Review of the Proposed Highwood Generating Station

City of Great Falls, Montana

February 2007

R·W·BECK

February 28, 2007

Ms. Coleen Balzarini
City Controller/Director
City of Great Falls
2 Park Drive South
Great Falls, Montana 59403

Subject: **Independent Review of the City of Great Falls Proposed Investment in the Highwood Generating Station**

Dear Ms. Balzarini:

Enclosed is our independent review of the proposed Highwood Generating Station (the "Project") and its anticipated relative competitive position in the regional electric wholesale market. This review has been produced for the City as a part of its decision making process regarding the proposed financing of a 25 percent share of the Project. With respect to the opinions and observations provided in this review, we emphasize that this review should be read in its entirety.

We would like to acknowledge the cooperation of Southern Montana Electric Generation and Transmission Cooperative, its project engineering firm, Stanley Consultants and its environmental engineering firm, Bison Engineering. In addition we would like acknowledge the cooperation of the City of Great Falls staff on this assignment. The assistance of all parties has been important to the production of a timely and well described review.

We appreciate the opportunity to be of service to the City of Great Falls.

Sincerely,

R. W. BECK, INC.

Angelo Muzzin
Principal and Senior Director

Ronald J. Moe
Principal and National Director

1001 Fourth Avenue, Suite 2500 Seattle, WA 98154-1004 Phone (206) 695-4700 Fax (206) 695-4701

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Table of Contents

List of Tables

REVIEW OF THE PROPOSED HIGHWOOD GENERATING STATION

Introduction

R. W. Beck, Inc., has been retained by the City of Great Falls, Montana (the "City") to undertake a limited independent review of the proposed Highwood Generating Station ("HGS" or the "Project") and its anticipated relative competitive position in the regional electric wholesale market. The Project will be a 250-MW coal-fired generating station and is planned to be in operation in 2011. The Project is being developed by the Southern Montana Electric Generation and Transmission Cooperative, Inc. ("SME"). SME's members include five Montana distribution cooperatives and the City of Great Falls. SME anticipates it will begin construction of the Project in June of this year.

This review is being undertaken as a part of Electric City Power, Inc.'s ("ECPI") decision making process to proceed with the financing of its 25 percent interest in the Project. ECPI is a corporate entity that is owned by the City and is engaged in the sale of power, at retail, to certain large key accounts in the Great Falls area. ECPI operates as a licensed competitive electricity supplier under Montana's "electric industry restructuring and customer choice law." ECPI's entitlement in the Project will provide power, post 2011, for sale to its key accounts, as further described below.

SME anticipates it will soon receive final loan guarantee approval from Rural Utility Service ("RUS") to fund the construction of the Project. RUS' loan guarantee will fund that portion of the Project that will provide power to the distribution cooperatives. Likewise, ECPI anticipates it will begin its financing program for its 25 percent interest in the Project in parallel with SME.

Our analysis is a limited review of a number of issues surrounding the Project including:

- Anticipated construction cost and schedule
- Environmental and permitting issues
- Anticipated operating costs
- Fuel and fuel transportation plans
- Electric transmission issues including interconnection and deliverability
- Forecast of cost of power from the Project
- City's power sales plan

In undertaking our review, we examined a number of documents prepared by SME, Stanley Consultants ("Stanley") (Project Engineer), Bison Engineering (Project Environmental Engineer) and ECPI. In addition, the review included meetings and conference calls with all of the parties. In the area of fuel issues, R. W. Beck retained J. T. Boyd Company ("Boyd"), an internationally recognized authority on coal related issues, to augment our review team.

The following is a discussion of our review and findings.

Project Overview – Design and Project Plan

The Project will be developed on an approximately 740-acre parcel of land located approximately nine miles east of Great Falls, Montana at an elevation of approximately 3,300 feet above sea level. Access to the site is via US Highway 87, State Highway S-228, and Salem Road. The source of makeup water for the Project is the Missouri River approximately 3 miles away from the Project site. An intake structure at the river and associated pipeline and pumping facility are to be constructed for this purpose. Wastewater from Project operations is to be sent to Great Falls for processing via a buried pipeline. A 6.3-mile-long rail spur is to be built for the purpose of delivering coal to the Project site. Power generated by the Project will be delivered to the existing 230-kV Great Falls Substation via a new 9.2-mile-long transmission line. Ash is to be disposed of on site in a monofill that is to have a clay liner and groundwater monitoring wells.

The Project as planned will consist of a circulating fluidized bed ("CFB") boiler technology designed to combust Powder River Basin ("PRB") coal. Fluid bed technology has been successfully applied to numerous processes in many different industries since 1926 and applied to the combustion of coal since the late 1950s. In the 1970s the technology gained interest in the U.S. as a result of its ability to control sulfur dioxide emissions without the need for a separate flue gas desulphurization system. Since then the technology has continued to evolve as more units were built and a wide range of fuels were used. Alstom Power ("AP") is an internationally known CFB equipment manufacturer with many CFB facilities installed worldwide. The Project's CFB is to be a top supported, natural circulation, single drum, reheat unit designed to produce 1,785,100 pounds of steam at 1,005°F and 2,487 psig per hour. AP's design reflects the industry's current state of technology in CFB plants.

In addition it has been confirmed that, based on information contained in AP's "Evaluation of Southern Montana Electric's Spring Creek Coal in AP's Multi-use Test Facility for CFB Use," dated May 9, 2005 (the "AP Report"), no fuel related issues were identified during the AP test that would limit the use of Spring Creek coal (the proposed fuel source for the Project) for commercial CFB applications. There was no evidence of bed agglomeration and convection tube fouling was low over the entire range of conditions evaluated. The AP Report also states that: "the combustion performance of this fuel was very good, and emission during the testing generally fell within expected ranges."

There are over 400 CFB steam generators in operation in the world today. CFB technology has been demonstrated in sizes over 300 MW, covering an extremely wide range of fuels. The CFB technology proposed is a sound, proven method of energy recovery. We expect the Project to be technically sound if constructed, operated, and maintained as presently proposed by SME and the design proposed by AP has taken into consideration the current environmental, license, and proposed permit requirements that the Project must meet.

Steam generated in the CFB will be converted into electrical energy in a Toshiba reheat condensing steam turbine generator (“STG”). The STG configuration will include seven extraction points for feedwater heating to improve cycle efficiency. The STG is to be a 60 hertz hydrogen cooled unit rated at 370 MVA with a lagging power factor of 85 percent at 21 kV. An STG step-up transformer increases the voltage from 21 kV to 230 kV for interconnection with Northwestern Energy’s (“NWE”) transmission system. The STG proposed is similar to what is installed on other power generation facilities.

Auxiliary systems necessary to support operation at base load on a continuous basis will need to be included. The Project is to be operated by SME with a staff of 62 personnel, which is within the range we would expect for a plant of this size and technology. SME personnel are to be trained by East Kentucky Power Cooperative staff that currently maintain and operate its E. A. Gilbert Unit 3 power generation facility, which is similar in size and technology to the Project. We have not reviewed any of the contractual agreements between SME and East Kentucky Power Cooperative in this regard nor have we visited the E. A. Gilbert Unit 3 facility or reviewed the facility’s operating history to assess East Kentucky Power Cooperative’s capabilities with regard to providing operating and maintenance training. We do note that this will be the first coal-fired generating plant that SME will be responsible for operating and maintaining.

Environmental and Permitting Issues

Status of Permits and Approvals

The Project must be operated in accordance with applicable environmental laws, regulations, policies, guidelines, codes and standards. Table 1 identifies the key permits and approvals required for the construction and operation of the Project. Our review was based on information received at meetings with SME and its consultants. The opinions presented herein are based on such information received and representations made during the meetings. While we have independently verified certain of the information received, we did not conduct independent assessments in every case due to the schedule and scope limitations of our study.

Table 1
Key Permits and Approvals Required for
Construction and Operation of the Project

Permit or Approval	Responsible Agency	Status	Comments
Federal			
Environmental Impact Statement (“EIS”)	Rural Utility Service (“RUS”) and Montana Department of Environmental Quality (“MDEQ”)	Final EIS issued January 2007 with Record of Decision (“ROD”) expected March 2007	Required for compliance with the National Environmental Policy Act (“NEPA”) in association with RUS financing and by the Montana Environmental Policy Act for issuance of an air quality and other permits
Notice of Construction and Alteration	Federal Aviation Administration	To be obtained prior to initiation of construction of the stack	Required for construction of stack to indicate no impact to air navigation
Joint Permit Application, Clean Water Act Section 404 and Safe Harbors Act Section 10	US Corps of Engineers/MDEQ	Nationwide Permit No. 12 issued November 20, 2006	Required for construction activities on the banks and in the bed of the river involving water intake structure and transmission line encroachment onto river; water quality Section 401 certification issued by MDEQ
Spill Prevention Control and Countermeasure (“SPCC”) Plan	United States Environmental Agency (“USEPA”)	To be prepared prior to start of operation	Required as per 40 CFR 112, Oil Pollution Prevention regulations, if the Facility stores more than 1320 gallons of oil at the site (including electrical transformer oil)
Hazardous Waste Identification Number	USEPA/MDEQ	USEPA Identification to be obtained prior to start of operation	Required for the management/disposal of hazardous waste
Risk Management Plan	USEPA	To be prepared prior to start of operation	Required due to the use of ammonia on site for nitrogen oxides control
State			
Air Quality Permit/Prevention of Significant Deterioration (“PSD”) Permit	MDEQ	Application submitted; draft permit issued; final permit issuance expected within 30 days after issuance of Final EIS by the RUS	Required for an air emission source. Sets forth air emission limits, testing, monitoring, record-keeping and reporting requirements
Title V Permit to Operate	MDEQ	Application filed	Incorporates all air quality requirements into one permit
Title IV Acid Rain permit	MDEQ	Application must be submitted 24 months prior to the start of operation	Required for compliance with Acid Rain Provisions of the Clean Air Act Amendments of 1990. Requires the Facility to hold SO_2 allowances to cover its annual SO_2 emissions.
General National Pollutant Discharge Elimination System (“NPDES”) Permit Associated with Construction Activity	MDEQ	To be obtained prior to the start of construction	Required for stormwater management on-site during construction. A Stormwater Pollution Prevention Plan must be prepared
General NPDES Permit Associated with Industrial Activity	MDEQ	To be obtained prior to the start of operation	Required for stormwater management on-site during operation. A Stormwater Pollution Prevention Plan must be prepared
Industrial User Permit	City of Great Falls	To be obtained prior to the start of operation	Required for the disposal of wastewater to City’s municipal wastewater treatment plant

Table 1 (continued)
Key Permits and Approvals Required for
Construction and Operation of the Project

State, continued			
Solid Waste Disposal Approval/License	MDEQ	To be obtained after issuance of the ROD	Utilities are exempt from this requirement but SME is voluntarily submitting an application to demonstrate "no-migration potential"
State Lands Use Approval	Montana Department of Natural Resources and Conservation	Application submitted November 11, 2006; approval pending	State Land Board meeting is scheduled for the month following the issuance of the ROD. Required for encroachment onto state lands due to construction of water intake from the Missouri river and transmission line crossing
Montana 310 and 318 Surface Water Permits	MDEQ	Issued June 15, 2006	Required for protection of water quality
Beneficial Water Use Permit	Montana Department of Natural Resources and Conservation	Approval to be issued; expected February 2007	Change in Point of Divergence
Local			
Zoning Change Approval	Cascade County Commissioners	Issued November 29, 2006; zoning change under legal challenge/appeal	Required to change the zoning of the site from agricultural to industrial
Construction Permit	Cascade County	To be obtained prior to start of construction	Required for compliance with building codes and standards

Based on our review, we offer the following observations relative to the status of permits and approvals and other regulatory requirements with which the Project must comply:

- SME has identified the key permits and approvals required for the construction and operation of the Project. While not all key permits and approvals have been obtained to date, SME is in the final stages of potentially acquiring such key permits and approvals including the NEPA approval from the RUS and the air quality permit from the MDEQ.
- The draft air quality permit sets forth air emission limits and other conditions with which the Project must comply. Such limits and conditions are considered by the MDEQ as representing Best Available Control Technology ("BACT"). Furthermore, these emission limits and other conditions are comparable to such limits and conditions imposed on air quality permits at other recently permitted coal-fired power plants with which we are familiar. Air emissions from the circulating fluidized bed boiler will be controlled by limestone injection into the boiler (sulfur dioxide control), a fabric filter baghouse (particulates control), a hydrated ash re-injection system (sulfur dioxide control), a selective non-catalytic reduction system (nitrogen oxides control), collectively referred to in the draft air quality permit as an integrated emission control system, and potentially a sorbent injection system for the control of mercury should the integrated emission control system not prove capable of meeting the mercury emission limits set forth in the draft air quality permit. With respect to the potential use of the Integrated Gasification Combined Cycle technology, the RUS consistent with the findings of

the MDEQ, states in the Final EIS that the technology is "not currently cost-effective and requires further research to achieve an acceptable level of reliability; except for still undemonstrated potential to sequester carbon dioxide, does not enjoy significant emissions advantages over the CFB."

- The draft air quality permit has set forth emission limits for mercury emissions from the Project that allows it to comply with the Clean Air Mercury Rule ("CAMR") and the state regulations implementing the CAMR. According to SME, the costs for potentially purchasing mercury allowances and/or reducing mercury emissions have been incorporated into the Project's capital and operation and maintenance costs.
- Test burns conducted by AP, the boiler manufacturer, using coal from the likely fuel sources for the Project indicate that the Project should be capable of meeting the air emission limits set forth in the draft air permit.
- The zoning approval for changing the zoning of the proposed site from agricultural to industrial has been legally challenged. We cannot offer any opinion as to the outcome of such legal challenge or any other legal challenges or permit appeal requests that might be initiated in the future associated with any permit issuance. Such legal challenges or appeals, if any, have the potential to influence project schedule and costs.
- There are a number of issues commented on by the public during the NEPA process and the air quality public review process. For example, these issues include evaluation of alternatives, emission of mercury, and emission of carbon dioxide. Such issues are typical of issues raised at other recently proposed coal-fired power plants with which we are familiar. Each respective agency (particularly RUS and the MDEQ) will evaluate public comments prior to issuing a final decision on permits and approvals for the Project.
- The impact of the Project on the historic Lewis and Clark Trail has been identified as a key issue during the NEPA process. As a result of the issue being raised, the site for the Project has been moved so as to be outside the Trail area. According to SME, SME is undergoing discussions with the appropriate agencies to define mitigation measures to minimize the impacts as much as practicable and allow the Project to proceed.
- The Project will be subject to Title IV of the Clean Air Act Amendments of 1990 (Acid Rain Provisions) whereby each unit within a facility must possess sulfur dioxide allowances to cover its emissions. The state of Montana is not subject to the newly adopted Clean Air Interstate Rule ("CAIR") by the USEPA and as such will not be subject to the additional requirements of CAIR. The future cost of sulfur dioxide allowances will be market dependent and could be lower or higher than the current values for such allowances. The exact number of allowances to be required will depend on the utilization of the units. According to SME, the cost for purchasing allowances to comply with the acid rain provisions have been incorporated into the Project operation and maintenance costs.

- There are a number of potential future regulations and potential future legislation that, if promulgated, could increase capital expenditures and operations and maintenance costs at existing and new generating facilities. Such potential regulations and legislation include particulate matter of 2.5 microns or less, regional haze, regional visibility, potential reductions of sulfur dioxide and nitrogen oxides allowances beyond 2010, toxic emissions control and carbon dioxide control. The schedule and specific regulations to be promulgated are not presently known and as such have not been evaluated herein. It should be noted that Bison Engineering, as a part of the air permit modeling has determined that a particulate matter requirement of 2.5 microns can be met by the Project.
- With respect to potential future carbon dioxide regulations, the specific impacts to the project cannot be determined at this time due to the lack of specificity on the future regulations and evolving policy debate. However, future carbon dioxide regulations will likely occur and will increase the cost from the Project. In addition, the wholesale market prices for energy in the Pacific Northwest will also increase due to the future regulations. While carbon dioxide emissions from gas-fired facilities are less than carbon dioxide emissions from coal-fired facilities, both types of plants will be impacted by the future regulations. Since gas fired generation is often the generation type that sets wholesale market prices (now and in the foreseeable future), such future regulation impact on natural gas fired generation is expected to cause market prices to rise.

Anticipated Cost and Schedule

Capital Cost Estimate

We were provided with the Project budget by Stanley with a Project capital cost estimate, which includes the estimated direct costs for facilities, indirect costs, owner's costs and interest during construction. Contract negotiations that provide firm or near firm pricing and that are currently concluding, cover approximately 50 percent of the capital cost estimate for the Project. Our review of this estimate was, with some exceptions, based on benchmarking it to the cost-per-kilowatt of other coal-fired project costs. Using the net output of 250 MW discussed above, Stanley's expected cost of $2,712 per kW is below the range of costs for other coal-fired projects of this size with which we are familiar.

The exceptions noted above concern engineering, construction management, start-up, contingency and owner's cost budgets. We were informed by Stanley there are 175,000 hours for engineering and 100,000 hours in the budget for construction management and start-up. In our opinion this is low for a project of this size. Stanley stated it is using engineering from other similar projects and can design the Project with less hours and there are hours in SME's and AP's budget for construction management and start-up. The contingency budget is $33,974,000. We believe this contingency value is lower than what would be anticipated for a project of this type and size. We were advised by Stanley that the contingency budget was based upon their experience at the Eastern Kentucky Site. We concur that certain aspects between the projects may warrant some comparison; however, a project specific contingency analysis is recommended due to the various differences between the two projects. Some aspects that may alter the contingency estimate would include labor production cost, material pricing, location, and other cost related items. This analysis is also viable since engineering has just started and the Project has not received its permits.

The budgeted interest during construction amounts to $68,269,000. We did not review the basis of this budget line item.

We believe SME's budget of $14,115,000 for owner's costs appears lower than we would expect for a project of this size. SME's budget includes items such as start-up personnel, start-up spares, fuel, power, consultants, site management, home office support and other miscellaneous costs. Owner's costs, exclusive of interest during construction, can often vary anywhere between 10 and 20 percent of the capital cost budget. It may be appropriate for Stanley and/or SME to reevaluate the owner's scope of work for the Project.

We conclude that the total Project budget may be lower than what will be required due to potentially higher costs for engineering, construction management, start-up, owner's cost and contingency budgets.

The capital costs for the Project, based on the information provided to us, appears to be on the low side of the expected range of costs we would expect. It should also be noted that a significant portion of the Project's costs are not fixed at this point and could be subject to labor and material shortages or price increases as we have seen in other coal plant developments throughout the United States. As such, a total capital cost of $2,880 per kW is used in the R. W. Beck Sensitivity Case, described below, to see how a higher capital cost affects Project competitiveness.

Project Schedule

We were provided a project schedule by Stanley containing approximately 150 activities and indicating the following key dates: award turbine generator contract December 29, 2006; award boiler contract April 3, 2007; DOE Record of Decision on Environmental Impact Statement on March 20, 2007; contractor limited notice to proceed on January 2, 2007; start of construction June 11, 2007; substantial completion April 1, 2011; and commercial operation on June 1, 2011. This comprises a 48-month construction schedule which includes full commissioning of the Project.

Currently "Limited Notice to Proceed" authorizations have only been given to the STG contractor. The LNTP to the boiler contractor is expected to be given on April 1, 2007. Final deliveries of the CFB and STG are scheduled for December 2008 or month 20, which leaves adequate time to install and erect these units. Overall engineering, procurement, construction, and commissioning efforts and scheduled durations and sequencing of these tasks appear adequate to support the completion of the Project within 48 months after the start of construction.

Anticipated Operating Costs

We reviewed the projected operating and maintenance ("O&M") costs provided by Stanley. This included an assessment of non-fuel operation and maintenance costs, owner expenses, and fuel related expenses. To evaluate the adequacy of annual O&M expenses, we focused on non-fuel operation and maintenance costs associated with the direct operation of the plant, referred to here as the "Production Related Non-Fuel O&M Expenses" to allow for comparison of O&M costs on the same basis.

In doing our assessment, Production Related Non-Fuel O&M Expenses are adjusted to a common basis before comparison. These costs do not include limestone or ash disposal cost. Expenses are adjusted for regional cost differences, capacity factor, fuel quality, plant technology, and escalated to a common year.

Based on comparing the Stanley Production Related Non-Fuel O&M Expenses with other similar projects in our database it appears that the Stanley O&M cost assumption of $5.23/MWh (2011 dollars) may be in the lower range. The $5.23/MWh is based on Stanley's assumed 1 percent per year inflation rate and other cost assumptions. We assume inflation to be 2.4 percent a year and the Production Related Non-Fuel O&M Expenses to be approximately $9.86/MWh (2011 dollars). In addition to assuming a different inflation rate, the major cost differences between what we assume and what Stanley has assumed are associated with the fixed plant O&M cost and total variable O&M cost. As a result of these different assumptions, we have requested Stanley to run a sensitivity analysis (R. W. Beck Sensitivity Case described below) in their forecast model based on our alternative assumptions for projected O&M costs.

Anticipated Fuel and Transportation Costs

Overview

We reviewed the assumptions and supporting documents related to fuel and fuel transportation issues for the Project.

The Project is planned to use CFB technology and consume 22 trillion Btu's annually. This is equivalent to approximately 1.2 million tons of coal per year (at 9,350 Btu/lb). If the Project operates for 50 years, total coal requirements over the Project life could exceed 60 million tons.

Review of Fuel and Transportation Assumptions

Information regarding the fuel and transportation assumptions used in forecasting the cost of operations of the Project was provided to us by SME. In addition discussions regarding fuel and transportation assumptions were held with representatives of SME and Stanley. It is our understanding that for the proposed fuel supply plan, Stanley primarily relied on an initial report prepared by Norwest that broadly assessed the potential sources of coal for the Project and on two subsequent reports prepared by Boyd.

We are in possession of the two Boyd reports which addressed: 1) coal resources in the Great Falls, Montana area that would be suitable as a fuel source for the Project and 2) a draft of a conceptual evaluation of coal quality, quantity and mining cost of an underground coal mine delivering fuel to the Project.

Additionally, we received limited documentation regarding fuel and transportation assumptions. Generally, this information provides overview data regarding potential coal mine sources obtained from producer sales representatives or producer websites. We also received a copy of the assumptions used to develop the cost projections for the Project, which included assumptions regarding the cost of fuel, transportation cost and heating value and the AP Report that evaluates the use of Spring Creek coal for the Project. Our review of the AP Report was limited to the conclusion that supports Spring Creek coal as a potential source of fuel for the Project.

Based on discussions with SME and Stanley, an important objective of the Project is to obtain coal from Montana coal mines. At this point, Rio Tinto’s Spring Creek Mine, Kiewit’s Decker Mine and Westmoreland’s Absaloka Mine are existing coal producing operations in Montana that have been identified as the most likely primary sources of coal for the Project.

Alternatively, building a new bituminous underground coal mine dedicated to supplying the Project has been considered. This potential source was the focus of two previous studies undertaken by Boyd for Stanley. Our understanding is that SME and Stanley have limited the use of the Boyd reports to conclude or assume that a dedicated mine in the Great Falls area is likely to be a more costly alternative to existing mines in both Montana and Wyoming. However, in the event of significant market price increases in other Montana and Wyoming based coal sources, the potential for developing such a mine could have value because it represents a potential alternative that could cap the total delivered cost of fuel to the Project.

Finally, sources of coal from outside of Montana (and in particular the PRB mines in Wyoming) are considered to be the ultimate “backup” source of coal if Montana coal is or becomes unavailable or uneconomic.

The pro forma fuel cost assumptions used by SME and Stanley are shown in Appendix A along with the alternative fuel cost assumptions used in the R. W. Beck Sensitivity Case, as discussed below.

Our understanding is that the assumption of a 2011 price of $8.50 per ton FOB mine cost for Spring Creek coal (or a mine of similar quality) is based upon published reports of the current prices for coal in the PRB of Wyoming. In our opinion, these prices represent the short-term “spot” market prices and are therefore unlikely to be representative of the price that the Project would likely receive under longer term purchase agreements. An alternative assumption used in the R. W. Beck Sensitivity Case is a 2011 price of $12.00 per ton FOB mine.

We also understand that the $9.00 per ton transportation rate is based upon recent and ongoing discussions with the BNSF Railroad. The $9.00 per ton rail rate appears reasonable at this stage of investigation.

The strategy of relying on existing Montana coal sources in competition with potential alternative sources of coal from a new Montana coal mine or mines in Wyoming is fundamentally sound and should result in SME obtaining the lowest cost sources of coal for the Project.

Given the vast amount of coal reserves in and surrounding Montana, the availability of coal to the Project is not a critical concern. However, there is greater uncertainty about whether the coal can be economically provided from existing or new mines developed in Montana simply because prices and availability from existing sources such as Spring Creek have not been fully explored and the prospects for developing a new mine in Montana have only been investigated at a cursory level. Additionally, the potential costs and implications of relying on coal sourced from Wyoming should be more fully assessed if this potential is to be considered in a financial analysis.

Generally, there is still a broad range of uncertainty surrounding the potential delivered cost of coal. This uncertainty should be evaluated – at a minimum – using high, low and base case scenarios for both the FOB mine cost of coal and the transportation cost. As part of this effort, SME should obtain a long-term price forecast for potential coal sources into the Project. This will aid in decisions regarding the proposed fuel strategy.

While the current assumption regarding rail rates used by Stanley appears reasonable, it should be recognized that BNSF railroad leverage will be increased as the Project proceeds closer to construction. Without a contract, there is no guarantee that the BNSF Railroad would not increase rates significantly.

The high sodium content of Spring Creek has been addressed by AP, but it remains an unusual coal constituent that bears close scrutiny if Spring Creek becomes a supplier of choice.

Going forward it is expected that SME will:

- Refine its fuel plan and forecasts to more definitively establish its fuel procurement strategy.
- Start to enter into contracts or letters of intent to begin firming up both commitments and pricing for coal and coal transportation.

Electric Transmission Issues, Interconnection and Deliverability

SME on behalf of the Project requested Network Resource Generator Interconnection to NWE's Great Falls 230-kV Substation from NWE on July 1, 2004. Revision 3 of the System Impact Study for that request was completed on October 10, 2006. The study identified an estimated $13,500,000 in Network System Mitigation Costs and $950,000 in Transmission Provider Interconnection Facility Costs.

Transmission Service

NWE is part of the Western Electricity Coordinating Council ("WECC") and the Northwest Power Pool. NWE does not participate within any currently operating Independent System Operator. Transactions within the market remain bilateral and there is no scheduled date for an energy imbalance or other real-time trading market. Within this market, the individual utilities have responsibility for providing transmission service on their system in line with the FERC Order 888 market, i.e., where each utility files an Open Access Transmission Tariff ("OATT") tariff rate and transmission wheeling costs are pancaked with neighboring utilities for transactions requiring multiple systems. Therefore, for deliveries from NWE to other utility systems, a transaction from the generator would pay the applicable NWE point-to-point transmission service rate and then the applicable utility (or utilities) rate(s) to the point of delivery to the buyer. Transmission losses apply to all transactions under the applicable OATT rate and are also pancaked.

We have been informed by SME that the Project will utilize existing network transmission rights to deliver power to its distribution cooperative members and ECPI.

Additionally, SME has requested point-to-point transmission service for 65 MW over NWE from the Great Falls Substation to the Burke substation in Idaho. This request was made to secure a transmission path, starting in 2011, that would facilitate the sale of excess power from the Project. The transmission service reservation has not yet been granted and a System Impact Study, if required, has not been undertaken as of this date. To reserve the transmission service, the applicable NWE OATT filed transmission service rate will apply, and SME will be required to pay the transmission service charge for the duration of the reservation.

Interconnection Agreement

Our review of the standard Large Generator Interconnection Agreement ("LGIA") and related studies in regard to the Project, did not raise specific transmission concerns relative to delivery of power from the Project.

Based on the Project's request for Network Resource Interconnection Service, the LGIA, when completed will identify the Project as a Network Resource. As such, in the event of transmission constraints on NWE's transmission system, the Project will be subject to the applicable congestion management procedures in NWE's transmission system in the same manner as all other network resources.

The standard LGIA includes Regional Council Requirements which are not limited to a Reliability Management System Agreement and the WECC Generation Interconnection Policy. The Project will be required to execute a Reliability Management System Agreement. Additionally, Exhibit A to Appendix C of the LGIA with Northwestern Energy requires the Project to maintain certain interconnection reliability standards as required by the WECC and NWE. The WECC Generation Interconnection policy provides information to generators regarding policies for connecting generation projects to the WECC transmission system. Based on our review, the standard agreements do not contain any unusual requirements or issues that may present additional transmission risk to the Project.

NWE will maintain the transmission system and transmission provider's interconnection facilities, while the Project will maintain the generating facility and the Project interconnection facilities. The Project will be responsible for all reasonable expenses including overheads associated with: (1) owning, operating, maintaining, repairing and replacing customer interconnection facilities and (2) operation, maintenance, repair and replacement of transmission provider's interconnection facilities.

The standard LGIA does not contain any unusual requirements or issues that may present risk to the Project's ability to interconnect to, and operate with the NWE Transmission Interconnection System.

Transmission Facilities Study

A facilities study has not yet been completed. The System Impact Study, which is the precursor to the facilities study, found that the Project can reliably be connected as a network resource to the NWE system at the point of interconnection, assuming the identified upgrades are constructed.

The review of transmission issues does not raise specific transmission concerns relative to delivery of power from the Project.

Forecast of Cost of Power from the Project

The City does not own or operate an electric distribution system; rather it operates as a licensed competitive electricity supplier under Montana's "electric industry restructuring and customer choice law." The City has aggregated, under a series of contracts, a 20-25 MW load from customers within the City, and is now seeking to increase its portfolio of long-term cost-based power sales contracts to utilize its 25 percent ownership share in the Project.

As a part of SME's information provided to RUS and as a part of its own internal planning, forecasts of the "busbar" cost of power for the Project are produced. A busbar cost of power forecast is a forecast, in $ per MWH, that includes all the costs to produce power, including capital costs, for the Project. Not included in a busbar cost of power are costs associated with transmission or other ancillary services. Given the low variable costs for the Project, the busbar estimate assumes the Project will produce power whenever it is available to do so.

The forecasts are undertaken by Stanley. This section reviews the projections of the busbar cost of power for the Project prepared by Stanley and the supporting assumptions as well as industry and market information and data in order to form independent conclusions covering the following aspects of the Project:

1. The likely conditions of the market for power in Montana and the Pacific Northwest at and beyond 2011.
2. The reasonableness of the forecast of busbar costs from the Project, including capital, operations, maintenance and fuel costs used by Stanley and SME in their cost projections.
3. The general cost competitiveness of the Project as a base load resource in the Pacific Northwest wholesale market.

Power Market in Montana and the Northwest

Montana is part of the WECC and the Northwest Power Pool. Transactions within the Montana market remain bilateral and there is no scheduled date for an energy imbalance or other real-time trading market. The closest trading hub to Montana and the Project is the Mid Columbia (Mid-C) hub. Market pricing at the Mid C hub, is the traditional proxy for benchmarking the expected revenues for market sales of generation from projects in the Northwest region. Market prices in the Northwest and the Mid C hub are predominantly driven by the price of natural gas and regional hydro conditions. The inherent volatility of both gas prices and hydro conditions drive the volatility in power market prices. The following tables depict the projected load and resource balance in the Northwest market as described in the WECC 2006 annual assessment. The tables present load requirements, available resources, and reserve margin over the 2007-2015 time period. Since the peak hour capacity assessment does not address the complicated energy limitations that apply to the Northwest hydro system, the tables also present the average megawatt (aMW) load/resource balance at three different hydro conditions scenarios. The tables below present the following observations:

- The capacity surplus that the Northwest market currently enjoys may not be sustainable over the long term or under a critical hydro condition scenario.
- The Northwest region is projected to add about 8,900 MW of new capacity between now and 2015, in which 42 percent of these additions is projected to be based on coal generation technology.

Table 2
Average Energy (aMW)
Load/Resource Balance – Northwest Region

	2007	2008	2009	2010	2011	2012	2013	2014	2015
Net Demand (aMW)	20,933	21,016	21,294	21,571	21,837	21,995	22,295	22,480	22,733
Net Resources (aMW)	23,033	23,339	23,396	23,458	23,523	23,588	23,681	23,687	23,687
Load/Resource Balance (aMW):									
Critica Hydro (1937)	2,100	2,323	2,102	1,887	1,685	1,593	1,366	1,206	954
Average Hydro - 50 yr	6,176	6,399	6,179	5,964	5,762	5,762	5,443	5,283	5,030

Table 3
Summer Peak (MW)
Load/Resource Balance – Northwest Region

	2007	2008	2009	2010	2011	2012	2013	2014	2015
Available Resources	49,736	47,552	45,747	45,185	45,023	45,249	45,369	45,359	45,362
Load Requirements	38,666	39,525	40,511	41,152	41,891	42,550	43,345	44,147	44,925
Power Supply Margin	11,070	8,027	5,236	4,033	3,132	2,699	2,024	1,212	437
Power Supply Margin (%)	28.6%	20.3%	12.9%	9.8%	7.5%	6.3%	4.7%	2.7%	1.0%

Table 4
Northwest Power Pool Area
Generation Additions and Changes
(MW)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total
Total	1,763	1,877	310	618	947	1,325	-	-	750	8,919
Coal	-	900	268	-	500	1,325	-	-	750	3,855

SME/Stanley's Busbar Cost of Power Forecast

The SME and Stanley busbar cost estimate, based on the assumptions outlined in Appendix A, is depicted in the following table:

Table 5
Busbar Cost for the Project

Year	$/MWhr
2011	43.40
2012	43.59
2013	43.79
2014	43.99
2015	44.18
2016	44.30
2017	44.50
2018	44.70
2019	44.91
2020	45.12

Based on our review of the assumptions associated with the Stanley forecast as discussed above and our review of the items described above, we requested an alternative set of assumptions be used for estimating the cost of power from the Project. This alternative set of assumptions and resulting forecast of busbar costs are described as the R. W. Beck Sensitivity Case. The alternative assumptions case primarily focuses on:

- Higher cost of fuel
- Higher cost of operating and maintenance costs
- Higher rate of future cost escalation
- Higher initial capital cost

The alternative assumptions are also shown in Appendix A.

Based on the alternative assumptions, Stanley provided an alternative busbar projection (the R. W. Beck Sensitivity Case). The following table depicts the Sensitivity Case busbar costs.

Table 6
R. W. Beck Sensitivity Case
Busbar Costs for the Project

Year	$/MWhr
2011	50.9
2012	51.9
2013	52.6
2014	53.3
2015	54.1
2016	54.7
2017	55.5
2018	56.3
2019	57.1
2020	57.9

Review of Market Prices as a Benchmark to Project Busbar Costs

In order to analyze the competitiveness of the Project in the Northwest regional market, we reviewed the estimated annual busbar costs and several other projections of Northwest annual market prices, including:

- Our own proprietary market price forecasts for the Northwest wholesale power market, including consideration of alternative forecasts of the price of natural gas and hydro conditions.
- Northwest Regional historical power prices trends.

- The most recent published forward prices for Mid-C and California-Oregon Border hubs.
- The most recent published EIA forecasts of natural gas and coal prices.

SME anticipated that the Project will go in service in 2011 and that the capacity of the Project will be greater than the needs of the SME members at that time. It is anticipated that this excess capacity will be sold into the wholesale market as long term firm contracts. These excess capacity sales would, over time, decrease in amount as the SME members' loads grow. SME's projections anticipate the excess capacity sales will end by 2020. In order to maximize the value of the excess power and make it readily available to the market west of Montana, SME has undertaken the steps necessary to reserve firm transmission service from the Great Falls substation to a substation in southern Idaho.

In addition, there will be times, during off peak periods, when SME will be able to sell short term energy, not otherwise needed to meet SME member requirements, into the hourly wholesale marketplace. It is anticipated that SME will generally be able to sell short term excess power from the Project into the wholesale market. However, pricing in the short term marketplace is volatile and during periods when the Pacific Northwest market is experiencing high river flows and related excess hydro production, the Project may be restricted in selling excess power in the hourly or short term marketplace.

Key Observations: Forecast of Cost of Power for the Project

We examined the busbar cost of power from Stanley's original forecast and are of the opinion that, under normal conditions and current expectations, the Project's busbar cost of power is expected to be competitive for a base load resource in the Pacific Northwest marketplace. In addition, the Project busbar cost of power under the R. W. Beck Sensitivity Case forecast is also expected to be competitive.

City's Power Sales Plan

ECPI is a corporate entity that is owned by the City and is engaged in the sale of power, at retail, to certain large key accounts in the Great Falls area. ECPI operates as a licensed competitive electricity supplier under Montana's "electric industry restructuring and customer choice law." Neither the City nor ECPI has a certified franchise area to provide retail electric service. The area in and around Great Falls is served by Northwestern Energy.

ECPI's ownership entitlement in the Project will provide power, post 2011, for sale to its key accounts, as further described below. ECPI currently purchases power at wholesale to sell to its key accounts. These purchases are made from PPL-Montana and others and it is anticipated that purchases from regional power marketers will continue until the Project is on-line. After 2011, a portion of ECPI's energy requirements, as well as ancillary services may be met from regional power marketers by way of SME. It is anticipated that SME will provide management of ECPI's power requirements program.

As mentioned above, ECPI has a number of key accounts under contract for sales of electric power. ECPI's current key accounts are listed below:

- The City of Great Falls (the municipal loads of the City)
- Great Falls Airport Authority
- Great Falls School District
- Great Falls Housing Authority
- Veolia
- Federal Express
- Montana Air National Guard
- Montana Refinery
- Benefis
- General Mills
- Meadowgold

The current contracts of ECPI represent approximately 20 to 25 MW of load. These contracts have termination dates ranging from 2008 thru 2011. ECPI is currently negotiating extensions of the shorter dated agreement to 2011.

The City's marketing plans include two main components:

- Subject to ECPI's decision making process regarding investment in the Project, ECPI will seek to have the term of the current sales agreements extended to match its financial commitment to the Project.
- ECPI is currently engaged in sales and marketing efforts to secure new customers for its power sales program. Current substantive discussions include other governmental entities in the state. ECPI is also engaged in discussions with various large businesses in Montana to serve their energy needs. These discussions and commitments are predicated on ECPI's decision making and financing of its portion of the Project.

Since no contracts for the new loads have been signed or committed at this point it is not possible to definitively discuss the amount of load ECPI will have in 2011. It is ECPI's plan to secure a number of new long-term commitments prior to committing to its long-term financing plan.

In preparation for financing of its ownership interest in the Project, ECPI will develop a financial plan that will include:

- A forecast of its revenues post 2011.
- A forecast of its expenses (including the cost of power and internal expenses) post 2011.
- A forecast of its debt service and debt service coverage ratios or other financial requirements.

Summary

This report has been produced for the City as a part of its decision making process regarding the proposed financing of a 25 percent share of the Project. This report is not sufficient in scope or disclosure to be used in the financing of ECPI's interest in the Project.

This report has been prepared on the assumption that all contracts, agreements, permits, statutes, rules and regulations which have been relied upon by us in preparing this report will be fully enforced and enforceable in accordance with their terms and conditions and will not be changed in any material way. We make no representations or warranties, and provide no opinion concerning the enforceability or legal interpretation of contracts, statutes, rules and regulations. In the preparation of this report and the observations that follow, we have made certain assumptions with respect to conditions that may exist or events which may occur in the future. While we believe these assumptions to be reasonable for the purposes of this report, they are dependant on future events, and actual conditions may differ from those assumed. In addition, we have used and relied upon information provided to us by others, including SME, Stanley, Bison Engineering, ECPI and the City. While we believe the use of such information and assumptions to be reasonable for the purposes of this report, we offer no other assurances with respect thereto, and some assumptions may vary significantly due to unanticipated events and circumstances.

Based on the information discussed above, our key observations are:

- The Project will be technically sound if constructed, operated, and maintained as presently proposed by SME and the design proposed by AP has taken into consideration the current environmental, license, and proposed permit requirements that the Project must meet.
- The capital costs for the Project, based on the information provided to us, appears to be on the low side of the expected range of costs we would expect. It should also be noted that a significant portion of the Project's costs are not fixed at this point and could be subject to labor and material shortages or price increases as we have seen in other coal plant developments throughout the United States. As such, we recommend a higher total capital cost be used in the R. W. Beck Sensitivity Case to see how a higher capital cost affects Project competitiveness.
- Overall engineering, procurement, construction, and commissioning efforts and scheduled durations and sequencing of these tasks appear adequate to support the overall schedule to complete the Project within 48 months after the start of construction.
- SME has identified the key permits and approvals required for the construction and operation of the Plant. While not all key permits and approvals have been obtained to date, SME is in the final stages of potentially acquiring such key permits and approvals including the NEPA approval from the RUS and the air quality permit from the MDEQ.

- The strategy of relying on existing Montana coal sources in competition with potential alternative sources of coal from a new Montana coal mine or mines in Wyoming is fundamentally sound and should result in SME obtaining the lowest cost sources of coal for the Project. Given the vast amount of coal reserves in and surrounding Montana, the availability of coal to the Project is not a critical concern. Generally, there is still a broad range of uncertainty surrounding the potential delivered cost of coal to the Project for specific mine options.
- The review of transmission issues does not raise specific transmission concerns relative to delivery of power from the Project.
- As described herein, under normal conditions and current expectations, the Project's busbar cost of power is expected to be competitive for a base load resource in the Pacific Northwest marketplace.
- ECPI currently is serving 20 to 25 MW of key account loads. Going forward ECPI will need to increase its key account customer base and undertake its internal planning to project future revenues, costs and financial criteria and goals. A significantly higher amount of power sales to key accounts will likely be required to support ECPI's acquisition interest to 25 percent of the Project.

Appendix A
KEY ASSUMPTIONS – BUSBAR FORECAST

Appendix A
KEY ASSUMPTIONS – BUSBAR FORECAST

The following presents the key assumptions used in the Busbar Cost of Power Forecast for the independent review of the proposed Project. The first table presents the values used in SME's current planning. The second table presents the alternative assumptions used in the R. W. Beck Sensitivity Case.

Table A-1
SME Inputs – Highwood Generating Station

Project Capital Cost including Interest During Construction	\$2,712 per kW
Interest Rate	5%
Capital Recovery Factor – 34 yrs	0.062755
Property Taxes and Insurance	1.54%
Escalation Rates:	
Fuel	1.00%
Fixed O&M	1.00%
Variable O&M	1.00%
Property Insurance	0.50%
Transmission O&M	1.00%
Total O&M Costs:	
Fixed	27.9 \$/kW/yr
Variable	2.711 \$/MWh
Transmission O&M	3.00%/transmission investment
Heat Rate	9836 Btu/kWhr
Fuel Cost:	
Cost of Fuel	8.5 \$/ton
Heating Value	9350 Btu/lb.
Cost per mmBtu	0.46 \$/mmBtu
Cost of Transportation	9 \$/ton
Transportation Cost per mmBtu	0.48 \$/mmBtu
Total Fuel Cost	0.94 \$/mmBtu
Capacity Factor	90%
SO_2 Emission Allowance Costs	\$640/ton (2011-2015) and \$254/Ton (2016-2044)

For the R. W. Beck Sensitivity Case, the following assumptions were revised:

- Fuel prices: The SME and Stanley fuel cost assumptions may reflect the forward-market prices at the moment, but the assumptions do not reflect the historical PRB coal prices. The coal forward market trading in the West is still very thin and, therefore, the posted forward prices may not be a good reflection of the majority of bilateral trades in the region. We suggested using coal prices that are reflective of the bilateral trading prices that have been seen in the region over the past few years.
- Escalation rates: At a 1 percent escalation rate, fuel and O&M prices are assumed to be lower in real terms over time. We suggested using the U.S. projected inflation rate (currently expected at 2.4 percent) to escalate fuel and O&M costs.
- Capacity factor: To reflect actual operation conditions at the start of the Project life, we suggest that the capacity be set at 85 percent in the first year of operation (2011), 87 percent in the second year, and 90 percent thereafter.
- SO_2 emission costs: No change is suggested.

Table A-2
R. W. Beck Alternative Assumptions

Item	
Plant Capital Cost including Interest During Construction	$2,880 per kW
"All in" base fuel cost	1.12 $/mmBtu
Fuel escalation rate, "All in"	2.4%
Fixed O&M escalation rate	2.4%
Variable O&M escalation rate	2.4%
Transmission O&M escalation rate	2.4%
Insurance, taxes, miscellaneous	2.4%
Variable O&M cost	5.89 $/MWh
Fixed O&M cost	40.53 $/KW-yr
Capacity factor – Year 1 (2011)	85%
Capacity factor – Year 2 (2012)	87%
Capacity factor – Year 3 and later	90%