ENERGY ANALYSIS DESIGN REPORT
SECONDARY SALES ELECTRIC BOILER
WHITEHORSE GENERAL HOSPITAL
WHITEHORSE, YT

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1.0 Introduction

In the past the traditional fuel source for large healthcare facilities in the Canadian north has been fuel oil. As a fuel source, diesel and heating fuel have the benefits of easy shipping, good low temperature handling characteristics and relatively low cost on a unit energy basis.

Recently, electrical demand in the Yukon has been dramatically reduced with surplus low cost hydroelectric power becoming available in various parts of the Yukon, and most specifically the Whitehorse area. With the availability of the low cost hydroelectric power supplied on a secondary sales basis the viability of the traditional fuel oil system as a prime energy source is no longer assured.

Based on the availability of the low cost hydroelectric energy FSC was commissioned in the fall of 2001 to prepare a preliminary Secondary Sales Feasibility Study for the Whitehorse General Hospital. This preliminary study was to review the general viability of secondary sales to the Whitehorse General Hospital and the associated renovations and costs providing a summary of the following information:

- Monthly forecasts on energy consumption and cost for the WGH and simple payback analysis of secondary sales electrical energy vs. fuel oil.
- System options for secondary sales including system modifications, costs, block diagrams, outlines of capital works and capital works schedules.

For complete details of this report it is recommended that readers obtain a copy for review. To allow general background information a copy of the executive summary is appended in Appendix A of this report. In general, however, the Feasibility Study showed excellent viability for a secondary sales system. This viability was proven for new electric low-pressure steam boiler (s) to operate in parallel with the existing fuel fired boilers with simple paybacks on initial capital expenditures varying between 3 to 7 years depending upon fuel costs and final boiler sizing.

As a result of the positive findings of the Feasibility Study, the Energy Solutions Center in conjunction with the Whitehorse General Hospital and Yukon Energy Corporation have advanced the project to the design and construction stage to implement what will be one of the largest secondary sales projects in the Yukon Territory. This report is the first deliverable for this project.

While excellent viability was proven in the feasibility study, the modeling tool of degree-day analysis was a relatively crude tool. Given the high initial capital expenditures to initial this project ($600k-1991) it was recommended that prior to initiating the actual capital works a more detailed model be completed to verify the feasibility study. This Energy Analysis design report is the deliverable for this more detailed model and evaluation.

2.0 Existing Facility Background

The Whitehorse General Hospital is a 49-bed acute care facility completed in approximately 1995. This facility is comprised of about 7150m2 of new building joined to 3865m2 of old renovated hospital. Basements and service spaces are approximately 8063m2. Total building area is 19051m2.

In addition to the hospital loads the Energy Center for the hospital also provides building and service water heating to the adjacent Thompson Center. This long-term care facility is a single storey building of 3658m2 with a full heated crawlspace and basement.

The hospital layout is programmed over two floors with the existing renovated hospital and the new building linked by an enclosed and heated atrium. Administration, outpatients and offices have been located in the old renovated hospital. The new building houses the main patient care functions including the wards, OR and procedures. Housekeeping and Nutrition are also located within the new building with the physical plant located in a separate attached Energy Center to the north of the main buildings.

The Thompson Building is linked to the south end of the hospital with heating services provided through a service utilidor.

Mechanical

The facility HVAC and mechanical systems are similar to those found in acute care hospitals and long term care facilities in other cold climate regions. Three fuel oil fired low-pressure steam (LPS) boilers provide building heating and service heat for humidification, DHW and service hot water heating and LPS for kitchen appliances. For building heating, steam/water and steam/glycol converters located in the boiler room and Thompson Building basement are used to convert the LPS to hydronic heating. The water circuits are used for all building heating. The glycol circuits for the ventilation system air-processing unit (APU) preheat and reheat.

Seven APU and two AHU (smaller fan coil units) provide ventilation for the hospital. APU 1 and 2 are the main units for the treatment areas. The units operate in parallel and are provided with energy wheel heat recovery. APU 3 provides ventilation to the lower tech treatment areas and general spaces. APU 4 and 5 are 100% redundant units that provide ventilation to the general spaces and areas of refuge. APU 1 thru 5 all operate on 100% outdoor air and are located in the new fan mezzanine. APU 6 and 7 are located in the renovated hospital mezzanine and are re-circulating units with return fans. APU 6 provides ventilation to the offices while APU7 to the atrium.

The two smaller AHU’s are located in the hospital Ambulance Bay (AHU1) and the Energy Center (AHU 2). AHU 1 provides ventilation for control of CO/NOx in the Ambulance Bay. AHU 2 provides cooling and combustion air for boiler operation in the Energy Center.

In the Thompson Building a total of 5 main AHU provide ventilation the Central and North and South wings of the building. In addition three service units provide ventilation to the two basement mechanical rooms and crawlspace.

LPS for humidification is provided direct from the main LPS system. Steam grid humidifiers located on all the APU provide primary humidity control. In addition local control by duct mounted steam grids provides supplementary humidification for high load critical zones.

Four storage tanks in the Hospital and two in the Thompson Center with tankless heaters provide 82degC service hot water and 60degC domestic hot water in the hospital. An independent high-pressure steam system with two oil-fired boilers provides HPS for sterilization in the Hospital

Medical gas systems, specialty medical mechanical systems, fire protection systems and fuel systems have not been reviewed as a component of this project.

Electrical

Electrical services for the Whitehorse General hospital are routed to the building underground from a utility-owned pad-mounted transformer located southwest of the Energy Center. From the 12.5kV utility distribution system, primary cabling and ducting is routed underground to the transformer pad location where the service voltage is transformed to 600V, 3 phase, 4-wire before entering the building.

The main switchgear includes a 2000 Amp main breaker that subsequently feeds a 2400 Amp bus within the switchgear. From two locations in the switchgear, 1200A breakers are used to sub-feed two distribution centers, Bus #1 and Bus #2, with Bus #1 configured as the emergency distribution bus. A single 850 kW generator feeds Bus #1 via a transfer switch that includes a second 1200A breaker. There is also a separate 100A breaker connected directly from the generator output to the fire pump transfer switch that is sourced from the non-emergency Bus #2. The main switchgear is located on the mezzanine level of the Energy Center above, but in close proximity to, the generator that is located on the lower level of the mezzanine.

The existing LPS boiler loads are sourced from two different MCC's with Boilers 2 and 3 on MCC-EC-E1 (emergency power) and Boiler 1 on MCC-EC-1 (normal power only).

3.0 Energy Modeling

New DOE2.1e Model

The purpose of this Energy Analysis was to confirm the findings of the Feasibility Study completed in fall 1991 using degree-day analysis. To verify these results a higher accuracy model for energy performance was to be used. To complete this work the DOE2.1e modeling tool was selected. This program is the premier 8760hr-modeling tool currently in use in North America. In essence this program allows designers to accurately model energy consumption in a building on an hourly basis accurately accounting for both internal and external gains and losses.

Enersys Analytics who specialize in energy modeling building science, load research, and customized energy information systems provided development of the energy performance model. Initially Enersys Analytics completed the model for the Whitehorse Hospital only. During preliminary review meetings the design committee indicated the Thompson Building had not been included in the model. At this time it also became evident that in fact the Thompson Building had also not been included in the Feasibility Study. To rectify this error the DOE2.1e model and applicable degree-day models were updated to include the Thompson Building.

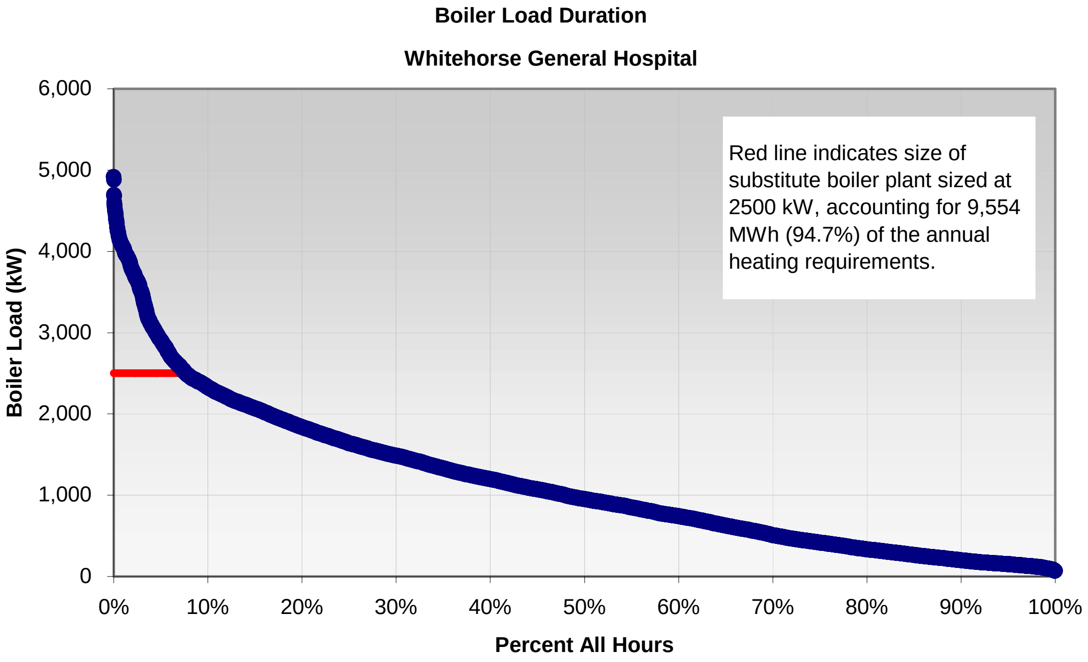
To develop the energy performance simulation first required translating the building information into a baseline DOE2 model. This included describing the building geometry and shell components, the interior space conditions for lighting, equipment, people, process loads, etc., and the mechanical HVAC and DHW systems which serve the two buildings. Since not all inputs can be perfectly known, several assumptions had to be made. The most significant of these assumptions typically resides in the schedules. But other characteristics such as the true amount of outdoor air, the DHW load, the boiler part-load operation, minimum fan configuration settings, and cooking and process loads all can all have a significant impact on the heating load and overall fuel oil consumption.

To reduce the potential error inherent in the assumed inputs the developed model was correlated to correspond with the historic electrical and fuel oil billing. In this case the average calendar-normalized fuel oil consumption for summer-1998 through summer-2000, and the average calendar-normalized electrical energy use (demand was not provided) for summer-1997 through summer-2001 were used, as this data was the basis for the 2001 Feasibility Study models. By using this modeling technique excellent correlation on the fuel oil energy was obtained. Correlation on the electrical consumption, was however, more difficult. The actual electrical energy consumption was typically lower than the uncorrelated values requiring an improvement on the fan power, lighting and equipment load characteristics to match the lower historic consumption.

More advanced details of the results of the DOE2.1e model are provided in Appendix B, along with summaries provided by Enersys Analytics. Included are "Baseline Calibration" files that show the final differences between the developed model and the calibration to historic consumption and the Energy Simulation results showing annual energy breakdowns and costs. These are provided for the Hospital without the Thompson Center (for reference purposes only) and for the integrated Hospital and Thompson Center, which are the outputs applicable to this evaluation.

Using this technique annual energy requirements for the buildings were estimated at 10 100 MWh with a fuel consumption of 1 475 900 L or 16 000 MWh input. This results in a seasonal plant efficiency of 63%. Using a fuel oil cost of $0.45/L annual fuel oil costs are set at $664 000 per year. More advanced details including charted energy breakdowns and electrical energy consumption and costs are provided in Appendix B. (Note that the costs listed in Appendix B are based on $0.40/L for FO and 0.125/kWh and $11.53/kW demand charge for electrical energy.)

Also generated as a component of this model were boiler load duration curves. These curves show the boiler load vs. percentage of all hours and percentage of load hours. These outputs are most important for this study as they allow accurate selection of the optimum secondary sales boiler capacity.



Red line indicates size of substitute boiler plant sized at 2500 kW, accounting for 9,554 MWh (94.7%) of the annual heating requirements.

Fig 3.1 Load Duration Curve-Boiler kW

The curves for the correlated model are shown in Figures 3.1 and 3.1. Both curves show a relatively flat duration curve until approximately 10% of total hours. At this time the load curves exhibit a rapid change in slope to meet the peak coincidental demands. This is relatively typical for heating plant applications with large weather dependent loads such as building heating. In addition to these curves the peak coincidental heating load was also generated from the correlated model at 4920kW. This is scheduled on Jan 9, 1800hrs with a design temperature of –48.9degC.

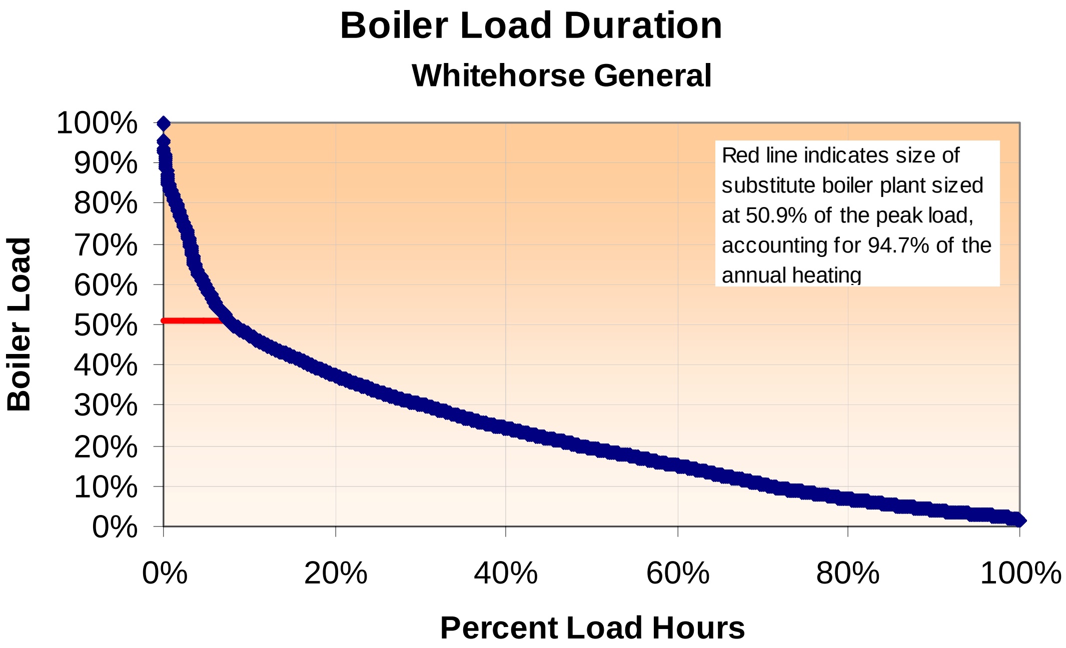


Fig 3.2 Load Duration Curve-Percent Boiler Load

Feasibility Study - DOE2.1e Model Comparisons

Direct comparison between the two studies would be difficult, as the 2001 Feasibility Study did not include for the Thompson Building. To allow comparison a rough upgrade of the 2001 Feasibility Study values has been completed. From the Feasibility Study only Option 3 has been evaluated, as Options 1 and 2 are either technically or financially not viable. Option 3 was to provide new secondary sales LPS boiler (s) located in the existing generator/co-generation room.

The 2001 Feasibility Study analyzed energy consumption and peak loads in two manners. The first was using historic fuel consumption and degree-day analysis to find the resultant peak coincidental load. Using this technique a peak-heating load of 6666kW was developed. This load was calculated using historic fuel oil input to the heating plant so the Thompson Building load was included in this calculation by default. This value was referenced as being high relative to the calculated connected loads since at that the time the model was developed the load of Thompson Building was unknown to the designers. As such this value was not used for further analysis in the 2001 Feasibility Study.

Now that is it understood that this value in fact represents reasonable building loads an analysis to the DOE2.1e model value is suitable. In comparison the coincidental peak-heating load using the correlated DOE2.1e model was found to be 4920kW. This is a difference of 26% to the 2001 Feasibility Study DD value of 6666kW, which is not surprising. The major problem with the historic degree-day model is its inability to account for non-weather based loads. Using the degree-day technique all loads are assumed to be weather based which is not a true representation for a hospital that has process based loads associated with laundry, cooking, and cleaning and infection control. To allow a more accurate comparison the fuel oil consumption generated by the DOE2.1e model for weather dependent heating was separated from the DOE2.1e model for the total heating. This resulted in the weather-based load accounting for only 78% of the total fuel consumed. If the annual fuel oil consumption is then reduced by 22% and the degree-day model recalculated the peak-heating load for weather dependent loads is then estimated at 5200kW.

To allow a direct comparison between models, however, the heating load for non-weather loads must be added back to the DD weather related peak loads. To accomplish this the average load of 26 517L of fuel oil per year for washing, service hot water and cooking are added by calculating the average heating load using the annual boiler efficiency of 63%. This corresponds to an average heating load of 248kW for a total peak-heating load using an adjusted degree-day model of 5448kW. Thus using this corrected data results in a difference of only 10% between the correlated DOE2.1e and the adjusted 2001 Feasibility Study DD models showing excellent correlation between the two models.

As discussed at the time of 2001 Feasibility Study the historic DD analysis could not anticipate the weather-independent building heating loads. To allow a more accurate estimate of typical building energy consumption the 2001 Feasibility Study used a different approach to calculate the building loads and the resulting annual energy loads. To accomplish this for the Hospital the theoretical heating loads were calculated or obtained from the design drawings.

The calculated heating loads from the 2001 Feasibility Study were summarized as follows:

Description/System		**System**		**Load**
		LPS	**HPS**	**(kW)**
Building H&V	(Peak)	✓		5040
Building H&V	(Operating-Day)	✓		3930
	(Operating-Night)			3656
Humidification	AHU	✓		750
	Local			95
DHW		✓		1579
Misc LPS		✓		69
HPS			✓	441

Fig 3.3 Calculated building loads-2001 Feasibility Study

From these individual heating loads the typical operating loads for the facility and energy requirements were then calculated using a modified degree-day method. For DHW production the energy consumption was calculated based on the predicted demand. Misc LPS and HPS energy was based on estimated service factors of 50% resulting in summarized loads as follows:

Heating Loads	
Peak Load (LPS)	7533kW
Peak Load (HPS)	441kW
Operating load (Day)	5285 kW
Operating load (Night)	4320 kW
DHW Energy	2100 kWh/day
Annual Energy	
Fuel fired system efficiency	0.7
Historic degree days	6910.7
Annual total energy	11 840 MWh
Annual LPS energy	10 870 MWh
Annual FO	1 559 000 L
Annual FO cost ($0.45/L)	$701 500

Fig 3.4 Calculated WGH building mechanical loads and annual energy-2001 Feasibility Study

While relatively accurate these values did not include for the Thompson Building. To allow an accurate comparison between the current DOE2.1e energy analysis and the 2001 Feasibility Study the values for the 2001 Feasibility Study were updated to reflect the Thompson Building. To accomplish this building ventilation loads were estimated using information from the construction contract TAB report. Building heat loss values were calculated on a m2 basis using the m2 heat loss values for the WGH.

Using this method a calculated peak load of 467kW with a corrected operating load of 430kW was obtained for the Thompson Center. Updating the summarized values from the 2001 Feasibility Study resulted in the following values.

Heating Loads	
Peak Load (LPS)	8000kW
Peak Load (HPS)	441kW
Operating load (Day)	5715 kW
Operating load (Night)	4750 kW
DHW Misc LPS Energy	948 MWh/year
Annual Energy	
Fuel fired system efficiency (estimated)	0.7
Historic degree days	6910.7
Annual total energy	12 800 MWh
Annual LPS energy	11 830 MWh
Annual FO	1 685 000 L
Annual FO cost ($0.45/L)	$758 300

Fig 3.5 Calculated WGH and Thompson Center mechanical loads and annual energy-2001 Feasibility Study Base

As a result of adding the Thompson Building load the updated values from the 2001 Feasibility study results in an increase of only about 10% in the calculated energy and design values. In comparison the active building footprint of the Thompson Building adds a service area increase of 33% to the WGH. The hospital, however, has significantly higher building energy demands on a unit basis due to the very high ventilation rates and service heating requirements while the Thompson Building outdoor air ventilation rates are very low resulting in a low building unit basis energy demand.

Comparing the updated 2001 Feasibility Study values to the DOE2.1e values shows a trend to slightly lower fuel oil consumption and peak loads for the DOE2.1e model. As noted previously peak coincidental operating load by the DOE2.1e model is 4920kW. The calculated load from the Feasibility Study is 5715kW for a difference of 16%. Fuel consumption shows a similar difference of about 14% between the DOE2.1e correlated annual value of 1 475 900L and the 2001 Feasibility Study value of 1 685 000L. These variations are most likely due to the excellent compensation for internal heat gains that the DOE2.1e model includes in calculating the coincidental heating loads and are typical when comparing degree-day models to 8760hr models.

In summary the DOE2.1e model shows very good correlation to the 2001 Feasibility Study values when the Feasibility Study values are updated to include the Thompson Center load. Peak coincidental heating load calculated using historic fuel oil consumption and a degree-day model is within 10% of the DOE2.1e model. Similarly calculated operating loads and annual energy consumption using the calculated operating load and a modified degree-day model are within 15% of the DOE2.1e model. In both cases the DOE2.1e model results in lower values, which is typical for this type of comparison showing very good correlation between the results for the two estimating methods.

Boiler Capacity Optimization

Also generated as a component of the DOE2.1 model were boiler load duration curves. These curves show the boiler load vs percentage of all hours and percentage of load hours. These curves, see Figures 3.1 and 3.2, are the most important aspect of the DOE2.1e model as they allow accurate selection of the optimum secondary sales boiler capacity.

As noted in the previous section the variation between the 2001 Feasibility Study and the DOE2.1e model values was relatively small. The ability of the degree day model, however, to optimize the boiler selection and to accurately calculate the annual energy offset from fuel oil to electrical energy is limited. Conversely, the DOE model allows very accurate hourly comparison of the required building load vs. potential electric boiler utilization. By using this comparison very accurate optimization of the boiler selection can be accomplished.

The load duration curves for the correlated model are shown in Figures 3.1 and 3.2. Both curves show a relatively flat duration curve until approximately 10% of total hours. At this time the load curves exhibit a rapid change in slope to meet the peak demands. This is relatively typical for heating plant applications with large weather dependent loads such as building heating. Selecting the start of this change in slope as the preliminary selection point results in a total electric boiler capacity of 2500kW. This boiler capacity would then be capable of meeting 94.7% of the total building heating demands, an excellent energy offset.

To optimize the selection from a load perspective a brief iterative method was used. This is reflected in Figure 3.6, which plots secondary sales boiler capacity vs annual electrical energy. This plot exhibits a similar change in slope occurs at about 2.5MWh boiler capacity as the load duration curves indicating an optimum boiler selection at this value.

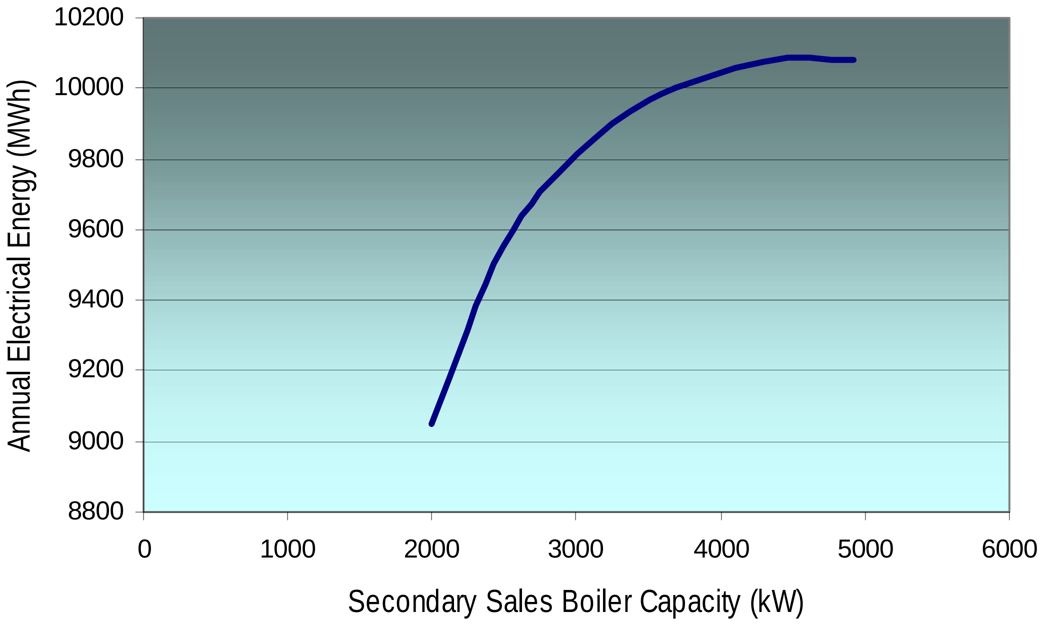


Fig 3.6 Secondary Sales Boiler Capacity vs. Annual Energy Offset

Using the 2.5MW boiler capacity results in a total annual energy offset to electrical energy of 9554MWh or 94.7% of the total annual heating requirement. This assumes 100% electrical energy availability from the utility. This 100% availability is, however, in reality too high. For calculation purposes the 2001 Feasibility Study applied an availability factor of approximately 92% by assuming 0% secondary sales electrical energy during January. To allow a relatively accurate comparison this 92% availably factor when applied to the DOE2.1e model annually results in a correct annual energy offset of 8790MWh or 87% of the total annual heating requirement.

These values are based, however, on assuming 100% system efficiency for the electric boiler. This will not, however, be the case. Standby losses and distribution in-efficiencies will result in a lower system operating efficiency. To account for this loss boiler capacity should be increased by the reduction in efficiency to deliver the desired annual offset electrical energy value. From the 2001 Feasibility Study the electric boiler system efficiency was placed at 90%. Applying this factor results in a final selection of 2.7MW for the boiler capacity to offset 8790MWh annually. Using this final capacity would result in a secondary sales capacity factor of 37% for appliance capacity with an offset capacity factor of 37%.

In comparison the 2001 Feasibility Study when updated to reflect the current values shows an annual electrical energy offset of 5050MWh a value approximately 36% less than the DOE2.1 value with capacity factors of only 23%. These large differences are due primarily to the very poor ability of the DD model used in the 2001 Feasibility Study to account for the fixed non-weather dependent loads.

4.0 Capital Costs and Financial Analysis

Capital investment costs were estimated during the 2001 Feasibility Study as Option 3 for providing new electric boilers in various capacities. These costs have been reviewed and updated to reflect providing for a revised total boiler capacity of 2.7MW.

Detailed discussions of the various recommended retrofit methods were also discussed in the 2001 Feasibility Study and will be outlined in greater detail during the design development stage of this project. In general, however, a single boiler of 2.7MW or two smaller boilers of 1.35MW output capacity each are proposed. These boilers will be installed within the existing Energy Center in the Generator Room in the space programmed for the future cogeneration generators. To install the boilers in this space it will be necessary to remove a portion of the roof and insert the boiler(s) through the opening using a crane. The boilers could then be moved into place within the generator room, a relatively simple operation. During the Feasibility study various boiler manufacturers products were reviewed, however, the Lattner Model #2000LS tended to the best spatial fit and the cost estimates have been updated based on this equipment.

The new updated capital costs for the new boilers are approximately equal to those of in the 2001 Feasibility Study. Two options have been considered for comparison. The first option is to provide two boilers at approximately 1.35MW per unit. Mechanical costs for this option are estimated at $452 400. The second option is to provide a single 2.7MW boiler at a slightly lower cost of $432 400. Electrical costs for either option are essentially equal at $163 500 for a total capital cost of between $615 900 and $595 900. These costs include all capital and construction costs plus a 20% construction contingency. The costs do not include design costs, taxes or administration costs. With the addition of engineering costs the total project value is estimated at between $698 800 to $676 600.

To allow for an accurate and flexible cost analysis the NRCan RETScreen analysis tool was used as a financial estimating tool. To accomplish the finanical analysis the Waste Heat Recovery model was used with the annual energy and recovered energy values forced to match the annual heating demand and annual electrical energy offset calculated by the DOE2.1e program. This allowed the use of the financial summary and green house gas tools included in the RETScreen spreadsheets. For both options of boilers similar energy cost escalation rates, inflation and discount rates were used. The discount rate was based on a base ASHRAE Handbook rate of 4.5%, which reflects the USDOE recommended rate. Inflation was set to 3% and fuel escalation to 5%. In addition project life was set to 25 years that reflects a typical life cycle for an electric boiler. Secondary sales electric energy was set at $0.033/kWh and fuel at $0.45/L.

Based on these financial parameters payback on either option is excellent. For the two 1.35MW boilers a positive cash flow occurs in 2.6 years with simple payback occurring in 2.9 years. The slightly lower capital cost of the single boiler option results in a positive cash flow of 2.5 years and a marginally accelerated simple payback of about 2.8 years.

These very rapid positive cash flow and paybacks occur as a result of the difference between energy costs. As noted the annual energy offset to electrical energy is valued as a direct credit and 100% appliance efficiency at an equivalent energy unit value of $0.033/ekWh. In comparison the equivalent energy cost (when adjusted for appliance efficiency at 80%) for fuel oil at $0.45/L is $0.052/ekWh or approximately 60% higher than the electrical energy cost. Thus for every kWh of energy provided by secondary sales a savings of 60% in operating costs vs fuel oil is realized resulting in excellent savings.

In comparison the 2001 Feasibility Study adjusted to reflect the fuel cost of $0.45/L results in a payback of about 5.5 years, or close to 90% longer than the current calculated value. This variation is again to the very poor ability of the DD model used in the 2001 Feasibility Study to account for the fixed non-weather dependent loads resulting in a lower annual electrical energy offset.

5.0 Green House Gas Reduction

The RETScreen analysis tool was also utilized as a simple means to estimate the reduction in green house gas emissions by using secondary sales to offset the fuel fired energy. From the analysis tool an annual GHG emission reduction of 3776 tco2/year is estimated based on an annual energy offset of 8790MWh.

6.0 Conclusions

In general excellent correlation between the 8760hr DOE2.1e model and updated values from the 2001 Feasibility Study using a degree-day estimating method when corrected for the addition of the Thompson Center have been achieved. Peak coincidental load is within 10% using the different models along with a variation of about 14% in annual fuel consumption. In both cases the DOE2.1e models are lower due to the more accurate estimating methods of the DOE2.1e tool.

A more significant variation is noted in estimating the annual energy offset from fuel oil to electrical energy. To estimate the total energy offset and to optimize the boiler selection load duration profiles were developed from the DOE2.1e model. Using this method an optimized boiler selection of 2.7MW (corrected for system efficiency) was selected with an annual energy offset of 8790MWh for a secondary sales availability factor of 92%. This results in a total offset of 87% of the annual heating requirement with a resulting reduction in green house gases of 3460 tco2/year. For the same boiler size if the secondary sales availability factor is improved to 100% the total offset will optimize at 9554MWh or 94.7% of the total annual heating and a greenhouse gas reduction of 3776tco2/year. In comparison to the 2001 Feasibility Study these values are approximately 36% higher resulting in improved financial feasibility and secondary sales boiler capacity factors reaching 40%.

As a result of the higher annual offset energy and resulting savings financial feasibility was considerably improved. For the two possible boiler options of either two 1.35MW boilers or a single 2.7MW boiler, positive cash flow is realized in slightly over three years with payback occurring in about 3 years. This is a reduction of over 2 years in comparison to the 2001 Feasibility Study values.

In conclusion excellent correlation between the current models and the 2001 Feasibility Study has been proven. In addition annual energy offset from fuel oil to secondary sales electrical energy is higher than originally calculated in the Feasibility study resulting in excellent payback and project viability.