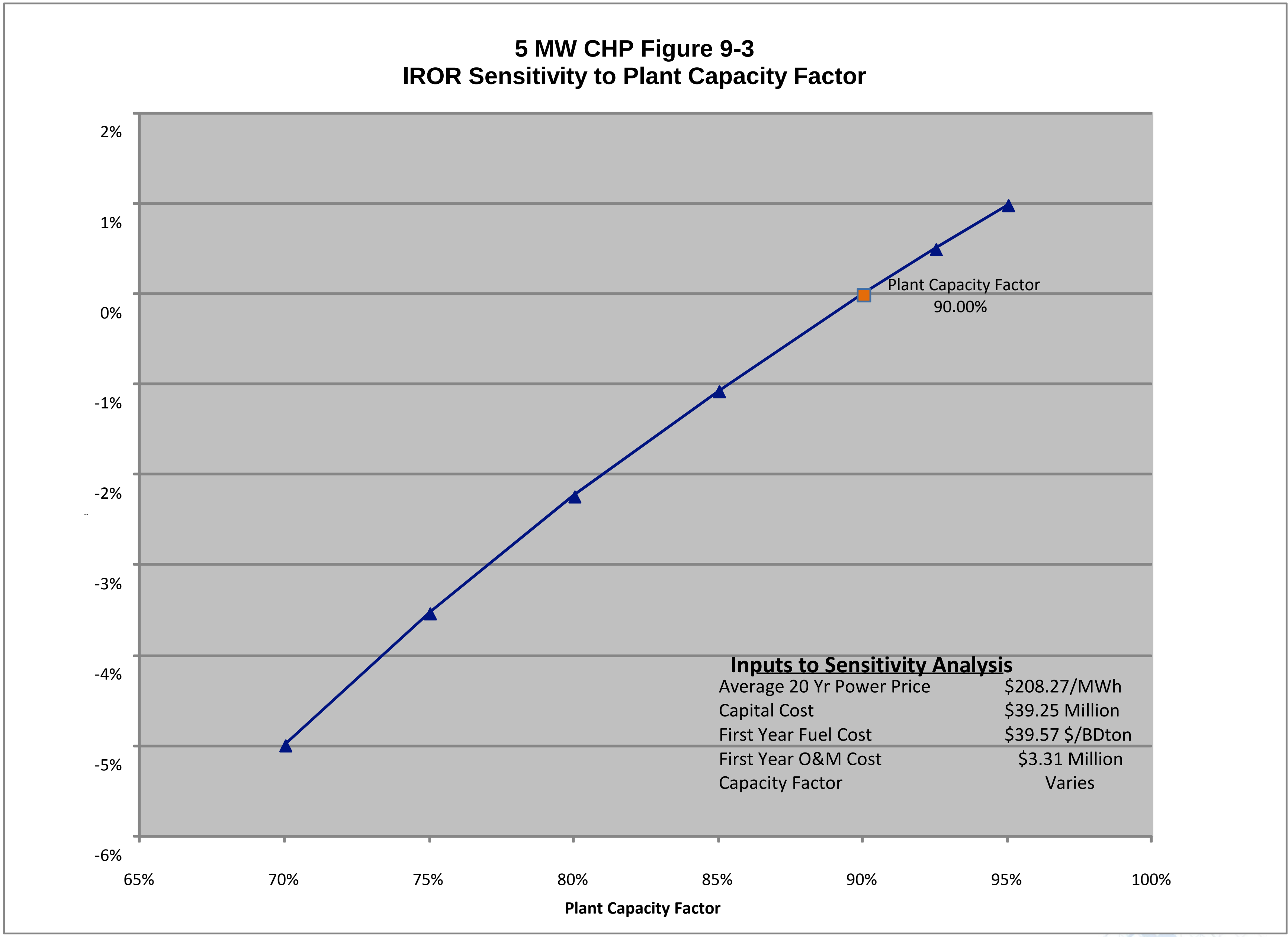
All sensitivities in the 5 MW CHP Figures 9-2 through 9-5 are based on an inflated power price of $208/MWhr. This is the IROR breakeven point as shown in the 5 MW CHP Figure 9-1. This price was selected to provide a better representation of the other project cost impacts to IROR.

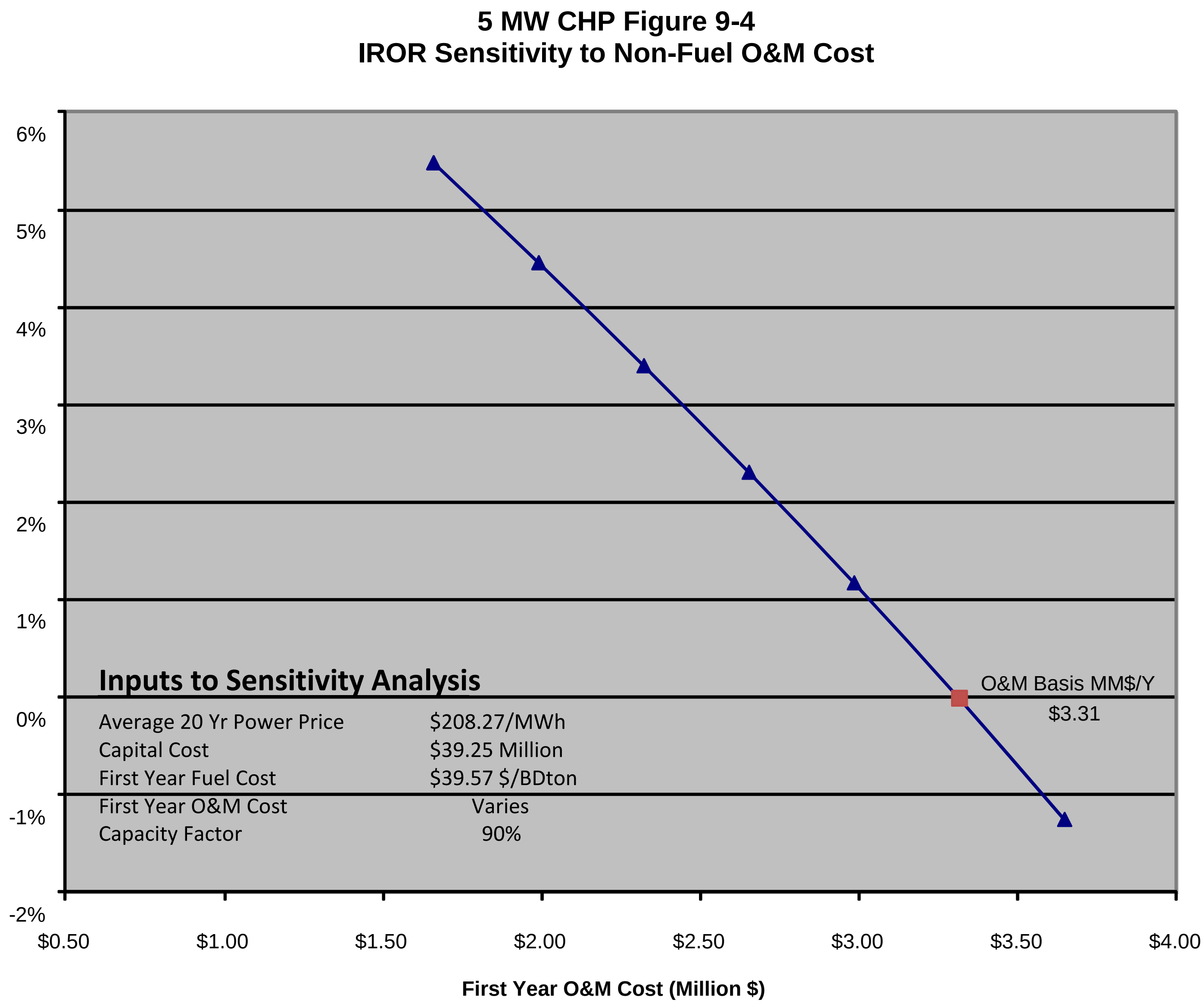
5 MW CHP Figure 9-1
IROR vs 20 Year Average Power Price

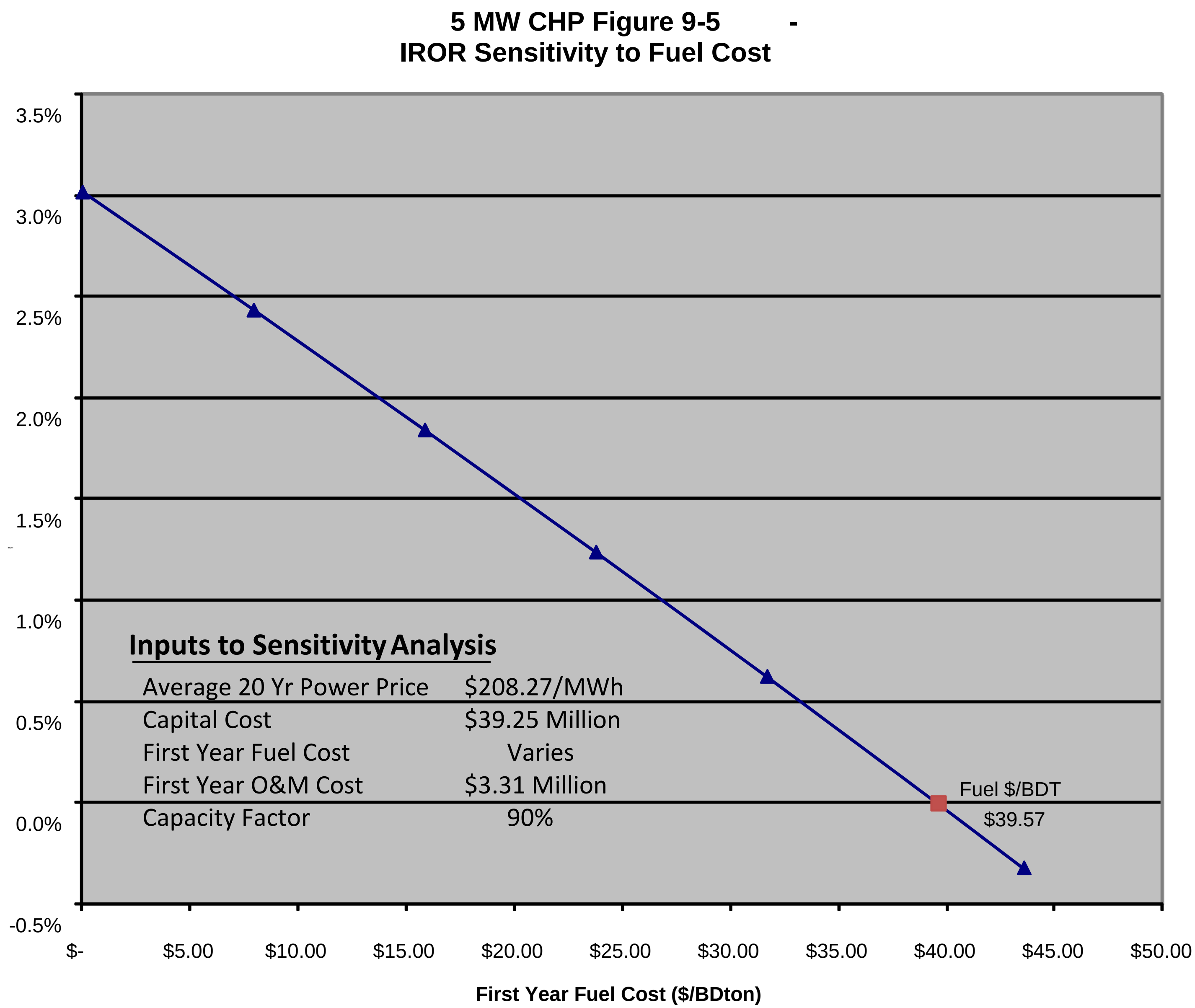


5 MW CHP Figure 9-2
IROR Sensitivity to Project Capital Cost




5 MW CHP Figure 9-3
IROR Sensitivity to Plant Capacity Factor
2%
1%
0%
-1%
-2%
-3%
-4%
-5%
-6%
65%
70%
75%
80%
85%
90%
95%
100%
Plant Capacity Factor
Plant Capacity Factor
90.00%
Inputs to Sensitivity Analysis
Average 20 Yr Power Price $208.27/MWh
Capital Cost $39.25 Million
First Year Fuel Cost $39.57 $/BDton
First Year O&M Cost $3.31 Million
Capacity Factor Varies


5 MW CHP Figure 9-4
IROR Sensitivity to Non-Fuel O&M Cost
6%
5%
4%
3%
2%
1%
0%
-1%
-2%
Inputs to Sensitivity Analysis
Average 20 Yr Power Price $208.27/MWh
Capital Cost $39.25 Million
First Year Fuel Cost $39.57 $/BDton
First Year O&M Cost Varies
Capacity Factor 90%
O&M Basis MM$/Y
$3.31
$0.50
$1.00
$1.50
$2.00
$2.50
$3.00
$3.50
$4.00
First Year O&M Cost (Million $)



5 MW CHP Figure 9-5 -
IROR Sensitivity to Fuel Cost
3.5%
3.0%
2.5%
2.0%
1.5%
1.0%
0.5%
0.0%
-0.5%
Inputs to Sensitivity Analysis
Average 20 Yr Power Price $208.27/MWh
Capital Cost $39.25 Million
First Year Fuel Cost Varies
First Year O&M Cost $3.31 Million
Capacity Factor 90%
Fuel $/BDT
$39.57
$-
$5.00
$10.00
$15.00
$20.00
$25.00
$30.00
$35.00
$40.00
$45.00
$50.00
First Year Fuel Cost ($/BDton)

9.5 ECONOMIC ANALYSIS – SUMMARY

9.5.1 20 MW Plant

In order for the project to have a non-leveraged IROR of 0% (breakeven), the average value of power sales needs to equal $136 per MWh.

9.5.2 5 MW Full Condensing Plant

In order for the project to have a non-leveraged IROR of 0% (breakeven), the average value of power sales needs to equal $245 per MWh.

9.5.3 5 MW CHP Plant

In order for the project to have a non-leveraged IROR of 0% (breakeven), the average value of power sales needs to equal $208 per MWh.

At the outset of the study, it was thought that:

1. Economy of scale of a 20 MW plant would support a positive IROR. Due to the low market value of power, this is not economically feasible.

2. A small plant with a steam host would offset the economy of scale challenge through the benefit of steam host revenues, but, again, due to the low market value of power, this option is not economically feasible, either.

The Project appears to be more sensitive to the O&M cost than to the other parameters. This is especially true for the 5 MW options, as labor constitutes a higher portion of the non-fuel O&M, as compared to the 20 MW plant.

Appendices

A 3.5 & 5 MW Equipment Quotes

B 20 MW Equipment Quotes

C Gasifier Quotes

D Heat Balances and Flow Sheets

E Electrical and Controls

F Export Pipelines

G Site Information and Arrangements

H 30% Design Review

I 60% Design Review

J BECK-Woody Biomass Supply Study

K CSKT Facility Energy Study

L Capital Cost Estimates

M Budgetary Financing Analysis