Alaska Coal Gasification Feasibility Studies– Healy Coal-to-Liquids Plant

DOE/NETL-2007/1251

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Disclaimer

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NETL Contact:
Brent Sheets
Manager
Arctic Energy Office

Prepared by:
Lawrence Van Bibber
Charles Thomas
Robert Chaney
Research & Development Solutions, LLC (RDS)/
Science Applications International Corporation (SAIC)

National Energy Technology Laboratory
www.netl.doe.gov

Usibelli Coal Mine Operations

Healy, Alaska

The Usibelli Coal Mine, located in interior Alaska, is the site selected for studying the feasibility of siting a modest size Fischer-Tropsch (F-T) liquids production facility. This study focused on evaluating the feasibility of the gasification of Usibelli coal, Alaska's only operating mine, to produce F-T liquids to supply the niche markets of Alaska refineries.

ALASKA COAL GASIFICATION FEASIBILITY STUDIES
HEALY COAL-TO-LIQUIDS PLANT

EXECUTIVE SUMMARY

The Alaska Coal Gasification Feasibility Study entailed a two-phase analysis of the prospects for greater use of Alaska's abundant coal resources in industrial applications. Phase 1, *Beluga Coal Gasification Feasibility Study*,[1] assessed the feasibility of using gasification technology to convert the Agrium fertilizer plant in Nikiski, Alaska, from natural gas to coal feedstock. The Phase 1 analysis evaluated coals from the Beluga field near Anchorage and from the Usibelli Coal Mine near Healy, both of which are low in sulfur and high in moisture.

This study expands the results of Phase 1 by evaluating a similar sized gasification facility at the Usibelli Coal mine to supply Fischer-Tropsch (F-T) liquids to central Alaska. The plant considered in this study is small (14,640 barrels per day, bbl/d) compared to the recommended commercial size of 50,000 bbl/d for coal-to-liquid plants. The coal supply requirements for the Phase 1 analysis, four million tons per year, were assumed for the Phase 2 analysis to match the probable capacity of the Usibelli mining operations. Alaska refineries are of sufficient size to use all of the product, eliminating the need for F-T exports out of the state.

The unexpected curtailment of oil production from Prudhoe Bay in August 2006 highlighted the dependency of Alaskan refineries (with the exception of the Tesoro facility in Nikiski) on Alaska North Slope (ANS) crude. If the flow of oil from the North Slope declines, these refineries may not be able to meet the in-state needs for diesel, gasoline, and jet fuel. Additional reliable sources of essential fuel products would be beneficial.

Site Conditions

The Healy site under consideration is located on leased land about six miles north of Usibelli's current coal mining operations at Two Bull Ridge. A new mining operation near Jumbo Dome would be developed to supply coal to the facility. For a gasification and F-T plant sized to use four million tons per year of coal, the Jumbo Dome deposits would last for more than 50 years. Further, the site is three miles from the Alaska Intertie, enabling excess power to be marketed on the grid. Impoundments on Emma and Marguerite Creeks would provide process and cooling water.

Product Markets

Figure ES-1 summarizes the process inputs and outputs to the Healy Coal-to-Liquids Plant. The plant would produce 14,640 bbl/d of very low-sulfur liquid products per day, which could be used by in-state refineries as feedstocks or blending products to replace high-sulfur crude oil. Potential customers include the Flint Hills and PetroStar refineries in North Pole, the PetroStar refinery in Valdez, and the Tesoro refinery in Nikiski. The North Pole refineries can be supplied directly by rail, while the Nikiski and Valdez refineries would require a combination of rail and barge transport.

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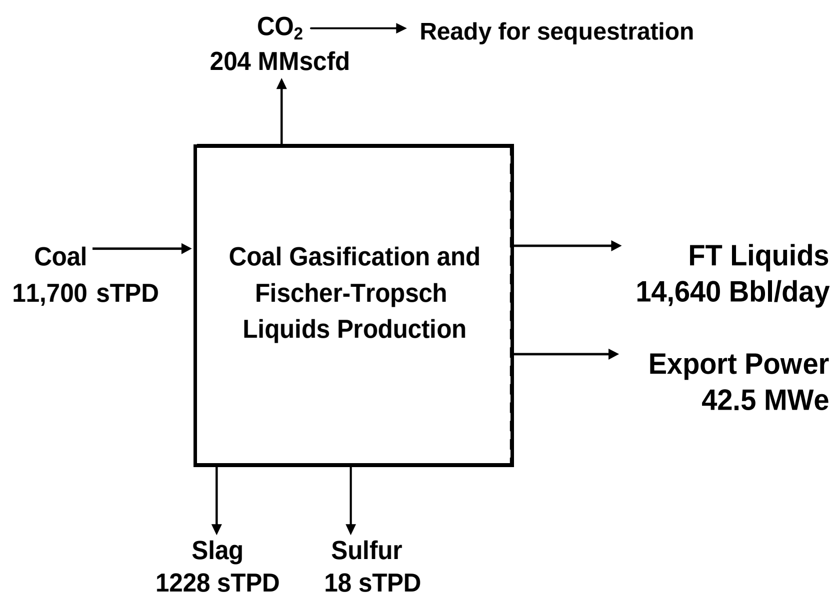
[1] Chaney, R.E. and L.E. Van Bibber, et al, RDS, "Beluga Coal Gasification Feasibility Study", Contract No. DE-AM26-04NT41817, Task 333.01.01, July 2006.

Plant by-products could also be marketed. Sulfur, separated from the process stream, is a commodity that could be sold into the export market. However, because the Alaskan market is limited, sulfur would be shipped by rail to a port and shipped to the lower 48 states or the Pacific Rim. Slag from the gasifiers is inert and non-toxic. While it is possible that some could be shipped via rail to the Anchorage area and used for road construction and aggregate, this study assumed that the slag would be used as backfill at the mine site.

Electric power represents another marketable by-product. Based on the proposed plant configuration, 42.5 MWe of power could be exported to the Alaskan market, which can absorb up to 70 MWe without major grid upgrades.

CO_2 can be vented or captured and sequestered in geologic formations such as saline aquifers or unmineable coal beds. If the Healy area coal beds are capable of economic coal bed natural gas (CBNG) production there may be added value for using CO_2 to improve recovery of CBNG.

Figure ES-1 Process Inputs and Outputs for the Healy F-T Plant



Plant Design

The Healy Coal-to-Liquids Gasification Plant is based on the same technology used in the *Beluga Coal Gasification Feasibility* study. Because of the change from producing hydrogen and CO_2 to a plant that produces Fisher-Tropsch liquids, the plant downstream from the gasifier has changed significantly.

CO_2 sequestration-ready plant design components:

1. Slurry-fed gasification using coal as feedstock.
2. 95% purity oxygen production using a cryogenic air separation unit (ASU)
3. Syngas cooling and slag removal at gasifier outlet
4. Syngas scrubbing for chlorides removal
5. Carbonyl sulfide (COS)+ Hydrogen Cyanide (HCN) hydrolysis
6. Mercury removal using activated carbon beds

7. Crystasulf acid gas removal with sulfur polisher
8. Fisher-Tropsch liquid fuels production including off-gas recycle and additional hydrotreating
9. Power production, with excess power exported to the grid

Additional plant components for implementing CO_2 sequestration

10. compressor (1500 psi)
11. pipeline to sequestration site
12. injection wells

The Healy Coal-to-Liquids Plant would use indigenous coal to produce the 14,600 bbl/day of F-T liquids for offsite shipment by rail. Alaskan refineries are of sufficient size to use all of the product, eliminating the need for F-T exports from the state. Estimated shipping costs to Alaskan refinery customers range from $2 to $6 per barrel depending on final destination.

The performance summary for the Healy coal-to-liquids plant for the base case and alternate case is shown in Table ES-1.

Economic Analysis

The economic analysis relied upon a financial model that has been used in numerous gasification studies, and is now the standard used by NETL for integrated gasification combined-cycle (IGCC) systems analysis. The model provides key metrics against which to gauge project viability, including return on equity investment (ROI), net present value (NPV), and parameter sensitivities.

The economic analysis used a 25% project contingency for all estimates. Other contingencies included a 9.8% process contingency for the F-T unit, 2% for start-up costs, and a 10% owner's cost. Based on a 30-year project life, a $2.27 billion total capital cost, and an 8% cost of capital, the required product gate price is $64/bbl to achieve a 12% return on investment (ROI). Adding the estimated shipping cost of $2 to $6 per barrel increased the required product gate price to $66 to $70 per barrel to maintain a 12% ROI. No provisions for tax or production incentives were considered in this study.

The ROI is highly dependant on the F-T product price. As shown in Figure ES-2, a modest $5/bbl drop in product value from $64/bbl to $59/bbl reduces ROI by 2%.

To gauge the investment potential for the Healy Coal-to-Liquids Plant, the value of the F-T liquids must be placed in context with the value of other petroleum products in the Alaskan market, such as crude oil, gasoline and diesel. Two different approaches were considered to estimate the F-T liquid product value:

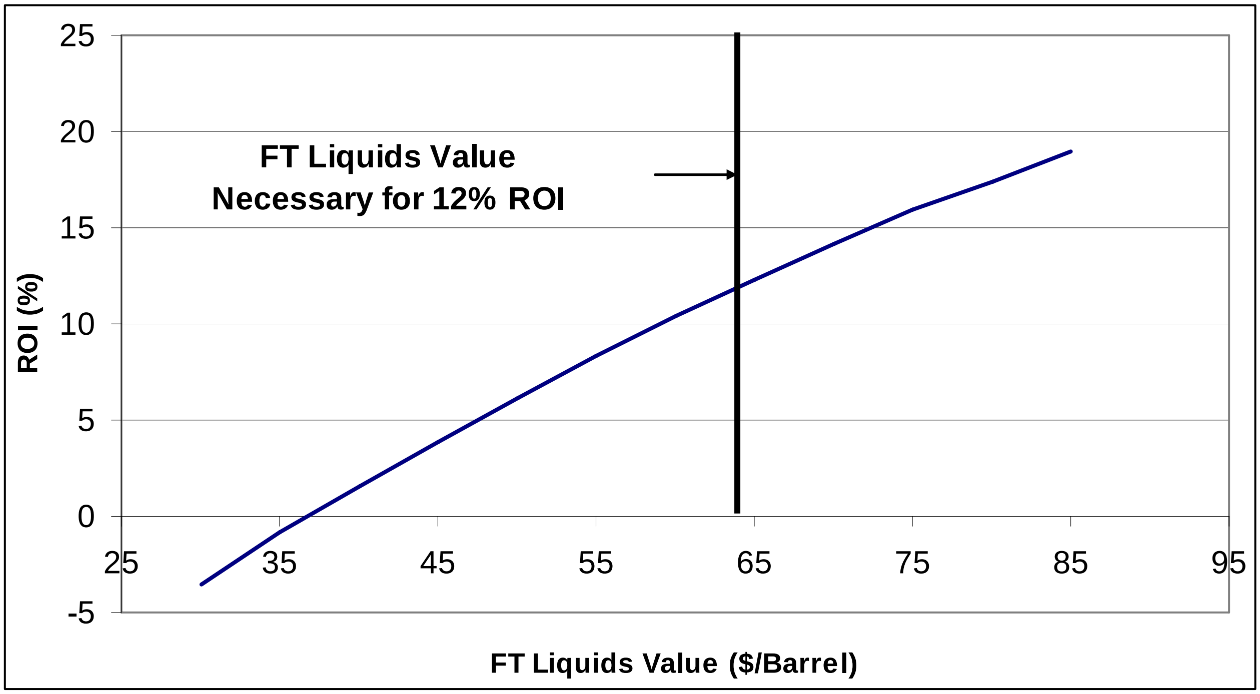
1. **F-T price relative to ANS crude (most conservative)**–As a conservative first estimate, the F-T liquids value necessary to achieve a 12% ROI can be directly compared to recent ANS crude values (in-state Alaska prices), with no premium added to account for the enhanced quality of the F-T liquids. This approach assumes the F-T product could displace ANS crude in the feedslate of local refiners. The average in-state ANS crude price is $57.11 over the 2005 to April 2007 time period.

Table ES-1 Healy Coal-to-Liquids Plant–Plant Performance Summary
E-Gas Gasifier, H/P ASU, LM2500 G/T

Plant Output		
Gas Turbine Power	57,720	kW_e
Steam Turbine Power	135,207	kW_e
Total	**192,927**	**kW_e**
F-T Liquids Production		
F-T Liquids Production	14,640	bbl/day
Auxiliary Load		
Coal Handling	180	kW_e
Coal Milling	4,550	kW_e
Coal Slurry Pumps	1,090	kW_e
Slag Handling and Dewatering	2,330	kW_e
Air Separation Unit Main Air Compressor	94,500	kW_e
Oxygen Compressor	18,650	kW_e
Fuel Gas Compressor	6,803	kW_e
Syngas Recycle Blower	1,701	kW_e
All F-T Processes	8,010	kW_e
Boiler Feedwater Pumps	2,525	kW_e
Condensate Pump	25	kW_e
Flash Bottoms Pump	386	kW_e
Circulating Water Pump	1,800	kW_e
Cooling Tower Fans	410	kW_e
Scrubber Pumps	400	kW_e
Gas Turbine Auxiliaries	2,000	kW_e
Steam Turbine Auxiliaries	1,000	kW_e
CrystaSulf Plant Auxiliaries	500	kW_e
Miscellaneous Balance-of-Plant	3,000	kW_e
Transformer Losses	560	kW_e
Total Net Auxiliary Load	**150,420**	**kW_e**
Plant Performance–CO_2Sequestration Ready		
Net Plant Power	42,507	kW_e
Net Plant Thermal Efficiency (HHV)	44.5%	
Coal Feed Flowrate	975,000	lb/hr
Thermal Input[1]	2,185,944	kW_t
Elemental Sulfur Production[2]	18.4	tons/day
Condenser Duty	434	MMBtu/hr
Plant Performance with CO_2 Sequestration		
Additional auxiliary load–CO_2 Compressor	26,000	kWe
Net plant power–Case 2	16,507	kWe
Net Plant Thermal Efficiency–Case 2	43.3%	

1 – HHV of as-fed Usibelli 27% moisture coal is 7,650 Btu/lb.
2 – Predicted based on 99.5% sulfur recovery in CrystaSulf unit.

Figure ES-2 Impact of F-T Liquids Value on Plant ROI

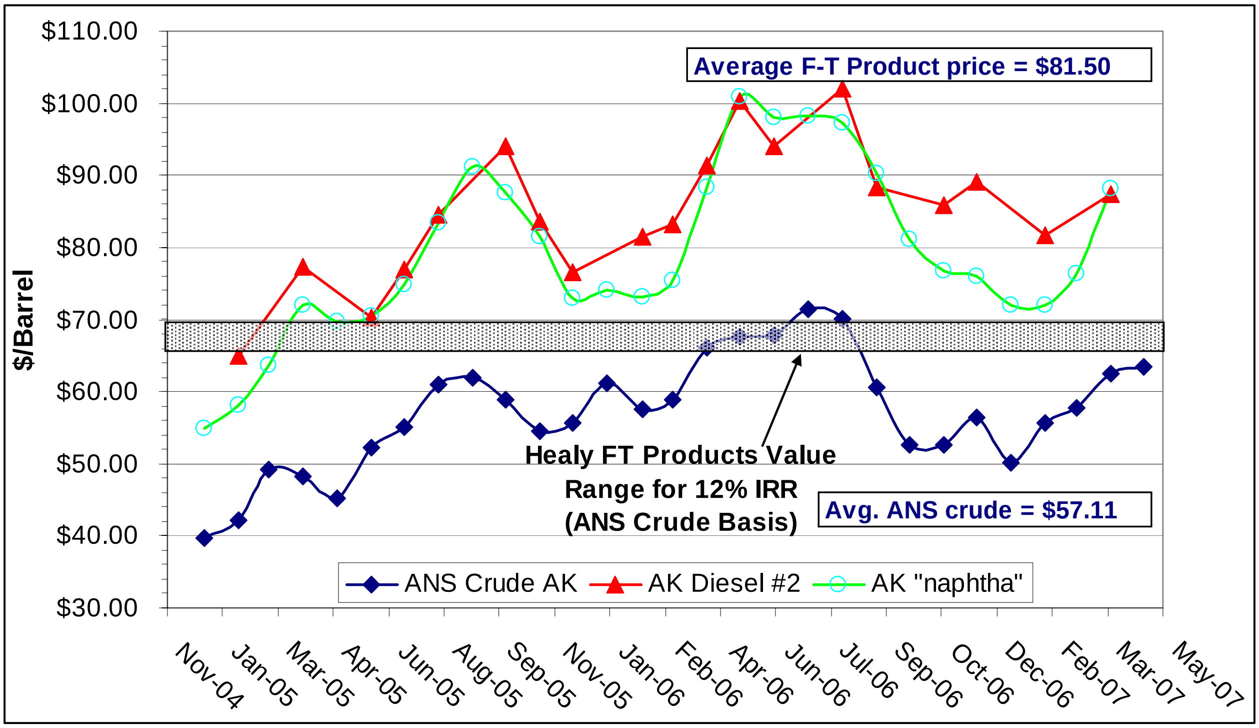


2. **F-T price relative to refined gasoline and diesel–**The raw F-T product contains both diesel and naphtha fractions that would need to be fractionated. The diesel portion of the F-T product can be blended directly with refinery diesel product without further refining and contains no sulfur, low aromatics, and has excellent diesel blending properties. The naphtha portion of the product will likely require additional upgrading in a refinery. Refiners would likely pay a premium for the F-T liquids relative to ANS crude. This premium was estimated by using average spot market values for diesel and naphtha in Alaska. The diesel in the F-T barrel was valued at spot diesel prices, while the F-T naphtha was valued at spot gasoline price minus 10 cents per gallon. Under this methodology, the F-T barrel would be worth about $81.50 per barrel ($1.94 per gallon). This is well above the hurdle rate of $66 to $70 necessary to meet the 12% ROI requirement.

It is not possible to determine the most likely price for the F-T product at this point. However, it should be bounded by ANS crude price (low) and Alaska refined products prices (high).

Figure ES-3 shows recent prices for ANS crude oil, diesel and naphtha in Alaska markets. The shaded region shows the F-T liquids value that must be obtained for the CO_2 Sequestration-ready project to meet a 12% ROI for equity participants. If the F-T liquids are compared directly to ANS crude (the bottom line in the graph), the project would likely be economic only if nominal crude prices remain high by historic standards. However, pricing the individual F-T fractions so they more closely represent finished product prices (the upper two lines in the graph) would make the project economic over a much wider range of potential market prices.

Figure ES-3 F-T Liquids Range for 12% ROI versus Spot Crude and Petroleum Product Values, 2005 to April 2007



Plant capital costs and plant availability also have a large impact on ROI. Capital costs are a major fraction of the overall cost of electricity. Availability impacts the magnitude of capital costs to levelized energy costs. A 25% swing in either of these variables could change the ROI by 5 to 6 percentage points. However, the expected value for the F-T liquids was determined to be of greater importance when estimating plant financial performance.

Additional costs for CO_2 capture and sequestration results in an F-T liquids gate value of $70/barrel for a 12% ROI, if the CO_2 had a value of $0/MSCF. But a value of $0.42/MSCF for CO_2 would maintain a 12% ROI if the gate value for F-T liquids was held at $64/barrel. Thus, the cost of implementing CO_2 sequestration adds approximately $6/barrel to the price of F-T liquids calculated as follows:

	$70/bbl for F-T liquids with CO_2 valued at $0/Mscf)
less	$64/bbl for F-T liquids with CO_2 valued at $0.42/Mscf)
=	$6/bbl incremental value for sequestration @ 12% ROI.

The CO_2 value of $0.42/MSCF is below that used for in the Phase 1 *Beluga Coal Gasification Feasibility Study* where CO_2 for enhanced oil recovery (EOR) in the Cook Inlet was valued at $0.50/MSCF. For the Healy CTL plant, it is likely that the CO_2 would be disposed of as a waste product because there are no oil fields or existing CBNG production in the vicinity.

Environmental Permits and Issues

An analysis of the current design basis indicates that a proposed gasification and F-T facility at the proposed project site is feasible in terms of current environmental permitting and compliance requirements imposed by federal and state regulations. Detailed environmental compliance strategies and mitigation measures would need to be developed in concert with design details and operational plans and would include features necessary for proximity to the Denali Wilderness, which is a Class 1 area.

Conclusions:

- The establishment of a 14,640 bbl/d F-T liquids plant using 4 million tons/year of coal is technically feasible at the Usibelli Mine. At a product price of $64/bbl, the return on investment will meet the 12% ROI goal.
- There is an in-state market for all of the liquid products from the plant. Alaskan refineries are of sufficient size to be able to use the entire product, thus eliminating the need for export from the state. Slag will primarily be used to backfill at the mine, but some may be sold as aggregate. Sulfur will be stockpiled and sold into the export market.
- Estimated shipping costs to customer refineries range from $2 to $6 per barrel, depending on final destination. This results in an estimated delivered product price of $66 to $70 per barrel for F-T liquids. This price is near the historical high of ANS crude. The value of diesel fuel and naphtha in Alaska was used to estimate an upper bound on the value of the F-T product. Looking at this product slate a bench mark product price of about $84 per barrel can be obtained, which would enhance the economics of this project to 19% ROI.
- Technically, un-mineable portions of the Usibelli coal fields provide a unique opportunity for sequestration. Economically, the cost of capture and sequestration is on the order of magnitude of $0.42/Mscf ($7/ton) and would reduce the ROI to 9.7%. However, there may be opportunities for enhanced recovery of natural gas from coal beds that could be investigated.
- There are no environmental permitting issues that appear to affect the feasibility of establishing the plant. Permits and permitting paths have been documented.

CONTRIBUTORS AND ACKNOWLEDGEMENTS

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Contributors

Steering Committee

Lisa Parker, Corporate Relations, Agrium U.S., Inc.

Tim Johnson, Technical Services, Agrium U.S., Inc.

Ron Miller, Executive Director, Alaska Industrial Development and Export Authority

Rick Fredericksen, Mining Section Chief, Alaska Department of Natural Resources

Linda Hay, Special Staff Assistant-Resources, Alaska Governor’s Office

Brad Janorschke, General Manager Homer Electric Assoc., Alaska Power Association

Robert Stiles, Mine Owner Representative, DRven

Steve Denton, Vice President, Business Development, Usibelli Coal Mine

Eric Yould, At-Large

Technical

Brent Sheets, Manager, AEO, DOE/NETL

James Hemsath, AEO, DOE/NETL

Larry Van Bibber, Subtask Manager, RDS/SAIC

Robert Chaney, Technical Project Manager, RDS/SAIC

Robert Dolence, RDS/Leonardo Technologies, Inc. (LTI)

Avanalist Jackson, RDS/LTI

Chris Munson, RDS/LTI

John Winslow, RDS/LTI

Erik Shuster, RDS/SAIC

Michael Nagy, RDS/ENTRIX

Sheldon Kramer, RDS/Nexant

Scott Olson, RDS/Nexant

Mike Rutkowski, RDS/Parsons

Howard McIlvried, RDS/SAIC

Charles Thomas, RDS/SAIC

Ralph Zarumba, RDS/SAIC

Steve Colt, UAA, ISER

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ACRONYMS AND ABBREVIATIONS

ACMCRA	Alaska Surface Coal Mining Control and Reclamation Act
ADEC	Alaska Department of Environmental Conservation
ADF&G	Alaska Department of Fish and Game
ADNR	Alaska Department of Natural Resources
AFBC	Atmospheric fluidized-bed combustion
AFDC	Allowance for funds used during construction
AGR	Acid gas removal
ANS	Alaska North Slope
ASU	Air separation unit
bbl	barrel (42 gallons)
bbl/day	barrels per day
bbl/yr	barrels per year
BGL	British Gas Lurgi
Btu	British thermal unit
CBNG	Coal bed natural gas
CCT	Clean coal technology
CDR	Carbon dioxide recovery
cfm	Cubic feet per minute
CF	Capacity factor
CO_2	Carbon dioxide
COE	Cost of electricity
COS	Carbonyl sulfide
COE	Cost of electricity
CS	Carbon steel
CT	Combustion turbine
CTL	Coal-to-Liquids
CWT	Cold water temperature
dB	Decibel
DCS	Distributed control system
DOE	Department of Energy
EPA	Environmental Protection Agency
EPC	Engineering, procurement, and construction

EPRI	Electric Power Research Institute
ESP	Electrostatic precipitator
ETE	Effective thermal efficiency
FBHE	Fluidized-bed heat exchanger
FD	Forced draft
FGD	Flue gas desulfurization
FOAK	First of a kind
FRP	Fiberglass-reinforced plastic
F-T	Fischer-Tropsch
gpm	Gallons per minute
GJ	Gigajoule
GT	Gas turbine
hr	Hour
H_2	Hydrogen
H_2SO_4	Sulfuric acid
HAP	Hazardous air pollutant
HCl	Hydrochloric acid
HCN	Hydrogen Cyanide
HDPE	High density polyethylene
HHV	Higher heating value
hp	Horsepower
HP	High pressure
HRSG	Heat recovery steam generator
HVAC	Heating, ventilating, and air conditioning
HWT	Hot water temperature
Hz	Hertz
in. H_2O	Inches water
in. Hga	Inches mercury (absolute pressure)
in. W.C.	Inches water column
ID	Induced draft
IGCC	Integrated gasification combined cycle
IP	Intermediate pressure
ISO	International Standards Organization

ITM	Ion transfer membrane
KBR	Kellogg, Brown and Root, a subsidiary of Halliburton
KNO	Agrium Kenai Nitrogen Operations
kPa	Kilopascal absolute
kV	Kilovolt
kW	Kilowatt
kWe	Kilowatts electric
kWh	Kilowatt-hour
kWt	Kilowatts thermal
LAER	Lowest achievable emission rate
lb/ft^2	Pounds/square foot
LCOE	Levelized cost of electricity
LASH	Limestone ash
LHV	Lower heating value
LP	Low pressure
MAF	Moisture and ash free
MCR	Maximum coal burning rate
MDEA	Methyldiethanolamine
MEA	Monoethanolamine
MHz	Megahertz
MLLW	Mean lower low water
MMBtu	Million British thermal units (also shown as 10^6 Btu)
MMSCFD	Million standard cubic feet per day (also shown as 10^6 sfcd)
MPa	Megapascals absolute
MSCF	Thousand standard cubic feet per day
MSL	Mean sea level
MWe	Megawatts electric
MWh	Megawatts-hour
MWt	Megawatts thermal
NETL	National Energy Technology Laboratory
N/A	Not applicable
NAAQS	National Ambient Air Quality Standards
NGCC	Natural gas combined cycle

NM^3	Normal cubic meter
NOx	Oxides of nitrogen
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
O&M	Operations and maintenance
OP/VWO	Over pressure/valve wide open
OTR	Ozone transport region
PA	Primary air
PC	Pulverized coal
PFD	Process flow diagram
ppb	Parts per billion
pph	Pounds per hour
ppm	Parts per million
ppmv	Parts per million volume
ppmvd	Parts per million volume, dry
PRB	Powder River Basin coal region
PSA	Pressure swing adsorption
psia	Pounds per square inch differential
psig	Pounds per square inch gage
RDS	Research and Development Solutions, LLC
rpm	Revolutions per minute
SC	Supercritical
SCFD	Standard cubic feet per day
scfm	Standard cubic feet per minute
scmh	Standard cubic meter per hour
SCR	Selective catalytic reduction
SMR	Steam methane reformer
SNCR	Selective non-catalytic reduction
SNG	Synthetic natural gas
SO_2	Sulfur dioxide
SoCo	Southern Company
SOFC	Solid oxide fuel cell
SPCC	Spill Prevention and Countermeasure

SS	Stainless steel
TAG	Technical Assessment Guide
ST	Steam turbine
TCR	Total capital requirement
TGTU	Tail gas treating unit
TPC	Total plant capital (cost)
THGD	Transport hot gas desulfurizer
TPC	Total plant cost
TPD	Tons per day
ph	Tons per hour
TPI	Total plant investment
Ton	short ton (2000 pounds)
Tonne	Metric ton (1,000 kilograms or 2,204.62 pounds)
USACE	U.S. Army Corp of Engineers
US DOT	U.S. Department of Transportation
V-L	Vapor liquid portion of stream (excluding solids)
WB	Wet bulb
wt%	Weight percent

1. INTRODUCTION

The objective of this study was to determine the economic feasibility of siting a coal-to-liquids (CTL) plant in the central region of Alaska, specifically near the community of Healy. The Healy CTL plant would use coal from the Usibelli Coal Mine located nearby to co-produce electric power and Fischer-Tropsch liquids (F-T) for local use or for sale in domestic or foreign markets or both.

This is the second study aimed at assessing the feasibility for coal gasification technology for use in Alaska. The first study, *Beluga Coal Gasification Feasibility Study*,[2] focused on determining the feasibility of locating a coal-to-syngas plant at the current Agrium Nitrogen Operations plant site near Kenai, Alaska, for providing feedstock to replace the natural gas currently used. Agrium, faced with the increasing cost and reduced availability of natural gas, is internally investigating the use of coal feedstock as a replacement for natural gas. Agrium's "Blue Sky" concept includes gasification and a separate power plant, but is not an IGCC design[3] as assumed in the NETL study.

The *Beluga Coal Gasification Feasibility Study* considered all aspects of the installation and infrastructure, including: coal supply and cost, coal transport costs, delivery routes, feedstock production for fertilizer manufacture, plant steam and power, CO_2 uses, markets for possible additional products, and environmental permit requirements. Based on the chosen assumptions, conversion of the Agrium plant was technically and economically feasible, with an internal rate of return of 11.1%.

This study expands on the Beluga coal gasification analysis by optimizing the plant design for F-T liquids production and power requirements.

An earlier NETL study, DE-FC26-01NT41099 (Task 8) by ICRC[4] determined that two of the best sites for a CTL plant are mine-mouth plants at the Beluga Coal field (Chuitna Mine) and at the Usibelli Mine. That study investigated only a plant producing F-T fuels, acknowledging that power could also be produced, but did not investigate co-production of power and coal-derived liquids.

1.1 Background

The Usibelli Mine is the only operating coal mine in Alaska. There is a mine-mouth power plant (Healy #1) operated by Golden Valley Electric that currently purchases Usibelli coal. The mine has been in service for more than 60 years. Its location adjacent to the Alaska Railroad enables coal shipment via rail to interior Alaska and to the Seward coal terminal for export. The mine has leases for sufficient coal for extensive further mine development. The Usibelli Coal Mine has actively investigated opportunities to expand the use of coal from their mine:

- The dormant DOE Healy Clean Coal Demonstration project was built adjacent to Healy #1 to demonstrate clean coal technology.

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[2] Chaney, R.E. and L.E. Van Bibber, et al, RDS, "Beluga Coal Gasification Feasibility Study", Contract No. DE-AM26-04NT41817, Task 333.01.01, July 2006.
[3] Agrium - Petroleum News, Vol. 11, No. 37 Week of September 10, 2006
[4] ICRC *et al*, DE-FC26-01NT41099 (Task 8)

- The Usibelli Coal Company was involved in the coal slurry project at the University of Alaska Fairbanks.
- One recent study was for the proposed Emma Creek Power Plant to produce 200 MW for sale into the railbelt electric grid.

The Emma Creek project site has extensive coal deposits under lease, sufficient access to water, is within three miles of the Railbelt power lines, and has access to rail for product shipping. It was the Emma Creek site that encouraged selection of Healy as the site for this study. Additional details on mine and plant site are provided in Sections 2 and 3.

1.2 Project Scope

This report is organized into seven sections:

1. Introduction–Project overview and scope
2. Coal Supply and Project Site–coal supply and quality, site location and features
3. Market Analysis–F-T liquid markets in Alaska
4. Plant Technology and Plant Design–design basis, design, operating characteristics, and capital cost estimates
5. Financial Analysis–production cost estimates, internal rate of return, and sensitivities
6. Environmental Permitting and Issues–cataloging of permits and responsible agencies
7. Summary and Conclusions

2. COAL SUPPLY AND PROJECT SITE

2.1 Alaskan Coal Fields

Alaska has 3.7 trillion tonnes (metric tons) of hypothetical coal resources, found predominantly in three regions. The Northwest region (Northern Alaska Basin) primarily contains bituminous coal (with smaller amounts of sub-bituminous and lignite coal), while the Central Interior (Nenana Province) and South Central (Cook Inlet-Susitna Basin) regions primarily contain sub-bituminous coal with relatively high ash content and very low sulfur content. Table 2.1[5] summarizes the Hypothetical Resources,[6] Identified Resources,[7] and Measured Resources.[8]

Table 2-1 Alaska Coal Resources[9,10]

	Hypothetical Resources (million tonnes)	Identified Resources (million tonnes)	Measured Resources (million tonnes)
Northern Alaska Basin	3,630,000	136,100	73
Nenana Province	13,320	7,800	227
Cook Inlet-Susitna Basin	64,230	10,550	1,400
All Other Areas	8,660	520	0
Alaska Total	3,716,210	154,970	1,700

2.2 Usibelli Coal Mine

Founded in 1943 by Emil Usibelli, the Usibelli Coal Mine (UCM) is located in the Alaska Range, near the town of Healy. Currently, the only coal-producing mine in Alaska, UCM has a work force of about 85 and operates year-round.

Over its 63 years of operation, mine production has grown from 10,000 tons per year to an average 1.5 million tons of coal per year supported by the most modern mining equipment and state-of-the-art engineering. Today, UCM supplies six interior Alaska power plants with coal.

2.2.1 Setting

Usibelli Coal Mine Headquarters are located approximately two miles northeast of Healy, Alaska, in the Hoseanna Creek drainage district of interior Alaska. This is about 12 miles north

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5 DOE/EIA-0529(97), Glossary, U.S. Coal Reserves: 1997 Update, February 1999.

6 Hypothetical Resources - Undiscovered coal resources in beds that may reasonably be expected to exist in known mining districts under known geologic conditions.

7 Identified Resources - Specific bodies of coal whose location, rank, quality, and quantity are known from geologic evidence supported by engineering measurements.

8 Measured Resources - Coal for which estimates of the rank, quality, and quantity have been computed, within a high degree of geologic assurance, from sample analyses and measurements from closely spaced and geologically well known sample sites.

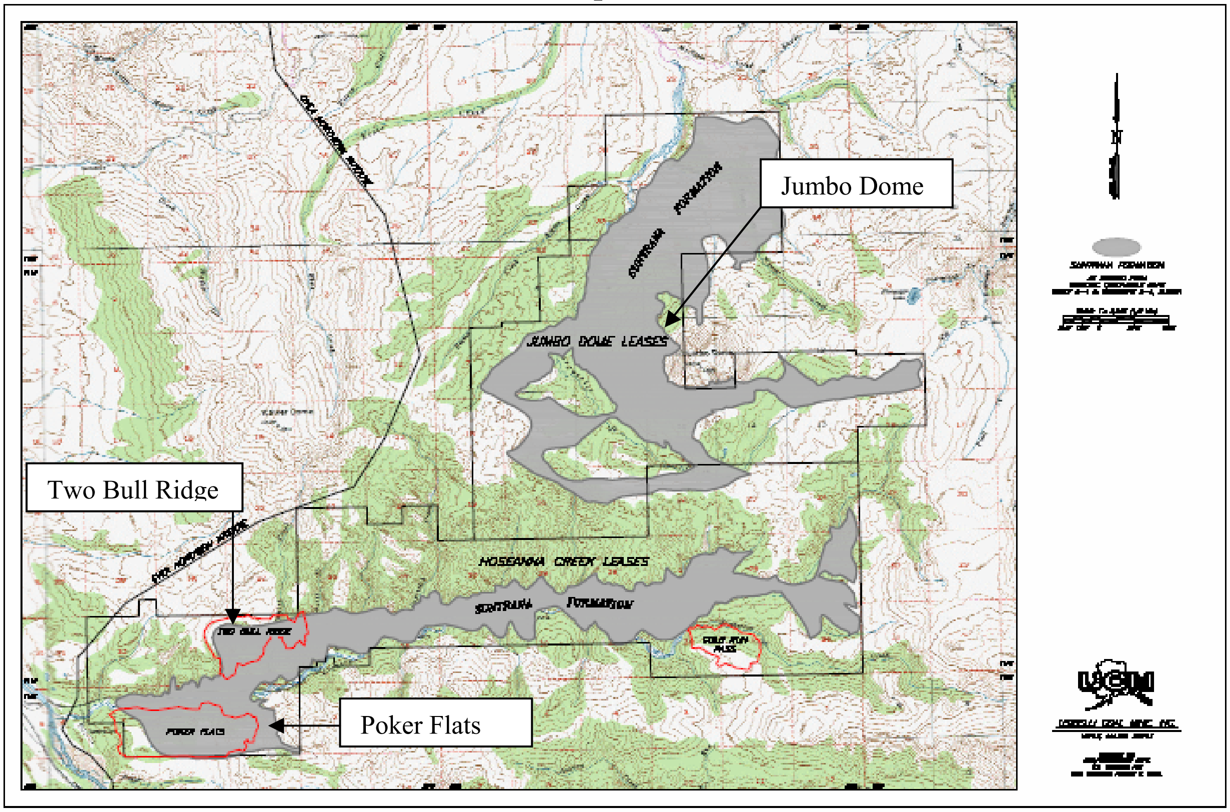
9 Resources - Naturally occurring concentrations or deposits of coal in the earth's crust, in such forms and amounts that economic extraction is currently or potentially feasible.

10 Stiles, R. B., DRven, "Alaska Coal Resources, Projects & Infrastructure, June 1998."

of the entrance to Denali National Park, 242 miles from Anchorage and 105 miles from Fairbanks.

Figure 2.1 shows a topographical map of the area with the Suntrana Formation illustrated. In the lower left (southwest corner) the Poker Flats area is shown. It has been mined and is now under reclamation. The Two Bull Ridge area, just north of Poker Flats, is now being mined. The quoted reserves for Usibelli include the area around the Hoseanna Creek deposits.

Figure 2-1 Map showing location of Usibelli's current mining areas and Jumbo Dome deposits



The Usibelli Coal Mine is in the Nenana Province. An estimated 227 million tonnes of in-place surface mineable coal exist at Usibelli, as shown in Table 2.2. The 91 million tonnes of proven reserves are more than sufficient to sustain current production levels if selected as the source. At about 2 million tonnes per year production, the Usibelli Mine has permits to continue production for more than 22 years, with more coal available in the future.

Table 2-2 Coal Reserves at the Usibelli Mine[11]

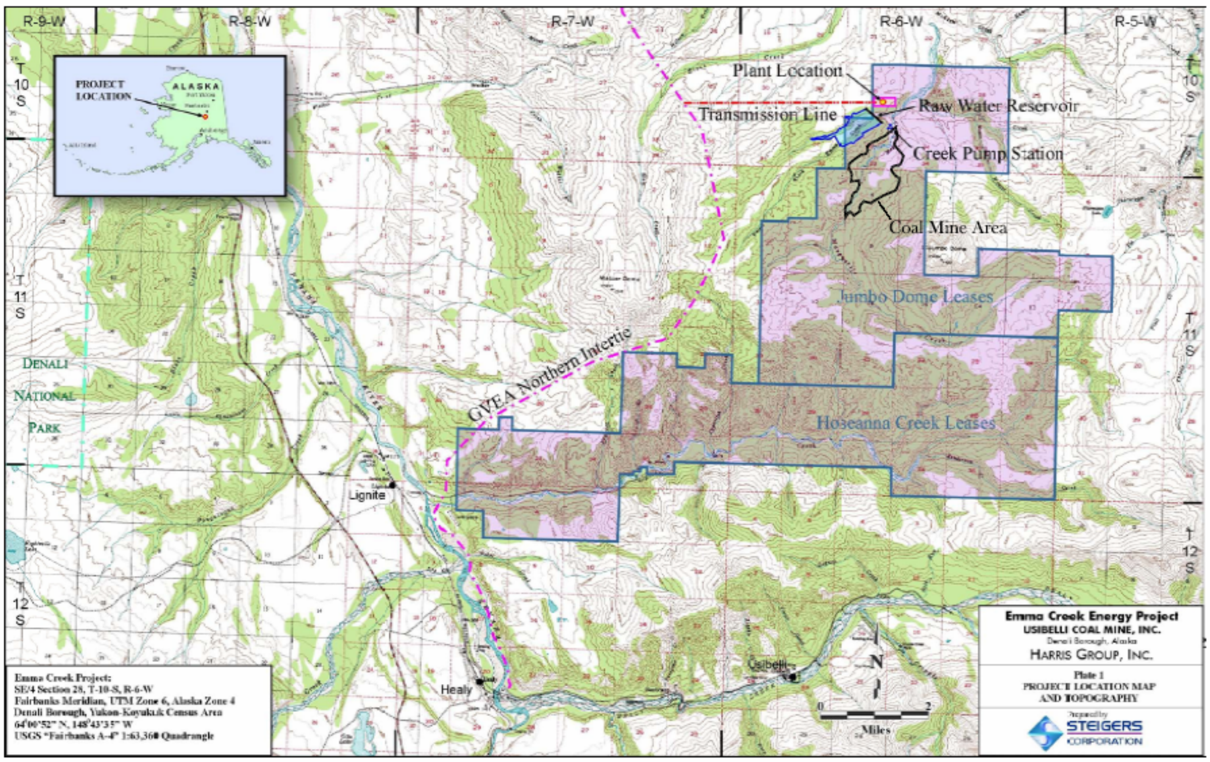
USIBELLI COAL MINE	Indicated Reserves (million tonnes)	Proven Reserves (million tonnes)	Permitted for Mining (million tonnes)
	227	91	45.5

[11] Usibelli web site (www.usibelli.com), 2005

2.2.2 The Healy Coal-to-Liquids Project Site

The proposed site for the Healy Coal-to-Liquids Plant is located about four miles north of the Hoseanna Creek mining area. The leases are in the Jumbo Dome region, as shown in Figure 2.2.

Figure 2-2 Map showing location of Usibelli's Jumbo Dome leases and the project site

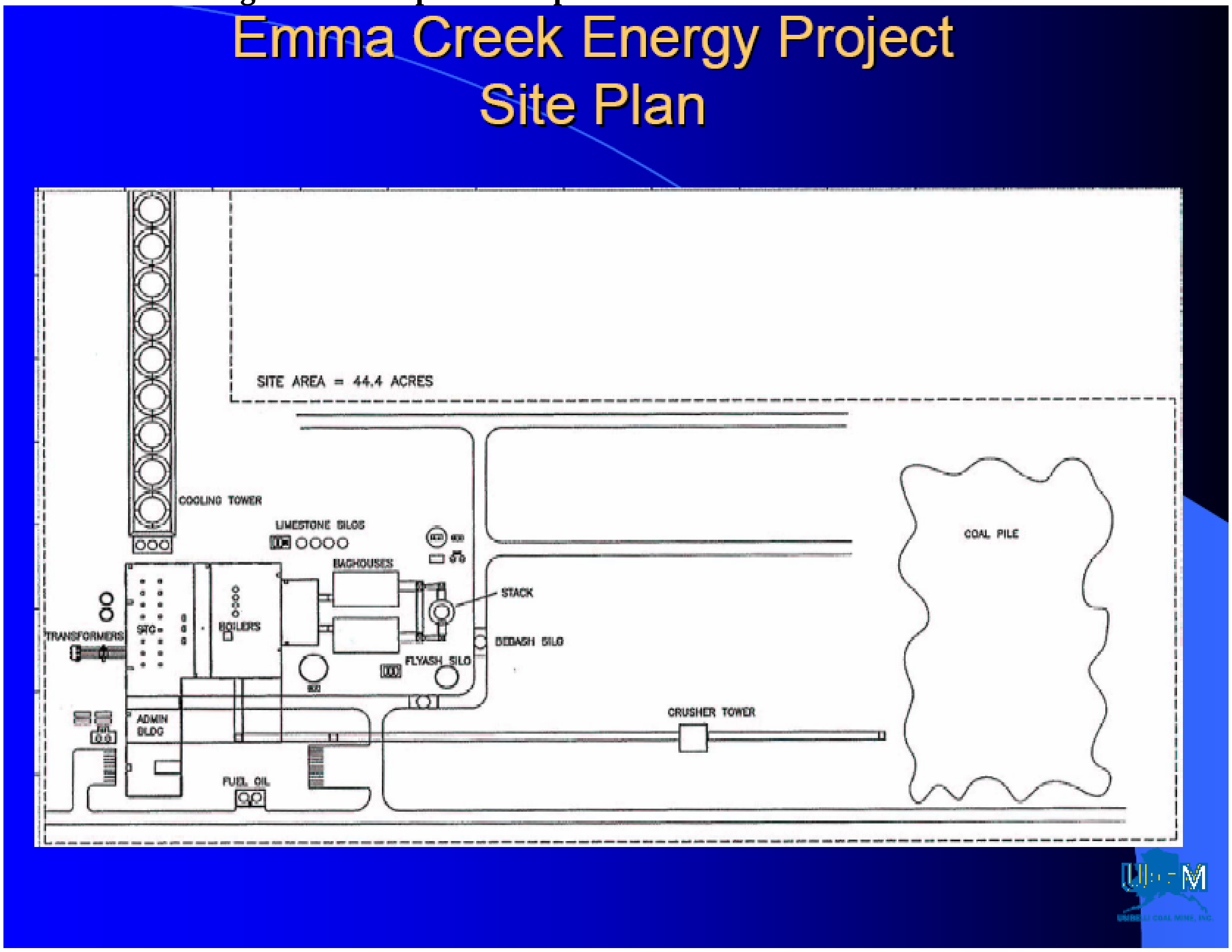


In 2004, Usibelli proposed construction of a 200 MW coal power plant at the north end of the Jumbo Dome mine area known as the Emma Creek Power Plant. The coal seams are extensions of the seams currently mined at Hoseanna Creek, which dip down and then resurface near Jumbo Dome. Seams #3 and #4 are 40 feet and 25 feet thick, respectively, as verified by trenching and exploration drilling.

The site is three miles from the main Railbelt grid power line. The plant would occupy about 45 acres, with water available from Emma and Marguerite Creeks, as shown in Figure 2.2. Sufficient coal exists in the Jumbo Dome deposits to operate the 200 MW plant for more than 50 years. If an F-T plant were pursued, further delineation of the deposits would be required, along with a detailed mine plan.

Figure 2.3 schematically illustrates the conceptual lay-out of the Emma Creek Power Plant. This could serve as the point of departure for more detailed site planning for the Healy Coal-to-Liquids plant.

Figure 2-3 Proposed site plan for Emma Creek Power Plant



2.2.3 Coal Properties

The properties of the Usibelli coal are given in Tables 2.3 and 2.4. It is a high-moisture sub-bituminous coal with low sulfur content.

Table 2-3 Properties of Usibelli Coals in Currently Mined Areas[12]

Proximate Analysis	Moist (As–Received) (%)
Moisture	27.0
Ash	8.0
Volatile Matter	36.0
Fixed Carbon	29.0
TOTAL	100.0
Ultimate Analysis	**Without moisture or ash**
Carbon	69.5
Hydrogen	4.5
Nitrogen	0.9
Chlorine	- -
Oxygen	24.8
Sulfur	0.3
TOTAL	100.0
Heating Value (Btu/lb)	7,800

Table 2-4 Properties coal from the Jumbo Dome Deposit

	Seam #3	Seam #4	Current Typical
Thickness	27.5 ft	38 ft	15-25 ft
Heating Value	7,666 Btu/lb	8,034 Btu/lb	7,800 Btu/lb
Moisture	28%	28%	26%
Ash	9.10%	4.60%	9%
Sulfur	0.14%	0.12%	0.17%

2.2.4 Delivered Cost of Coal

Based on discussions with the mine owners,[13] the mine mouth price for coal from Jumbo Dome at the Emma Creek site is estimated to be in the range of \$1.00/MMBtu. This correlates with \$15.60 per ton.

[12] http://www.usibelli.com/specs.html
[13] Steve Denton, private communication, June 16, 2006.

3. MARKET ANALYSIS

3.1 Introduction

Alaska's dependency on diesel fuels for transportation and energy makes it the ideal market for F-T blended fuels. The proposed plant at the Healy mine, sized to use 4 million tons per year of coal, could supply approximately 14,640 bbl/day of F-T liquids, a blend of naphtha, kerosene and diesel, to Alaska's refineries. This will be processed into (or blended with) distillate fuels and oils for distribution throughout Alaska. In addition to the F-T liquids, the plant will have two major marketable by-products–slag and sulfur. The latter of the two may prove to be difficult to sell due to logistics. The market for F-T liquids is expected to be strong due to the future low-sulfur specifications of gasoline and diesel and the anticipated growth of diesel-fueled passenger vehicle use.

This section looks at potential markets for the products and by-products of a coal-to-liquids plant including not only the partially refined liquids but also sulfur and slag. Market sectors that were evaluated include Alaska refineries, military bases, the electric power market and product shipping for offshore applications.

3.2 Fischer-Tropsch Applicability in Alaska

At 6 million barrels/year, Alaska ranks 50th in U.S. gasoline consumption. It is the only state whose distillate fuel consumption, 10 million barrel/year, dwarfs that of its gasoline consumption.[14] Distillate fuel oil is a general classification for one of the petroleum fractions produced in conventional distillation operations. It includes diesel fuels and fuel oils. Products referred to as Numbers 1, 2 and 4 diesel fuel are used in on- and off-highway applications such as trucks, automobiles, railroad locomotives and agricultural machinery. It is common practice to refer to fuel oil number 1 as kerosene. In Alaska, numbers 1, 2, and 4 fuel oils are used primarily for space heating and electric power generation.

Table 3-1 End Use in Alaska

End Use (barrels in thousands)	2003	2004
Distillate Fuel Oil		
• Residential	1,520	1,680
• Commercial	960	1,160
• Industrial	1,080	1,060
• Utilities	2,600	2,000
• Transportation	4,770	8,300
• Other	300	430
Kerosene	15	20
Jet Fuel (Kerosene Type)	19,881	22,270
Total Consumption	30,856	36,920

EIA, Alaska Distillate Fuel Oil and Kerosene Sales by End Use, 2005

The U.S. Environmental Protection Agency (EPA) mandated that the Alaska Ultra Low Sulfur Diesel (ULSD) rule takes full effect in 2010. The rule implements requirements for sulfur,

[14] EIA, 2006

cetane, and aromatics for highway, non-road, locomotive and marine diesel fuel used in the rural areas of Alaska.[15] The use of F-T feed/blend stock will help Alaska refineries comply with the more stringent specifications for their final products since it is a cleaner liquid than conventional fuel oils.

Whereas urban Alaskan residents rely primarily on natural gas for heat and electricity, rural residents use distillate fuel oils, such as kerosene, in their homes for space heating, water heating, lighting, refrigeration, cooking and running appliances. Rural utilities also deliver electricity produced from fuel oils to heat and provide energy for rural homes and communities.

In Alaska's industrial, commercial, manufacturing and mining sectors, distillate fuel oil is used for process heating and cooling, powering machinery, facility heating and electricity production. These fuels are also used in industrial and commercial heavy duty off- highway vehicles and construction equipment.

A sizeable portion of the Alaska population relies on diesel-fueled passenger vehicles, including trucks and busses. Another distillate, bunkering fuel, is used in commercial and private sea vessels and is just a small portion of Alaska's distillate consumption.

Sixty-four percent (64%) of Alaska's total distillate fuel consumption is attributed to jet fuel (kerosene type). Consumers include the commercial, industrial, and private sectors.

3.3 Fischer-Tropsch Products

The F-T process results in the following marketable products: F-T liquids, slag, and sulfur.

3.3.1 Liquids

In the coal-based F-T process, coal is first gasified to produce synthesis gas (carbon monoxide and hydrogen) that has been cleaned to remove sulfur and other impurities. The clean synthesis gas is then catalytically converted to zero-sulfur liquids that fall mainly within the diesel fuel boiling range. This diesel fuel fraction can be readily upgraded to produce premium high performance, low emission fuels for air, land and marine applications. These F-T fuels are superior to their conventional petroleum counterparts in both end-use and environmental properties. Specifically, the fuels have a high cetane number that provides for more efficient combustion. This attribute, in combination with the lack of sulfur and nitrogen species, results in significantly lower emissions of PM (particulate matter), NOx (nitrogen oxides), HC (hydrocarbon) and CO (carbon monoxide). The emission performance from F-T fuel use typically meets or exceeds all current and anticipated government fuel specifications (e.g., EPA 2006 Low Sulfur Fuels). The remaining lower-boiling range naphtha fraction can serve as a feedstock for chemicals and gasoline production or the naphtha can be reformed to produce hydrogen. Refer to Tables 3.2 and 3.3 for current and future gasoline/diesel specifications.

[15] Alaska Department of Environmental Conservation, "Area Sources Group–Ultra Low Sulfur Diesel," May 4, 2006.

Table 3-2 Global Gasoline/Diesel Specification

Country	2005 (ppm)	Future (ppm)	Date
United States	500	15	2006
European Union	50	10	2008
Australia	500	30	2008
Hong Kong	500	50	2006
Japan	50	10	2009
Republic of Korea	300	50	2006

Markets for GTL Products, Petroleum Economist, March 2003

Table 3-3 Comparison of Conventional and F-T Diesel Specifications

	U.S. Diesel (2006)	European Union Diesel (2005)	F-T Diesel
Sulfur, max (ppm)	15	50	0
Density, max (kg/cm)	850[16]	845	790
Cetane, min	40	51	75
Polyaromatics, max (vol %)	35	11	0
T95, max (C)	(T90) 338	360	345

Markets for GTL Products, Petroleum Economist, March 2003
Fueling U.S. Light Duty Diesel Vehicles, ConocoPhillips, August 2005

3.3.2 Slag

Slag is an inert, solid by-product of the coal gasification process and subsequently, a by-product in producing F-T liquids from coal. Slag is sold into many different markets depending on how it is processed. A particularly high end use of the aggregate slag is as a partial substitute for expanded perlite, which commands prices in the $150 per ton range. However, the major slag market is as a substitute for light-weight aggregate in the production of cement and concrete.

Molten slag that is water quenched creates a vitreous, non-leachable "glassy" particulate that can be granulated and used as blasting grit, for roofing tiles and for other building products. Air cooled slag is sold nationally at approximately $15.50/ton. In local Alaskan markets, slag is sold at approximately $20/ton.[17] Total Alaska demand is 5.7 million tonnes/yr for concrete aggregate, fill, road base covering and snow/ice control

Other markets for slag include:

- Concrete aggregate
- road construction aggregate,
- structural fill materials,
- land fill cover,
- anti-skid materials for roads and highways
- blasting grit, roofing tiles and other building lower grade slag requirements

[16] The U.S. does not specify a maximum or minimum density for diesel fuels, 850 kg/m^3 is the average density of U.S. diesel.
[17] McKinnon, John, Deputy Commissioner of Transportation and Public Facilities, personal communication

3.3.3 Sulfur

Sulfur is an intrinsic component of all coals. In the gasification process, sulfur is removed from the raw synthesis gas predominantly in the form of hydrogen sulfide (H_2S). If plant engineering and economic analyses determine a need for elemental sulfur recovery, a process step would be added to the plant configuration. For example, the widely-used Claus process reacts oxygen with H_2S to form pure sulfur. There are several other mechanisms of sulfur recovery that are described in the technical and systems sections of this study.

Elemental sulfur is a product of value. The pricing of sulfur is impacted by regional demand and proximity to markets. Uses of elemental sulfur include the making of:

- pulp and paper
- petroleum refining
- agricultural chemicals
- medicines
- phosphatic fertilizers
- electrical insulation
- vulcanizing rubber, and
- sulfuric acid

Sulfuric acid is used world-wide in the fertilizer and manufacturing industrial sectors. Because sulfuric acid is required to manufacture many essential products, its position has been retained as the most universally used mineral acid and the most produced and consumed inorganic chemical by volume. The value-added end products include:

- fertilizer
- ammonium sulfate
- super phosphate
- hydrochloric acid
- nitric acid
- sulfate salts
- synthetic detergents
- dyes and pigments
- explosives
- pharmaceuticals
- petroleum products from refining

3.4 Refinery Market Segment

There are six refineries in Alaska, but there are only four that produce petroleum products for consumer markets as shown in Table 3-4. BP and ConocoPhillips have refineries on Alaska's

North Slope to supply the oil field operational needs. Three of the four Alaska petroleum consumer product refineries are topping facilities, that is, a plant that removes only the lightest fractions from crude oil. Absent a cracking facility, these plants can only process carbon chains containing no more than 19 carbon atoms (C_{19}). The Tesoro facility at Nikiski is the only full refinery in the state and it processes beyond middle distillates that include up to 24 carbon atom chains (C_{24}). Therefore, any coal-to-liquids (CTL) facility would need to ensure the F-T product meets the minimum specifications for the respective refiner. This may require the CTL plant to perform product upgrading; i.e., partial refining.

Table 3-4 Consumer product refineries in Alaska and the assumed amounts of F-T liquids they may use

Location	Refinery	Capacity (bbl/day)	Assumed F-T Volume (bbl/day)	Type of Refinery
North Pole	Petro Star	17,000	4,200	Topping plant
Valdez	Petro Star	48,000	9,800	Topping plant
North Pole	Flint Hills	210,000	14,000	Topping plant
Nikiski	Tesoro	72,000	14,000	Full refinery

EIA, U.S. Refineries Operable Atmospheric Crude Oil Distillation Capacity, January 2005

Flint Hills Resources (FHR), Alaska's largest refinery, processes approximately 210,000 bbl/day of North Slope crude oil. Products include gasoline, jet fuel, heating oil, diesel, gas oil and asphalt. These products are distributed locally, along Alaska's coastline, in the far eastern areas of the state, and internationally to the Republic of Korea and Japan via two terminals in Anchorage and Fairbanks. FHR also delivers fuel to airline customers, fueling 18 to 24 flights per day.

Petro Star Inc. processes approximately 65,000 bbl/day of North Slope crude oil at refineries in Valdez and North Pole, Alaska. They supply rural communities throughout interior and northern Alaska, Anchorage Airport, Alyeska Pipeline, and the US Army and Air Force bases. Products include military and commercial jet fuel, kerosene, diesel, heating oil and marine diesel.

Both FHR and Petro Star are topping facilities, stripping the light products from the Alyeska Pipeline's North Slope crude. The unused crude, heavier petroleum that cannot be processed in these refineries, is returned to the pipeline with a payment made based on the material removed by the refineries. In this study it is assumed that the current practice is continued. The low quality (low octane) of the F-T naphtha may degrade the returned crude. Therefore, this assumption must be verified in any follow-on analysis.

The Tesoro Petroleum refinery, located in the Kenai Peninsula, processes approximately 72,000 bbl/day of crude oil from the Cook Inlet and Alaska North Slope (via Valdez) as well as from Africa and Indonesia (about 35% of the oil it processes comes from foreign imports). The refinery produces jet fuel, diesel, heating oil, gasoline, liquefied petroleum gas (LPG), heavy oils, bunker fuels and liquid asphalt. Tesoro supplies the Anchorage airport, the Pacific Northwest, and local fueling stations. Tesoro has over 100 Tesoro branded retail outlets. Tesoro's Kenai facility is currently the only refinery in Alaska capable of meeting the EPA's 2006 ultra low sulfur diesel regulatory requirements.

Through phone conversations and e-mail correspondence, all Alaska refineries have expressed serious interest in the F-T product for which they would pay a premium price. The refiners are impressed not only with the product specifications, but also the project, and have requested to be kept abreast with any new developments.

3.5 Military Market Segment

The military market for diesel and jet fuel is a sizable and stable market potential for cleaner fuels from the F-T process. JP-5 and JP-8 jet fuels are the military's most consumed distillate fuels. There are five major military installations in Alaska that are the predominant military users of distillate. These are:

- Eielson Air Force Base
- Elmendorf Air Force Base
- Fort Wainwright Army Base
- Fort Richardson Army Base
- Kodiak Integrated Support Command (the largest U.S. Coast Guard installation)

The Energy Information Agency (EIA) reported the U.S. Department of Defense (DoD) used 275,000 barrels of distillate fuels in Alaska in 2004 (Table 3-5). The DoD does not release detailed fuel consumption data for security reasons. Therefore, the 275,000 bbl/yr figure is likely an estimated value. In comparison, the U.S. Air Force (USAF) consumed 76,000,000 barrels of aviation fuel in FY 2005 (Hoffman, 2006).

Table 3-5 Alaska Military Distillate Fuel Consumption 2004 (bbl/yr)

Diesel	247,000
Other Distillate	28,000
TOTAL	**275,000**

EIA Alaska, Fuel Oil and Kerosene Sale by End Uses, 2004

In addition, smaller, non-operational quantities of fuel are tested in Alaska for performance under low temperature conditions at the U.S. Army's two extreme weather test facilities; the Cold Regions Research & Engineering Laboratory and the Cold Regions Test Center.

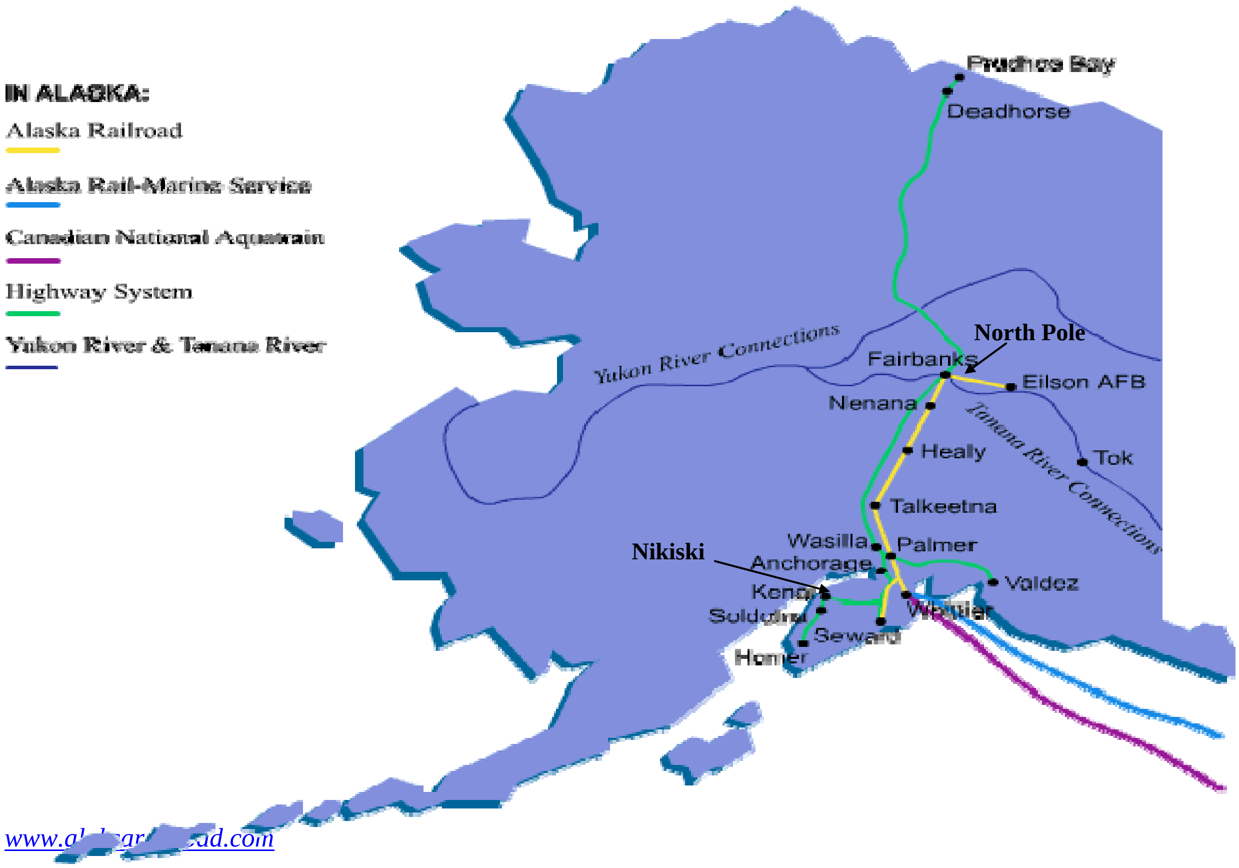
3.6 Product Shipping Markets

The purpose of this section is to estimate the most likely scenarios for moving F-T liquids to market in Alaska. Local refineries in Alaska are the nearest, most likely potential customers for the F-T products. The railroad and barge transportation systems serving Alaska are shown in Figure 3-1.

3.6.1 F-T Liquids

Rail transport is the mode of transport from Healy either to the north or south. For this analysis, it was assumed that the company that builds and finances the Healy Coal-to-Liquids Plant will lease rail cars to move the product on the Alaska Railroad system in the same fashion that the oil refineries currently employ in their business. The Tesoro refinery in Nikiski and the Petro Star refinery in Valdez are not on the Alaska Railroad system. Therefore, barges will be necessary to complete the transportation link from one of the railroad terminus' in Anchorage, Whittier or Seward to the refineries in Nikiski and Valdez. (The Tesoro refinery employs a pipeline to move its refined product to the Anchorage market. It may be feasible to build a parallel pipeline to move F-T liquids to that refinery or to batch F-T liquids in the existing pipeline. However, such an analysis is outside the scope of this investigation.)

Figure 3-1 Alaska Railroad Route and Connecting Carriers



Several scenarios are possible for shipping F-T liquids to various sites in Alaska. Two cases can be readily postulated: (a) all of the product is shipped to North Pole (North Pole is just south of Fairbanks, AK) and is purchased solely by Flint Hills or some combination of Flint Hills and Petro Star, (b) all of the product is purchased by Tesoro and is shipped to Nikiski.

Components of the estimated shipping cost to these locations are shown in Table 3.6.

Table 3-6 Components of shipping costs

Cost Components	To North Pole (100% of Product)	To Nikiski via Anchorage (100% of Product)
Delivered Volume (gal/day)	588,000	588,000
Number of rail cars[18]	137	193
Rail Car Cycle Time (days)	5	7
Rail car daily rate[19] ($/day)	36.07	36.07
Total Rail Car Cost ($/gal)	0.009	0.012
Rail Freight Rate[20] ($/gal)	0.034	0.058
TOTAL Rail Cost ($/gal)	0.043	0.070
Load/Unload Cost[21] ($/gal) Barge Rate	0.02 n/a	0.01 0.04
Dock Handling ($/gal–3 transfers) Shipping Cost ($/gal)	n/a 0.063	0.02 0.14
Shipping Cost ($/bbl)	2.65	5.88

Factors in tabulating shipping costs include:

- *Delivered volume*–dictates the number of rail cars required.
- *Number of rail cars*–based on the number of cars required to deliver the daily volume and the cycle time. A contingency of about 10% is added for maintenance.
- *Rail car cycle time*–number of days required for the car to make the round trip.
- *Rail car daily rate*–lease rate per car per day on a long term lease including maintenance.
- *Total rail car cost*–the cost of the rail car lease for each gallon delivered.
- *Rail freight rate*–charge by the railroad to move the loaded cars.
- *Total rail cost*–total cost of car leases and railroad charge per gallon delivered.
- *Load/Unload cost*–cost to load/unload the product into or out of the rail car. Each handling is $0.01/gallon. The North Pole route requires one loading at Healy and one unloading cycle at the delivery point. The other routes require one loading at Healy, two handling to get it across the dock (into and out of tankage) onto the barge, and one unloading cycle at the destination.
- *Barge Rate*–estimated cost of barging the product to the refinery in Valdez or Nikiski.
- *Shipping cost*–total cost per gallon or barrel to transport the product to the refinery customer.

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[14] Personal communication, Pat Flynn, Alaska Railroad, June 7, 2006.
[15] Personal communication, Mike Meaney, Trinity Rail Group, LLC, June 8, 2006
[16] Personal communication, Pat Flynn, Alaska Railroad, July 26, 2006
[17] Dock handling, loading/unloading, and barge rate estimates based on private communication, Doug Lechtner, Shoreside Petroleum, July 25, 2006

3.6.2 By-product shipping: slag and sulfur

The by-products of the Healy Coal-to-Liquids Plant include slag and sulfur. For this analysis, it is assumed that these commodities would be shipped in a manner similar to the current procedure for coal–by rail to either Anchorage for use or to a port where it would be loaded onto vessels for export.

Much of the slag might be used in the Anchorage area for construction replacing some of the gravel and aggregate shipped by rail from the Susitna Valley. The cost for shipping coal to Anchorage is estimated at $4.54/ton ($5/tonne).[22] The total cost to deliver aggregate to the Anchorage market is about $7.25/ton–see Table 3.7. Currently, the Municipality of Anchorage purchases aggregate for about $20/ton.[23] (Air cooled slag is sold nationally at approximately $15.50/ton). The price may vary depending on the size of the purchase and details of the negotiated contract. Based on this preliminary information, it is concluded that some portion of the Healy Coal-to-Liquids Plant slag could be sold into the Anchorage market at a profit.

It is assumed that the rail cost for shipping sulfur to the Port of Anchorage will also be $4.54/ton. At the Port, it will be loaded onto vessels for shipment to export markets. The total cost for shipping and handling is summarized in Table 3.7. The price for sulfur ranges from $12 to $85 per ton depending on the destination. The maritime shipping cost will also vary significantly depending upon market conditions, so no attempt has been made to estimate the maritime shipping cost in this study. Therefore, it is sufficient to conclude that the operators of the plant will negotiate contracts for sulfur sales that will be sufficient to offset the cost of shipping and perhaps exceed the break-even cost of moving the product to a market.

Table 3-7 Shipping cost for slag and sulfur

	Slag	**Sulfur**
Destination Market	Anchorage	Export via Sea
Rail ($/ton)	$4.54	$4.54
Off Load ($/ton)*	$2.73	$2.73
Load Vessel ($/ton)	0	$2.73
TOTAL	$7.27	$10.00

* *Estimate based on handling cost of coal at the Seward coal terminal. This may be a high value for slag and sulfur, but is used as a conservative estimate.*

3.7 Electric Power Market

This study relied on an analysis of the railbelt electric grid to assess the amount of power that could be sold to the grid. The analysis in the *Alaska Natural Gas Needs and Market Assessment*[24] showed that the grid could take up to about 80 MWe of power without significant upgrades. The proposed Healy CTL plant would produce 42.5 MWe of power for sale into the grid in addition to its primary product, F-T liquids for a CO_2 sequestration-ready plant (16.5

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[18] This estimate is based on the rail shipping costs reported in the Phase 1 report. There the rail cost from Healy to Seward was reported to be $9/tonne. The rail cost from Healy to Anchorage was estimated to be $5/tonne or $4.54/ton.

[19] McKinnnon, John, Deputy Commissioner of Transportation and Public Facilities, private conversation

[24] Thomas, C. *et al.*, "Alaska Natural Gas Needs and Market Assessment", June 2006.

MWe when CO_2 sequestration is implemented). The price one could expect to receive for the sale of electricity would range from \$0.04 to \$0.06/kWh.

3.8 Summary

In investigating the markets for F-T liquids, it was found that the refining companies in Alaska each expressed interest in purchasing F-T liquids from the proposed plant. For this reason, the market study focused on the quantity refineries might use and how to transport the F-T liquids to them.

Any of the refineries in Alaska are large enough to take the total output of the proposed plant to blend with their existing feedstock, providing low sulfur distillates and fuel oils to eager civilian and military markets. F-T fuels are high quality, which should result in fewer pollutant emissions and better engine performance, but Alaska's climate will dictate the extent to which additive packages are required and the subsequent blending protocol. Infrastructure is in place to accommodate the F-T fuel blend via railway, highway and waterway, for delivery to Alaska's refineries. Reasonable shipping rates are projected between the Healy GTL plant and the various refinery locations in Alaska.

The proposed F-T plant will have two major by-products, slag and sulfur. Slag has the potential to be used as an aggregate substitute for a number of applications, including concrete, cement, and other construction activities.

Sulfur, the number one element worldwide, has a plethora of applications in multiple markets, but not Alaska. Without a profitable market for by-product sulfur in Alaska, and the significant cost to ship overseas, local refineries stockpile substantial quantities of sulfur until it can be sold at a minimal loss. If a proposed Alaska-Canada rail link comes to fruition, the sulfur market is anticipated to expand significantly, considering that Canada is one of the world's largest sulfur consumers.

4. PLANT TECHNOLOGY AND PLANT DESIGN

4.1 Project Background

The objective of this study was to determine the economic feasibility of siting a coal-to-liquids (CTL) plant in the central region of Alaska, specifically near the community of Healy. The Healy CTL plant would use coal from the Usibelli Coal Mine located nearby to co-produce electric power and Fischer-Tropsch liquids (F-T) for local use or for sale in domestic or foreign markets or both.

This is the second study aimed at assessing the feasibility for coal gasification technology for use in Alaska. The first study, *Beluga Coal Gasification Feasibility Study*,[25] focused on determining the feasibility of locating a coal-to-syngas plant at the current Agrium Nitrogen Operations plant site near Kenai, Alaska, for providing feedstock to replace the natural gas currently used. This study expands on the Beluga coal gasification analysis by optimizing the plant design for F-T liquids production and power requirements:

- Assess coal plant technology–Identify the technical coal power generation and chemical/fuels production options that are most favorable for the Healy site, production plant and distribution system. The Phase 1 design will form the basis for this task.
- Determine electric power market impact–need for any new transmission lines and the impact on the regional grid. No significant impact is expected if the plant output is less than 70 MWe.
- Analyze environmental permitting issues–Evaluate major potential risks and challenges to developing the Healy plant and related project features deemed most economical in this study. The same permits identified for the Agrium plant will be used as a beginning point. Changes because of the Healy location will be noted.
- Identify stakeholder and/or Native corporation issues.
- System Economics–The NETL economic model will be applied to the various options to determine the system's economic parameters and financial feasibility.
- Identify any other apparent risks or challenges.

4.1.1 Site Description

The characteristics of the host site are presented in Tables 4.1 and 4.2.

Table 4-1 Site Ambient Conditions

Elevation, ft	1300
Barometric Pressure, psia	14.7
Design Ambient Temperature, Dry Bulb, °F	34
Design Ambient Relative Humidity, %	45

[25] Chaney, R.E. and L.E. Van Bibber, et al, RDS, "Beluga Coal Gasification Feasibility Study", Contract No. DE-AM26-04NT41817, Task 333.01.01, July 2006.

Table 4-2 Site Characteristics

Location	Usibelli Coal mine, Healy, Alaska
Topography	Level
Size, acres	20
Transportation	Rail and Highway Access
Ash Disposal	Return to mine
Water	Wells
Access	Landlocked - Rail and Highway Access

The following design parameters are site-specific and are provided for the host facility:

- Existing soil/site conditions: Soil bearing capacity is a function of depth as follows:
  - 4 ft–3,000 lb/ft^2.
  - 6 ft–3,000 lb/ft^2 for foundations < 5 ft wide and 5,000 lb/ft^2 for foundations > 5 ft wide.
  - 12 ft–5,000 lb/ft^2 for foundations < 5 ft wide and 8,000 lb/ft^2 for foundations > 5 ft wide.
- Major foundations should use spread footings. Soil resistivity should be a reasonable number for sandy soil. The design frost penetration is 12 ft below grade.
- Water discharges and reuse: Maximum recycle, discharge treated.
- Rainfall/snowfall criteria: Design one hour rainfall is 0.6-in/hr (minimum duration of 30-minutes), and the design 24-hour rainfall is 2.5-in. The design snow load is 50 lb/ft^2.
- Seismic design: The structural design basis is for seismic zone 4.
- Buildings/enclosures: Minimum requirements.
- Fire protection: As required.
- Local code height requirements: None.
- Noise regulations: Minimum impact on site and surrounding area.

4.1.2 Design Coal

The design coal for this study is Jumbo Dome deposit from the Usibelli Mine. Mine coal properties are shown in Table 4.3. Design coal properties are similar to that shown with some variations in shown in Table 4.4.

Table 4-3 Jumbo Dome Coal Properties

	Seam #3	**Seam #4**
Seam Thickness, feet	27.5	38
HHV, Btu/lb	7,666	8,034
Moisture	28.0%	28.0%
Ash	9.1%	4.6%
Sulfur	0.14%	0.12%

Table 4-4 Design Coal

Rank	Sub-bituminous	
Source	Usibelli Mine	
Proximate Analysis (weight %)		
	As Received	Dry
Moisture	27.00	0.00
Ash	10.00	13.70
Volatile Matter	33.20	45.48
Fixed Carbon	29.67	40.64
Sulfur	0.13	0.18
Total	100.00	100.00
HHV, Btu/lb	7,650	10,479
Ultimate Analysis (weight %)		
	As Received	Dry
Moisture	27.00	0.00
Ash	10.00	13.7
Carbon	44.32	60.71
Hydrogen	3.24	4.44
Nitrogen	0.84	1.15
Chlorine	0.01	0.01
Sulfur	0.16	0.22
Oxygen	14.43	19.77
Total	100.00	100.00

4.1.3 Environmental Requirements

The environmental requirements are summarized in Table 4.5.

Table 4-5 Beluga Coal IGCC Study Environmental Design Basis

Pollutant	Project Emission Limits
Particulate Matter (PM),	0.01 lb/MMBtu (0.09 lb/MW-hr)
Sulfur Dioxide (SO_2)	0.022 lb/MMBtu (0.19 lb/MW-hr)
Nitrogen Oxides (NOx)	0.059 lb/MMBtu (0.51 lb/MWh, 15 ppmvd corrected to 15 volume % oxygen)
Carbon Monoxide (CO)	0.03 lb/MMBtu (0.026 lb/MW-hr)
Volatile Organic Compounds (VOC)	0.002 lb/MMBtu (0.017 lb/MW-hr)

The following additional regulatory assumptions are used in the design basis for assessing environmental control technologies:

- Solid waste disposal is on-site at no cost.
- Raw water is available at a flow rate of 1,500 gpm for process water and 3,000 gpm for cooling water.
- Wastewater discharge will meet effluent guidelines rather than water quality standards for this analysis.

4.1.4 Balance of Plant

Assumed balance of plant requirements are described in Table 4-6.

Table 4-6 Requirements for Balance of Plant

Cooling system	Recirculating, Evaporative Cooling Tower.
Fuel and Other storage	
Coal	Mine mouth "just-in-time" supply
Slag	30 days
Sulfur	30 days
Plant Distribution Voltage	
Motors below 1 hp	110/220 volt
Motors 250 hp and below	480 volt
Motors above 250 hp	4,160 volt
Motors above 5,000 hp	13,800 volt
Steam and Gas Turbine Generators	24,000 volt
Grid Interconnection Voltage	345 kV
Water and Waste Water	
Makeup Water	Process water is available from impoundments at a flow rate of 1,500 gpm. The quality of the process water is shown in Table 4.7.
Feed Water	Treatment of the process water supply is included and will produce boiler feed quality water for the IGCC plant.
Process Wastewater	Water associated with gasification activity and storm water that contacts equipment surfaces will be collected and treated for discharge through a permitted discharge permit.

Sanitary Waste Disposal	Design will include a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge will be hauled off site.
Water Discharge	Most of the wastewater is to be recycled for plant needs. Blowdown will be treated for chloride and metals, and discharged.
Solid Waste	Gasifier slag is assumed to be a solid waste that is classified as non-hazardous. A waste disposal site at the Usibelli Mine is assumed to have the capacity to accept waste generated throughout the life of the facility. Solid waste sent to disposal is at an assumed nominal fee per ton, even if the waste is hauled back to the mine. Solid waste generated that can be recycled or reused is assumed to be a zero cost to the technology

Water from impoundments at the site will be used as cooling water. The water will also be treated and used as process water. Water composition and physical properties are shown in Table 4.7.

Table 4-7 Typical Process & Cooling Water Properties Plant Design

Property	**Process Water**	**Cooling Water**
Total Dissolved Solids (TDS)	200 $\mu g/cm^3$	1250 $\mu g/cm^3$
Total Suspended Solids (TSS)	Not Available	Not Available
Hardness	100 mg/l as $CaCO_3$	75 mg/l as $CaCO_3$
Alkalinity	100 ppm	350 ppm
Sulfate	4 ppm	50 ppm
Chloride	10 ppm	200 ppm
Silica	30 mg/l	30 mg/l
Aluminum	Not Available	Not Available
Iron	0.25 mg/l	0.25 mg/l
Calcium	70 mg/l	25 mg/l
Magnesium	25 mg/l	45 mg/l
Phosphate	0.4 mg/l	6.0 mg/l (ortho)
Ammonia	<1 mg/l	19 mg/l
Chlorine	<0.1 mg/l	<0.1 mg/l
pH	8.0	8.0

The Phase 1 Agrium gasification plant was optimized for producing hydrogen and CO_2. This Phase 2 Healy CTL plant is based on the same technology but is optimized for F-T liquids production. Following is a summary of the Healy CTL plant configuration:

4.2 Process and performance summary

The following list sets our the distinct steps or processes required to produce F-T liquids and power:

1. E-Gas™ slurry-feed gasifier
2. 95 mol% oxygen produced by cryogenic ASU
3. Syngas cooler and slag removal at gasifier outlet
4. Syngas scrubber for chlorides removal
5. COS+HCN hydrolysis reactors
6. Mercury removal (activated carbon bed)
7. CrystaSulf acid gas removal with sulfur polisher
8. F-T process with off-gas recycle and additional hydrotreating
9. Power production with excess power exported

The Healy Coal-to-Liquids Plant is designed to use indigenous coal to produce F-T liquids for shipment off site by rail car. The amount of coal being fed to the plant from the Usibelli mine in close proximity to the plant site is approximately 4 million tons per year. The resultant liquids produced are more than 14,600 barrels per day. In addition, 42.5 MW power is produced for export to the grid (as shown in Figure 4-1).

The gasification plant is fueled with Alaskan sub-bituminous coal delivered by truck to the plant site. The coal is pulverized and mixed with water to make a slurry. The E-GAS™ two-stage coal gasification technology features an oxygen-blown, entrained flow, refractory lined gasifier with continuous slag removal. The coal/water slurry is injected into the gasifier with a split to the primary and secondary stages. The slurry reacts with oxygen in the primary stage at about 2,500ºF, while the slurry fraction injected into the second stage quenches the reaction with endothermic gasification reactions, resulting in a syngas at ~1,900ºF. The plant uses 11,700 tons per day of coal and requires four gasification trains. A turnkey, multi-train, dedicated air separation unit supplies oxygen of 95% purity to the gasifiers and pure nitrogen as feed for combustion turbine fuel dilution.

High temperature syngas leaving each gasifier is cooled in a fire-tube syngas cooler, producing high-pressure steam. Particulate matter is removed from the cooled gas via a cyclone collector followed by a ceramic candle filter. The raw syngas is further cleaned in a spray scrubber to remove remaining particulate and trace components. At that point, the four gasifiers are manifolded together to provide a common syngas source.

The syngas is reheated and goes through a COS hydrolysis reactor in which the COS and HCN are hydrolyzed to H_2S, followed by additional cooling, where some water and nearly 100% of the ammonia are removed from the syngas.

The syngas then passes through a mercury removal system based on technology similar to what has been used at Eastman Chemical’s gasification plant in Kingsport, Tennessee. Dual beds of sulfur-impregnated carbon with approximately a 20-second superficial gas residence time should achieve >90% reduction of mercury in addition to removal of other volatile heavy metals such as arsenic.

H_2S is preferentially removed from the cool, particulate-free gas stream with CrystaSulf solvent, producing a concentrated H_2S product stream. The H_2S stream recovered is fed to a CrystaSulf plant to produce elemental sulfur.

Clean syngas leaving the CrystaSulf system contains <5 ppm total sulfur. The sulfur level is reduced to <1 ppb using a zinc oxide sulfur polishing bed. This low-sulfur syngas is used as feed for the F-T process to produce low-sulfur diesel fuel.

The F-T process converts the clean syngas to 14,640 barrels per day of hydrocarbon liquids per day, consisting of both naphtha and distillate feed for refineries off-site.

The objective of the process design is to maximize the liquid production, which results in the recycle of the off-gas from the F-T reactor with CO_2 removal. Additional hydrotreating was conducted on the heavier F-T products to stabilize them and to lower their pour point and make them suitable for transport by tanker.

The off-gas from the F-T process is compressed and used as fuel for the gas turbine. The two gas turbines produce 28.9 MWe each. Hot flue gas from the gas turbine passes through a heat recovery steam generator (HRSG) in which additional high-pressure steam is produced; the resulting steam produces 135 MWe from a steam turbine.

Overall performance for the entire plant including auxiliary power requirements is summarized in Table 4.8. The net plant output power, after plant auxiliary power requirements are deducted, is nominally 42.5 MW_e.[26] The overall plant thermal effective efficiency (thermal value of F-T product and power produced) is 44.5%, on an HHV basis. If CO_2 is sequestered, additional compressors will be required that are estimated to require and additional 26 MWe reducing the overall plant thermal efficiency to 43.3%.

Figure 4.1 is a block flow diagram for the plant, and is accompanied by Table 4.9, which includes detailed process stream composition and state points.

[26] Note that due to the potential sale price for power at various levels, the economic analyses assumed 42.5 MW of power available for sale to the grid.

Table 4-8 Healy Coal-to-Liquids Plant–Plant Performance Summary E-Gas Gasifier, H/P ASU, LM2500 G/T

Plant Output		
Gas Turbine Power	57,720	kW_e
Steam Turbine Power	135,207	kW_e
Total	**192,927**	**kW_e**
F-T Liquids Production		
F-T Liquids Production	14,640	bbl/day
Auxiliary Load		
Coal Handling	180	kW_e
Coal Milling	4,550	kW_e
Coal Slurry Pumps	1,090	kW_e
Slag Handling and Dewatering	2,330	kW_e
Air Separation Unit Main Air Compressor	94,500	kW_e
Oxygen Compressor	18,650	kW_e
Fuel Gas Compressor	6,803	kW_e
Syngas Recycle Blower	1,701	kW_e
All F-T Processes	8,010	kW_e
Boiler Feedwater Pumps	2,525	kW_e
Condensate Pump	25	kW_e
Flash Bottoms Pump	386	kW_e
Circulating Water Pump	1,800	kW_e
Cooling Tower Fans	410	kW_e
Scrubber Pumps	400	kW_e
Gas Turbine Auxiliaries	2,000	kW_e
Steam Turbine Auxiliaries	1,000	kW_e
CrystaSulf Plant Auxiliaries	500	kW_e
Miscellaneous Balance-of-Plant	3,000	kW_e
Transformer Losses	560	kW_e
Total Net Auxiliary Load	**150,420**	**kW_e**
Plant Performance–CO_2 Sequestration Ready		
Net Plant Power	42,507	kW_e
Net Plant Thermal Efficiency (HHV)	44.5%	
Coal Feed Flowrate	975,000	lb/hr
Thermal Input[1]	2,185,944	kW_t
Elemental Sulfur Production[2]	18.4	tons/day
Condenser Duty	434	MMBtu/hr
Plant Performance with CO_2 Sequestration		
CO_2 Compressor	26,000	kWe
Net plant power–Alternate Case	16,507	kWe
Net Plant Thermal Efficiency–Alternate Case	43.3%	

1 – HHV of as-fed Usibelli 27% moisture coal is 7,650 Btu/lb.
2 – Predicted based on 99.5% sulfur recovery in CrystaSulf unit.

Figure 4-1 Process Block Flow Diagram
E-Gas™ Gasifier-Based F-T Liquid Production Plant

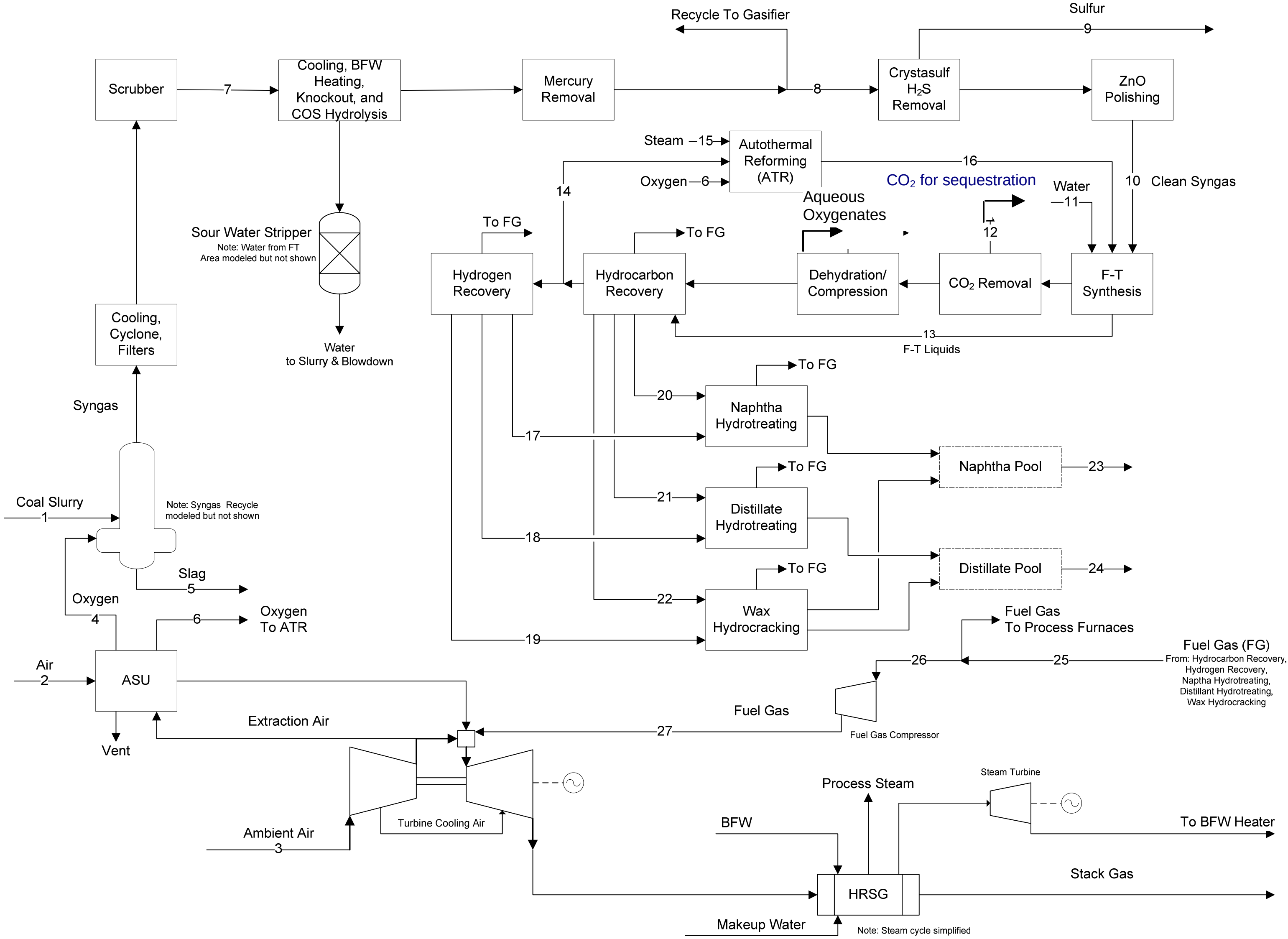


Table 4-9 Process Stream Compositions and State Points

	1^{A}	2	3	4	5	6	7	8	9	10
	Slurry	Air	Air	Oxygen	Slag	Oxygen	Syngas	Syngas	Sulfur	Syngas
V-L Mole Fraction										
Ar	0	0.0094	0.0094	0.0360	0	0.0360	0.0090	0.0117	0	0.0117
CH_4	0	0	0	0	0	0	0.0042	0.0054	0	0.0054
CO	0	0	0	0	0	0	0.2724	0.3521	0	0.3523
CO_2	0	0.0003	0.0003	0	0	0	0.1993	0.2577	0	0.2586
COS	0	0	0	0	0	0	0	0	0	0
H_2	0	0	0	0	0	0	0.2774	0.3586	0	0.3588
H_2O	1.0	0.0104	0.0104	0	0	0	0.2273	0.0027	0	0.0001
H_2S	0	0	0	0	0	0	0.0006	0.0008	0	0
N_2	0	0.7722	0.7722	0.0140	0	0.0140	0.0084	0.0109	0	0.0109
NH_3	0	0	0	0	0	0	0.0013	0	0	0.0021
O_2	0	0.2077	0.2077	0.9500	0	0.9500	0	0	0	0
SO_2	0	0	0	0	0	0	0	0	0	0
Total	1.0	1.0	1.0	1.0	0.0	1.0	1.0	1.0	0	1.0
V-L Flowrate (lb_{mol}/hr)	35,065	81,496	44,096	18,721	0	305	93,176	57,656	0	57,569
V-L Flowrate (lb/hr)	631,175	2,351,530	1,272,348	603,356	0	9,799	2,027,920	1,318,170	0	1,316,600
Solids Flowrate (lb/hr)	711,750	0	0	0	102,319	0	0	0	1,531	0
Temperature (°F)	118	59	59	305	1,850	90	330	103	105	600
Pressure (psia)	550.0	14.4	14.4	560.0	500.0	56.4	434.2	372.8	14.7	347.8
Density (lb/ft^3)	---	0.075	0.075	2.199	---	0.308	1.115	1.428	---	0.696
Molecular Weight	---	28.85	28.85	32.23	---	32.18	21.76	22.86	---	22.870

A - Solids flowrate includes dry coal; V-L flowrate includes slurry water and water from coal

Note: The mass fraction of Argon in stream 10 is added to the mass fraction of Nitrogen before entering the FT- Reactor. This is done because the F-T reactor model cannot handle Argon.

Table 4-9 Process Stream Compositions and State Points (Continued)

	11	12	13	14	15	16	17	18	19	20
V-L Mole Fraction	Water	CO2	F-T Liquids	Recycle	Steam	Recycle	H2	H2	H2	F-T Liquids
H2	0	0	0.0064	0.53094	0	0.49345	1.0	1.0	1.0	0
N2	0	0	0.0062	0.34577	0	0.26178	0	0	0	0
O2	0	0	0	0	0	0	0	0	0	0
H2S	0	0	0	0	0	0.000001	0	0	0	0
CO	0	0	0.001014	0.05891	0	0.08056	0	0	0	0
CO2	0	1.0	0.054110	0.00489	0	0.01423	0	0	0	0
H2O	1.0	0	0.056898	0	1.0	0.14236	0	0	0	0
NH3	0	0	0.000429	0	0	0	0	0	0	0
COS	0	0	0	0	0	0	0	0	0	0
CH4	0	0	0.001295	0.04803	0	0.00762	0	0	0	0
C2H4	0	0	0.000350	0.00844	0	0	0	0	0	0
C2H6	0	0	0.000101	0.00203	0	0	0	0	0	0
C3H6	0	0	0.000524	0.00081	0	0	0	0	0	0
C3H8	0	0	0.000098	0.00011	0	0	0	0	0	0
IC4H8	0	0	0.000031	0	0	0	0	0	0	0
NC4H8	0	0	0.000594	0.00005	0	0	0	0	0	0
IC4H10	0	0	0.000008	0	0	0	0	0	0	0
NC4H10	0	0	0.000160	0.00001	0	0	0	0	0	0
C5H10	0	0	0.000671	0	0	0	0	0	0	0.0005712
NC5H12	0	0	0.000237	0	0	0	0	0	0	0.0425450
IC5H12	0	0	0.000024	0	0	0	0	0	0	0
C6H12	0	0	0.000909	0	0	0	0	0	0	0.1839028
NC6H14	0	0	0.000293	0	0	0	0	0	0	0.0551697
IC6H14	0	0	0.000030	0	0	0	0	0	0	0.0061310
C7H14	0	0	0.001042	0	0	0	0	0	0	0.1422937
C7H16	0	0	0.000476	0	0	0	0	0	0	0.0609822
C8H16	0	0	0.001248	0	0	0	0	0	0	0.1180705
C8H18	0	0	0.000571	0	0	0	0	0	0	0.0506015
C9H18	0	0	0.001524	0	0	0	0	0	0	0.0979556
C9H20	0	0	0.000689	0	0	0	0	0	0	0.0419809
C10H20	0	0	0.001793	0	0	0	0	0	0	0.0812590
C10H22	0	0	0.000839	0	0	0	0	0	0	0.0348250
C11H22	0	0	0.002175	0	0	0	0	0	0	0
C11H24	0	0	0.000971	0	0	0	0	0	0	0
C12H24	0	0	0.002584	0	0	0	0	0	0	0
C12H26	0	0	0.001153	0	0	0	0	0	0	0
C13H26	0	0	0.003033	0	0	0	0	0	0	0
C13H28	0	0	0.001355	0	0	0	0	0	0	0
C14H28	0	0	0.003536	0	0	0	0	0	0	0
C14H30	0	0	0.001644	0	0	0	0	0	0	0
C15H30	0	0	0.004055	0	0	0	0	0	0	0
C15H32	0	0	0.001812	0	0	0	0	0	0	0
C16H32	0	0	0.004615	0	0	0	0	0	0	0
C16H34	0	0	0.001946	0	0	0	0	0	0	0
C17H34	0	0	0.005095	0	0	0	0	0	0	0
C17H36	0	0	0.002275	0	0	0	0	0	0	0
C18H36	0	0	0.005615	0	0	0	0	0	0	0
C18H38	0	0	0.002483	0	0	0	0	0	0	0
C19H38	0	0	0.006130	0	0	0	0	0	0	0
C19H40	0	0	0.002693	0	0	0	0	0	0	0
C20H40	0	0	0.006622	0	0	0	0	0	0	0
C20H42	0	0	0.002960	0	0	0	0	0	0	0
C7-300HC	0	0	0	0	0	0	0	0	0	0
3-350HC	0	0	0	0	0	0	0	0	0	0
350-5HC	0	0	0	0	0	0	0	0	0	0
500+HC	0	0	0	0	0	0	0	0	0	0
C7-300HT	0	0	0	0	0	0	0	0	0	0
3-350HT	0	0	0	0	0	0	0	0	0	0
350-5HT	0	0	0	0	0	0	0	0	0	0
500+HT	0	0	0	0	0	0	0	0	0	0
OXVAP	0	0	0.000144	0	0	0	0	0	0	0
OXHC	0	0	0.001666	0	0	0	0	0	0	0.0837120
OXH2O	0	0	0.000528	0	0	0	0	0	0	0
C21 - C29 Paraffin/Olefin Mix	0	0	0.150219	0	0	0	0	0	0	0
C30+Waxes	0	0	0.646106	0	0	0	0	0	0	0
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lbmol/hr)	310	22,351	160	10,762	2,264	14,274	243	120	632	316
V-L Flowrate (lb/hr)	5,593	983,665	88,446	147,803	40,781	198,383	490	242	1,275	32,991
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	240	100	488	1,706	650	1,780	100	100	100	100
Pressure (psia)	325	265	304	375	615	355	600	600	120	50
Stream Density (lb/ft3)	56.237	2.138	42.527	0.221	1.022	0.204	0.197	0.197	0.040	43.056
Liquid Vol @ 60°F (ft3/hr)	---	---	---	---	---	---	---	---	---	742.215
Molecular Weight	18.02	44.01	553.15	13.73	18.02	13.90	2.02	2.02	2.02	104.30

Table 4-9 Process Stream Compositions and State Points (Continued)

	21	22	23	24	25	26	27
V-L Mole Fraction	F-T Liquids	F-T Liquids	Naphtha	Distillate	FG	FG	FG
H2	0	0	0	0	0.363694	0.363694	0.363694
N2	0	0	0	0	0.397550	0.397550	0.397550
O2	0	0	0	0	0	0	0
H2S	0	0	0	0	0.000001	0.000001	0.000001
CO	0	0	0	0	0.067733	0.067733	0.067733
CO2	0	0	0	0	0.007815	0.007815	0.007815
H2O	0	0	0	0	0.000825	0.000825	0.000825
NH3	0	0	0	0	0.000005	0.000005	0.000005
COS	0	0	0	0	0	0	0
CH4	0	0	0	0	0.058204	0.058204	0.058204
C2H4	0	0	0	0	0.009767	0.009767	0.009767
C2H6	0	0	0	0	0.007078	0.007078	0.007078
C3H6	0	0	0	0	0.026473	0.026473	0.026473
C3H8	0	0	0	0	0.016312	0.016312	0.016312
IC4H8	0	0	0	0	0.001111	0.001111	0.001111
NC4H8	0	0	0	0	0.021103	0.021103	0.021103
IC4H10	0	0	0	0	0.008634	0.008634	0.008634
NC4H10	0	0	0	0	0.013562	0.013562	0.013562
C5H10	0	0	0.114452	0	0.000015	0.000015	0.000015
NC5H12	0	0	0.083489	0	0.000004	0.000004	0.000004
IC5H12	0	0	0.056389	0	0.000001	0.000001	0.000001
C6H12	0	0	0	0	0.000011	0.000011	0.000011
NC6H14	0	0	0.156882	0	0.000003	0.000003	0.000003
IC6H14	0	0	0.081906	0	0	0	0
C7H14	0	0	0	0	0.000009	0.000009	0.000009
C7H16	0	0	0	0	0.000004	0.000004	0.000004
C8H16	0	0	0	0	0.000008	0.000008	0.000008
C8H18	0	0	0	0	0.000003	0.000003	0.000003
C9H18	0	0	0	0	0.000007	0.000007	0.000007
C9H20	0	0	0	0	0.000003	0.000003	0.000003
C10H20	0	0	0	0	0.000006	0.000006	0.000006
C10H22	0	0	0	0	0.000002	0.000002	0.000002
C11H22	0.1224926	0	0	0	0.000005	0.000005	0.000005
C11H24	0.0524969	0	0	0	0.000002	0.000002	0.000002
C12H24	0.1016003	0	0	0	0.000004	0.000004	0.000004
C12H26	0.0435431	0	0	0	0.000002	0.000002	0.000002
C13H26	0.0842678	0	0	0	0.000003	0.000003	0.000003
C13H28	0.0361148	0	0	0	0.000001	0.000001	0.000001
C14H28	0.0698899	0	0	0	0.000003	0.000003	0.000003
C14H30	0.0299529	0	0	0	0.000001	0.000001	0.000001
C15H30	0.0579636	0	0	0	0.000002	0.000002	0.000002
C15H32	0.0248416	0	0	0	0.000001	0.000001	0.000001
C16H32	0.0480716	0	0	0	0.000002	0.000002	0.000002
C16H34	0.0206020	0	0	0	0.000001	0.000001	0.000001
C17H34	0.0398668	0	0	0	0.000001	0.000001	0.000001
C17H36	0.0170859	0	0	0	0.000001	0.000001	0.000001
C18H36	0.0330626	0	0	0	0.000001	0.000001	0.000001
C18H38	0.0141697	0	0	0	0	0	0
C19H38	0.0274189	0	0	0	0.000001	0.000001	0.000001
C19H40	0.0117511	0	0	0	0	0	0
C20H40	0	0.0259008	0	0	0.000001	0.000001	0.000001
C20H42	0	0.0111005	0	0	0	0	0
C7-300HC	0	0	0.173486	0	0	0	0
3-350HC	0	0	0.045714	0	0	0	0
350-5HC	0	0	0	0.264060	0	0	0
500+HC	0	0	0	0.385942	0	0	0
C7-300HT	0	0	0.233315	0	0	0	0
3-350HT	0	0	0.054367	0	0	0	0
350-5HT	0	0	0	0.240734	0	0	0
500+HT	0	0	0	0.109264	0	0	0
OXVAP	0	0	0	0	0.000002	0.000002	0.000002
OXHC	0.1648080	0	0	0	0.000011	0.000011	0.000011
OXH2O	0	0	0	0	0.000008	0.000008	0.000008
C21 - C29 Paraffin/Olefin Mix	0	0.2726536	0	0	0.000003	0.000003	0.000003
C30+Waxes	0	0.690345	0	0	0	0	0
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lbmol/hr)	174	153	610	408	4,036	3,204	3,204
V-L Flowrate (lb/hr)	30,717	94,408	65,005	92,312	80,448	63,865	63,865
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0
Temperature (°F)	100	100	128	236	89	89	385
Pressure (psia)	50	50	40	20	20	20	460
Stream Density (lb/ft3)	46.129	51.397	40.769	43.600	0.068	0.068	1.003
Liquid Vol @ 60°F (ft3/hr)	635.538	1,811.650	1,519.10	1,905.76	---	---	---
Molecular Weight	176.49	617.85	106.52	226.04	19.93	19.93	19.93

4.2.1 Component Description

The sections below describe individual process components in more detail**.**

Coal Handling System

The coal handling system unloads, prepares, and stores the coal delivered to the plant. As a mine-mouth plant, the normal 30-day coal pile is not required. The scope of the system encompasses the coal-receiving hoppers up to and including the slide gate valves on the outlet of the coal storage silos.

Sub-bituminous coal is delivered to the plant site by either truck or conveyor from the Usibelli mine into two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 6 in. x 0 (15 cm x 0) coal from the feeder is discharged onto a belt conveyor, which transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 3in. x 0 (7.6 cm x 0) by the first of two crushers. The coal then enters the second crusher, which reduces the coal size to 1¼ in x 0 (2.5 cm x 0). A conveyor then delivers the coal to the transfer tower, where the coal is routed to the tripper for distribution to one of the six silos. Two sampling systems are supplied–an as-received sampling system and an as-fired sampling system. Data from these samples are used to support the reliable and efficient operation of the plant.

Coal Grinding and Slurry Preparation

From the coal silos, coal is fed onto a conveyor by vibratory feeders. The conveyor feeds the coal to an inclined conveyor that delivers the coal to the rod mill feed hopper. The feed hopper provides a surge capacity of about two hours and contains two hopper outlets. A vibrating feeder on each hopper outlet supplies the weigh feeder, which in turn feeds a rod mill. Two rod mills each process 60% of the coal feed requirements for each gasifier. The rod mill grinds the coal and wets it with treated slurry water transferred from the slurry water tank by the slurry water pumps. The coal slurry is then discharged into the rod mill product tank. The slurry is then pumped from the rod mill product tank to the slurry storage and slurry blending tanks. All of the tanks are equipped with vertical agitators to keep the coal slurry solids suspended.

The coal grinding system is equipped with a dust suppression system consisting of water sprays aided by a wetting agent. The degree of dust suppression required will depend on local environmental regulations.

The equipment in the coal grinding and slurry preparation system is fabricated of materials appropriate for the abrasive characteristics of the coal. The tanks and agitators are rubber lined. The pumps are either rubber lined or manufactured from hardened metal to minimize erosion. Piping is fabricated of high-density polyethylene (HDPE).

Gasification

The E-GAS™ two-stage coal gasification technology features an oxygen-blown, entrained flow, refractory lined gasifier with continuous slag removal. A 53% dry coal/water slurry is injected into the gasifier at a 78:22 split ratio to the primary and secondary stages. The slurry reacts with oxygen in the primary stage at about 2,500ºF and 500 psia. The coal undergoes partial combustion, releasing heat that causes the gasification reactions to proceed very rapidly and the ash to fuse and flow. A turnkey, dedicated air separation unit supplies oxygen at 95% purity.

The primary gasification zone operates above the ash fusion temperature, thereby ensuring the flow and removal of molten slag. This temperature is maintained by a controlled oxygen feed.

All of the oxygen is used in the first stage in exothermic partial oxidation/gasification reactions. The molten ash exits through a tap hole at the bottom of the primary stage into a water quench, forming an inert vitreous slag. The molten slag is quenched in water and removed in a novel continuous-pressure letdown/dewatering system. Gaseous products from the primary zone flow upward into the second gasification zone, a vertical refractory-lined vessel.

The remaining 22% of preheated slurry is injected in the secondary zone of the gasifier to achieve a full slurry quench. A fraction of the raw fuel gas stream is recycled to promote quenching.

The second gasification stage provides both heating value enhancement and raw syngas cooling. Hot gaseous products from the primary zone provide the thermal energy required to heat and gasify the atomized slurry. These gasification reactions are endothermic and considerably reduce the sensible heat content of the primary zone gases, resulting in quench of the gasification reactions. As a result, the exit temperature of the secondary zone, around 1,900ºF, is much lower than that of the primary zone.

Char produced in the secondary gasification zone leaves the gasifier entrained in the fuel gas stream. The combined downstream cyclone and candle filter particulate control devices remove the char from the fuel gas stream for return to the gasifier first stage.

Raw Gas Cooling

Hot raw gas from the secondary gasification zone exits the gasifier at 1,900ºF. This gas stream is cooled to approximately 1,000ºF in a fire-tube boiler. Waste heat from this cooling is used to generate approximately 548,000 lb/hr of saturated steam at 1,800 psia. This steam represents part of the general heat recovery system that provides high-pressure steam to the facility. The raw syngas is further cooled to 670ºF via heat exchange with the fuel gas saturation water.

Particulate Removal

A cyclone and a ceramic candle filter in series are used to remove any particulate material exiting the secondary gasification zone. This material, char and fly ash, is recycled back to the gasifier. The filter is comprised of an array of ceramic candle elements in a pressure vessel. Filter cleaning is achieved by periodically back pulsing it with fuel gas to remove the fines material. Raw gas exits the candle filter at 665ºF and 455 psia. Below 1,000°F, a large portion of the alkali and volatile metals will condense on particulates and will be captured by the filter element itself.

Gas Scrubbing

The “sour” gas leaving the particulate filter system consists mostly of hydrogen, CO_2, CO, water vapor, nitrogen, and smaller quantities of methane, carbonyl sulfide (COS), H_2S, and NH_3.

The cooled syngas at 375°F enters the scrubber for particulate removal. The quench scrubber washes the syngas in a counter-current flow in two packed beds. The scrubber removes traces of entrained particles, principally unconverted carbon, slag, and metals: the scrubber also removes soluble trace contaminants such as NH_3, HCN, and halide compounds. The bottoms from the scrubber are sent to the slag removal and handling system for processing. Sour water from the scrubber is stripped of sour gas and treated for recycle or discharge.

COS Hydrolysis

After leaving the scrubber, the gas has a residual soot content of less than 1 mg/m^3, and is reheated to a temperature of about 450ºF, suitable for feeding to the COS hydrolysis reactor. The reactor consists of a fixed bed of hydrolysis catalyst which promotes the conversion of COS to and HCN to H_2S, which is the suitable form of sulfur to be captured by the CrystaSulf process downstream.

Sour Gas Stripper

The sour gas stripper removes NH_3, H_2S, and other impurities from the scrubber waste stream. The sour gas stripper consists of a sour drum that accumulates sour water from the gas scrubber and condensate from syngas coolers. Sour water from the drum flows to the sour stripper, which consists of a packed column with a steam-heated reboiler. Sour gas is stripped from the liquid and sent to a central incinerator. Remaining water is sent to wastewater treatment.

Mercury Removal

Mercury removal at the plant is based on packed beds of sulfur-impregnated carbon similar to what has been used at Eastman Chemical's gasification plant. Dual beds of sulfur-impregnated carbon with approximately a 20-second superficial gas residence time should achieve 95% mercury reduction and also removes other volatile heavy metals such as arsenic.

CrystaSulf Acid Gas Removal

CrystaSulf is the acid gas removal (AGR) option considered in this study. [27] CrystaSulf is a non-aqueous sulfur recovery process that removes hydrogen sulfide and SO_2 from gas streams and coverts it into sulfur. The CrystaSulf process utilizes a proprietary non-aqueous solution and operating conditions that promote liquid-phase conversion of H_2S and SO_2 to elemental sulfur. The CrystaSulf is a hydrophobic solution that dissolves elemental sulfur.

The low-sulfur coal and the transport gasifier reactions produce a syngas containing less than 5 ppmv COS and about 1,000 ppmv H_2S. H_2S is removed from the sour syngas in a tray countercurrent tray absorber, where H_2S reacts with dissolved SO_2 in the circulating CrystaSulf scrubbing solution according to the Claus liquid process reaction to produce dissolved elemental sulfur. The CrystaSulf solution has a high solubility for sulfur, which remains totally dissolved at the process operating temperature. The sweet syngas from the absorber, containing 5 to 18 ppm total sulfur depending on COS in the raw gas, exits the system.

A limited amount of H_2S is converted into sulfate and thiosulfate during the process; these species are removed by a proprietary Radian byproduct removal process.

Rich solution from the absorber passes to a flash tank, where the CrystaSulf solution is flashed to near atmospheric pressure, producing a flash gas stream that is recycled upstream from the absorber.

The solution stream from the flash tank is fed to a crystallizer, where the CrystaSulf solution is cooled sufficiently below the absorber temperature to effect crystallization. The higher operating

[27] Curtis O. Rueter, Kenneth E. DeBerry, Kenneth E. McIntosh, and Dennis A. Dalrymple, (CrystaTech, Inc.), CrystaSulf Process for Recovering Sulfur from Gas Streams, presented at the North Texas Gas Processors Association Chapter meeting, April 4, 2000.

temperature elsewhere in the system prevents sulfur crystallization and assures plug-free operation.

The slurry of crystalline sulfur from the crystallizer is fed to a filter or centrifuge that produces a filter cake of elemental sulfur. A low-boiling wash solvent is used to wash the filter cake and remove the residual CrystaSulf solution from the sulfur. The CrystaSulf solution/wash solvent stream from the filter is fed to a solvent recovery unit for separation, where it is rinsed with water. The recovered CrystaSulf solution, the wash solvent and the water are recycled to their respective processes.

Since the inlet sour syngas does not contain SO_2, the SO_2 is carried into the absorber with the lean CrystaSulf solution. The SO_2 is produced by burning a portion of the elemental sulfur product. The SO_2-laden gas from the sulfur burner system is added to the CrystaSulf solution through a scrubber column on the sulfur burner exhaust. In case of possible loss of the SO_2 source, the system has sufficient buffering ability to achieve desired sulfur removal for several hours.

The regenerated CrystaSulf solution is re-heated by exchanging heat with the crystallizer cooling system and returned to the top of the absorber.

Since the F-T catalyst is not sulfur-tolerant, the syngas stream passes through a zinc oxide polishing bed following the CrystaSulf process to drop the sulfur content down to essentially zero.

F-T Process

The F-T process converts the clean syngas to 14,640 barrels per day of hydrocarbon liquids, consisting of both naphtha and distillate feed for off-site refineries.

The F-T slurry-bed reactor converts the sulfur-free syngas primarily into olefinic hydrocarbons by the reaction:

$$n\,CO + 2n\,H_2 = CnH_2n + n\,H_2O$$

The iron-based F-T catalyst also promotes the water-gas shift reaction that produces hydrogen for the F-T synthesis reaction.

$$CO + H_2O = CO_2 + H_2$$

To maximize liquid production, off-gas is recycled from the F-T reactor with CO_2 removal. Additional hydrotreating is conducted to stabilize the heavier F-T products, lower their pour point, and make them suitable for transport by tanker.

The lighter hydrocarbon products that leave the slurry-bed reactor in the vapor phase are cooled, and the condensed liquid is collected. The heavier hydrocarbons are removed as liquids from the reactor, separated from the suspended catalyst, cooled, and combined with the lighter products to make the liquid fuel precursor product.

To maintain constant catalyst activity, fresh catalyst is continually added and spent catalyst is continually withdrawn from the slurry-bed. The fresh catalyst is activated in a reducing atmosphere at an elevated temperature. The catalyst pre-treating system consists of a vessel similar to the slurry-bed reactor, but without the internal cooling facilities.

Clean syngas from the gasification block is preheated and mixed with steam generated in the slurry-bed F-T reactor. The syngas is then fed to the slurry-bed F-T hydrocarbon synthesis reactor, which converts the hydrogen and carbon monoxide into straight-chain olefinic and aliphatic hydrocarbons, carbon dioxide and water. The heat of reaction is removed from the slurry-bed F-T reactor by the generation of 375 psia steam inside tubes located within the slurry-bed reactor. Boiler feed water (BFW) is circulated between the steam drum and the F-T reactor to ensure that BFW is always flowing through the cooling tubes. A cyclone removes entrained catalyst particles from the vapor stream leaving the top of the F-T reactor. The vapor stream is then cooled to 40°F in four heat exchangers.

CO_2 from the vapor stream is captured by the absorption tower of a proprietary amine acid gas removal process. The CO_2 is regenerated from the amine-based solvent and vented or sequestered. The vapor stream is then dehydrated and compressed for recycle to the F-T reactor. If the CO_2 is sequestered, then additional processing steps would be required such as compression and piping the CO_2 off-site.

The liquid hydrocarbon stream leaving the F-T vapor condenser is mixed with the cooled liquid hydrocarbons from the slurry-bed F-T reactor and sent for upgrading into liquid transportation fuels. The liquid stream leaving the slurry-bed F-T reactor passes through a hydroclone to remove a majority of the entrained catalyst particles. The catalyst-rich hydroclone bottoms go to a mixing tank for recycling to the slurry-bed reactor. A portion of the hydroclone bottoms is withdrawn and sent to the catalyst withdrawal system. Residual catalyst particles are removed from the hydroclone overhead stream in the filter system.

The catalyst-free liquid leaving the filter system is flashed to reduce its pressure, and the vapor stream is further cooled to 100°F and flashed. The light hydrocarbons (C5 or less) in the vapor stream are separated for use as gas turbine fuel. The remaining vapor is mixed with the CO_2-free vapor stream for recycle to the F-T reactor. The gas being recycled to the F-T reactor passes through an autothermal reformer, in which the hydrocarbons are converted to syngas, predominantly hydrogen.

The central hydrocarbons process serves several functions. It is a collection point for the liquid and vapor streams and a separation area from which several streams leave. The resultant vapor stream is split, with most of the gas being recycled to the autothermal reformer and the F-T reactor. The rest of the gas goes through a hydrogen recovery process to produce hydrogen that is used for hydrotreating the liquids. The liquids are split into three streams: a naphtha stream, a distillate stream, and the heavy wax stream. Hydrogen is used to hydrotreat the naphtha and distillate streams, and to hydrocrack the wax into naphtha and distillate.

The final liquid product consists of 44% naphtha and 56% distillate. Off-gas from the liquid production processes is used as fuel for the combustion turbines.

Combustion Turbine Generators

The combined fuel gas streams from the F-T process are compressed and sent to two General Electric LM-2500 combustion turbines, each producing 28,900 kW at 60 Hz. The exhaust gas from the combustion turbines passes through a heat recovery steam generator (HRSG) unit. Since the turbine output is discrete, any remaining fuel gas is combusted in a duct burner.

Steam Generation

Steam is generated at several locations in the plant. The gasifier contains a fire-tube boiler of shell-and-tube design, with an overall duty rating of 325 million Btu/hour. The boiler cools the syngas from 1,900 to 700°F, producing saturated steam at 1,750 psia and 617°F. This steam is conveyed to the HRSG, where it is superheated.

The HRSG is a horizontal gas flow, drum-type, multiple-pressure, natural circulation unit that is matched to the characteristics of the gas turbine exhaust gas when firing medium-Btu gas. The high-pressure (HP) drum produces steam at main steam pressure (1,750 psia), while the intermediate-pressure (IP) drum produces steam for export to the cold reheat. The HRSG drum pressures are nominally 1614 psia for the HP and IP turbine sections.

Superheater, boiler, and economizer sections are supported by shop-assembled structural steel. Inlet and outlet ductwork routes the gases from the gas turbine outlet to the HRSG inlet and from the HRSG outlet to the stack. A diverter valve is included in the inlet duct to bypass the gas when appropriate. Suitable expansion joints are also included.

Air Separation Plant

The air separation plant is designed to produce a nominal 7,500 tons/day oxygen (O_2) at 95% purity from two trains. The air compressor is powered by an electric motor. Approximately 10,000 tons/day of nitrogen are also recovered.

The air feed to the air separation unit is supplied from a stand-alone air compressor powered by an electric motor. The filtered air is then compressed in the centrifugal compressor, with intercooling between each stage. The air stream is cooled and then fed to an adsorbent-based pre-purifier system.

The air from the pre-purifier is then split into three streams. About 70% of the air is fed directly to the cold box. About 25 to 30% of the air is compressed in an air booster compressor. This boosted air is then cooled in an aftercooler against cooling water before it is fed to the cold box. About 5% of the air is fed to a turbine driven, single stage, centrifugal booster compressor. This stream is cooled in a shell and tube aftercooler against cooling water before it is fed to the cold box.

All three air feeds are cooled in the cold box to cryogenic temperatures against returning product oxygen and nitrogen streams in plate-and-fin heat exchangers. The large air stream is fed directly to the first distillation column to begin the separation process. The second air stream is liquefied against boiling liquid oxygen before it is fed to the distillation columns. The third, small air stream is fed to the cryogenic expander to produce refrigeration to sustain the cryogenic separation process. The work produced from the expansion is used to power the turbine booster compressor.

Inside the cold box, the air is separated into oxygen and nitrogen products. The oxygen product is withdrawn from the distillation columns as a liquid and is pressurized in a cryogenic pump. The pressurized liquid oxygen is then vaporized against the high-pressure air feed before being warmed to ambient temperature. The gaseous oxygen exits the cold box and is split into two streams. Essentially all of the gaseous oxygen is fed to the centrifugal compressor with intercooling between each stage of compression. The compressed oxygen is then fed to the gasification unit. A small oxygen stream is fed to the autothermal reformer in the F-T area.

Nitrogen is produced from the cold box at two pressure levels. Low-pressure nitrogen is split into two streams. A small portion of the nitrogen is used as the regeneration gas for the pre-purifiers and is vented to the atmosphere. The remaining nitrogen is compressed, if needed, for gas turbine diluent nitrogen.

Flare Stack

A self-supporting, refractory-lined, carbon steel flare stack is provided to combust and dispose of product gas during startup, shutdown, and upset conditions. The flare stack is provided with multiple pilot burners, fueled by natural gas or propane, with pilot home monitoring instrumentation.

4.3 Economic Parameters

Capital cost and production cost estimates were developed for the coal-to-liquids plant based on adjusted vendor-furnished and actual cost data. These costs were the basis for an economic analysis. Because the primary purpose of the plant is to produce F-T liquids, the primary metric is product price in $/bbl. The cost of electricity produced will not be calculated.

4.3.1 Capital Costs

The capital costs at the Total Plant Cost (TPC) level include equipment, materials, labor, indirect construction costs, engineering, and contingencies and are shown in Table 4.10. The TPC estimate is often referred to as the "overnight construction" cost, reflecting what it would cost to build a plant overnight if all equipment, materials and labor were available. The capital costs were determined by estimating the cost of every significant piece of equipment, component, and bulk quantity.

Specific assumptions and conditions attached to the analysis include:

- TPC values are expressed in January 2006 year dollars.
- The estimate represents current commercial offerings for the gasification technology.
- The estimates represent a complete power plant facility, including necessary integrations with the mine.
- The boundary limit is defined as the total plant facility within the "fence line," including coal receiving and water supply system.
- The site is near Healy, adjacent to the Usibelli Coal Mine leased area. Costs are based on a relative equipment/material/labor factor versus Gulf Coast USA.
- Costs are grouped according to a process/system oriented code of accounts. All reasonably allocable components of a system or process are included in the specific system account in contrast to a facility, area, or commodity account structure.

The capital cost, specifically referred to as TPC for this plant, were estimated for the categories consisting of bare erected cost, engineering and home office overheads, and fee plus contingencies. The capital costs were determined through the process of estimating the cost of every significant piece of equipment, component, and bulk quantity.

A project contingency of 25% was included for all components in the economic analysis. The F-T Plant and subsequent liquid fuels processing were accounted under the gas clean up account.

A 10% process contingency was added for that account to reflect the lesser design maturity of the F-T liquids equipment. The capital costs were determined through the process of estimating the cost of every significant piece of equipment, component, and bulk quantity.

Table 4-10 Capital Cost before 25% contingency for uncertainty

Client: DEPARTMENT OF ENERGY **Report Date:** 28-Sep-06
Project: Beluga Coal Gasification Study

TOTAL PLANT COST SUMMARY

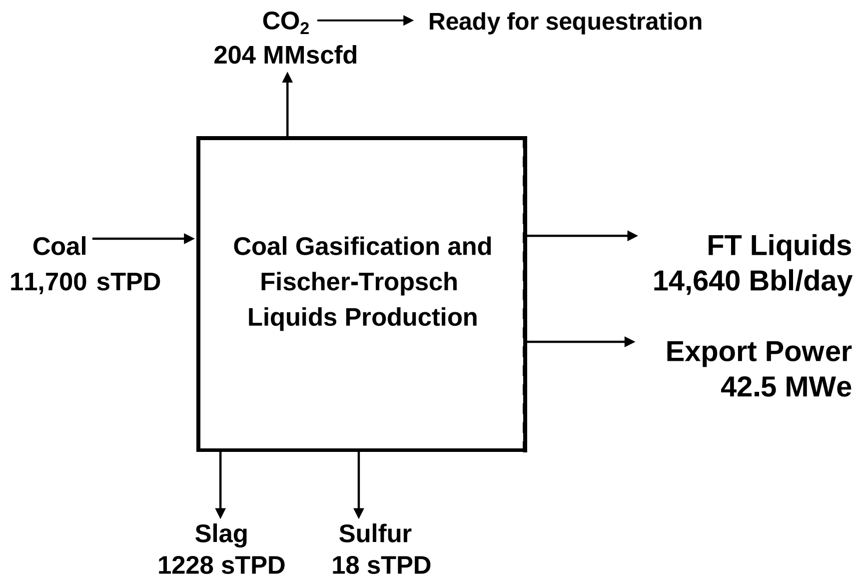
Case: Phase 2 -Healy Coal to Liquid Project-E-Gas, Fischer-Tropsch, Crystasulf, CT, No SO2 Emissions
Plant Size: 42.507 MW,net **Estimate Type:** Conceptual **Cost Base (January)** 2006 ; $x1000
14,640 FT Liquids bbl/day

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOT. PLANT COST $
1	COAL & SORBENT HANDLING	14,542	6,219	40,403	2,828	**63,992**	5,119		17,278	**86,390**
2	COAL-WATER SLURRY PREP & FEED	39,487		65,777	4,604	**118,475**	9,478		31,988	**159,942**
3	FEEDWATER & MISC. BOP SYSTEMS	5,565		6,710	470	**15,299**	1,224		4,131	**20,653**
4	GASIFIER & ACCESSORIES									
4.1	Gasifier & Auxiliaries	98,389		94,811	6,637	**199,837**	15,987		53,956	**269,780**
4.2	Syngas Cooling	31,248		47,506	3,325	**82,080**	6,566		22,162	**110,808**
4.3	ASU/Oxidant Compression	114,220		w/equip.		**114,220**	9,138		30,839	**154,197**
4.4-4.9	Other Gasification Equipment		14,013	25,941	1,816	**41,770**	3,342		11,278	**56,390**
	Subtotal 4	243,857	14,013	168,259	11,778	**437,908**	35,033		118,235	**591,175**
5	GAS CLEANUP	200,930	21,251	103,509	7,246	342,936	26,635	34,848	89,893	**494,312**
6	COMBUSTION TURBINE GENERATOR									
6.1	Combustion Turbine Generator	19,169		626	44	**19,839**	1,587		5,356	**26,782**
6.2-6.9	Combustion Turbine/Generator Accessories		112	99	7	**218**	17		59	**294**
	Subtotal 6	19,169	112	725	51	**20,057**	1,605		5,415	**27,077**
7	HRSG, DUCTING & STACK									
7.1	Heat Recovery Steam Generator	5,520	0	626	44	**6,190**	495		1,671	**8,356**
7.2-7.9	HRSG Accessories, Ductwork and Stack	535	338	399	28	**1,300**	104		351	**1,755**
	Subtotal 7	6,055	338	1,025	72	**7,490**	599		2,022	**10,111**
8	STEAM TURBINE GENERATOR									
8.1	Steam TG & Accessories	13,138		3,538	248	**16,924**	1,354		4,569	**22,847**
8.2-8.9	Turbine Plant Auxiliaries & Steam Piping	5,741	394	4,255	320	**10,710**	857		2,892	**14,459**
	Subtotal 8	18,879	394	7,793	568	**27,634**	2,211		7,461	**37,306**
9	COOLING WATER SYSTEM	3,768	1,975	5,478	383	**11,604**	928		3,133	**15,666**
10	ASH/SPENT SORBENT HANDLING SYS	18,965	3,792	26,063	1,824	**50,644**	4,052		13,674	**68,370**
11	ACCESSORY ELECTRIC PLANT	44,490	13,871	56,402	3,948	**118,711**	9,497		32,052	**160,260**
12	INSTRUMENTATION & CONTROL	22,309		31,427	2,200	**58,391**	4,671		15,766	**78,828**
13	IMPROVEMENTS TO SITE	5,894	3,212	18,209	1,275	**28,589**	2,287		7,719	**38,596**
14	BUILDINGS & STRUCTURES		6,519	14,657	1,026	**22,201**	1,776		5,994	**29,972**
	TOTAL COST	**$643,911**	**$88,051**	**$546,437**	**$38,273**	**$1,323,932**	**$105,115**	**$34,848**	**$354,762**	**$1,818,656**

5. FINANCIAL ANALYSIS

The financial analysis relied on the Nexant-developed Power Systems Financial Model, originally developed in May 2002 and since modified to incorporate additional functionality. The model has been used in numerous gasification studies, and is now the standard used by NETL for IGCC systems analyses. It is a robust discounted cash flow model that takes into account all major financial and scenario assumptions in developing the key economic outputs. The financial analysis examined all segments of the facility, including gasification, power generation, and liquids synthesis. A simplified schematic of the plant inputs and outputs used in the financial modeling can be seen in Figure 5.1 below:

Figure 5-1 Key Plant Inputs/Outputs, Healy Coal-to-Liquids Plant



The key results desired from the analysis were the project return on equity investment, discounted cash flow, and identification of key model sensitivities. In performing the analysis, the value of the F-T liquids was varied to show the financial results from a number of potential scenarios.

5.1 Methodology

Financial analysis incorporates information and data from the following sources: general financial assumptions, capital costs, operation and maintenance costs, and product pricing. The analytical methodology ensured that these data were handled and incorporated in a consistent manner. Appendix B details the financial assumptions used. A few of the major assumptions and some of the areas that were explored by sensitivity analysis are listed below:

- A 25% project contingency applied across the entire plant to reflect the uncertainty in the cost estimate at this phase of the analysis.
- A process contingency of about 10% was assigned to the F-T liquids synthesis unit to reflect greater uncertainty relative to the rest of the plant.
- 85% plant availability.

- 37% tax rate.
- Total operation and maintenance (O&M) costs of 5% of cost of capital per year (fixed and variable).
- 42-month construction period.
- 30-year plant life.
- 70:30 debt-to-equity ratio for project financing, 8% cost of capital.

Specific plant performance and operating data were entered into the model from the design basis. The material and energy balance provided the power output, production rate of F-T liquids, sulfur generation, and coal feed requirements. The plant EPC cost used for the model analysis was determined from installed cost estimates for all major unit operations, off-sites, and balance-of-plant items. A more rigorous explanation of how these numbers were developed is outlined in Section 4.4, Economic Parameters.

The values for most commodity inputs and outputs are based on the analysis included in Sections 2 and 3, along with some information from the *Beluga Coal Gasification Feasibility Study*. The coal price of $15.30/ton is based on information provided by the Usibelli Coal Mine that coal could be delivered to the site for $1.00/MMBtu. Product values for sulfur and electricity in Alaskan markets are based on results from the *Beluga Coal Gasification Feasibility Study*.

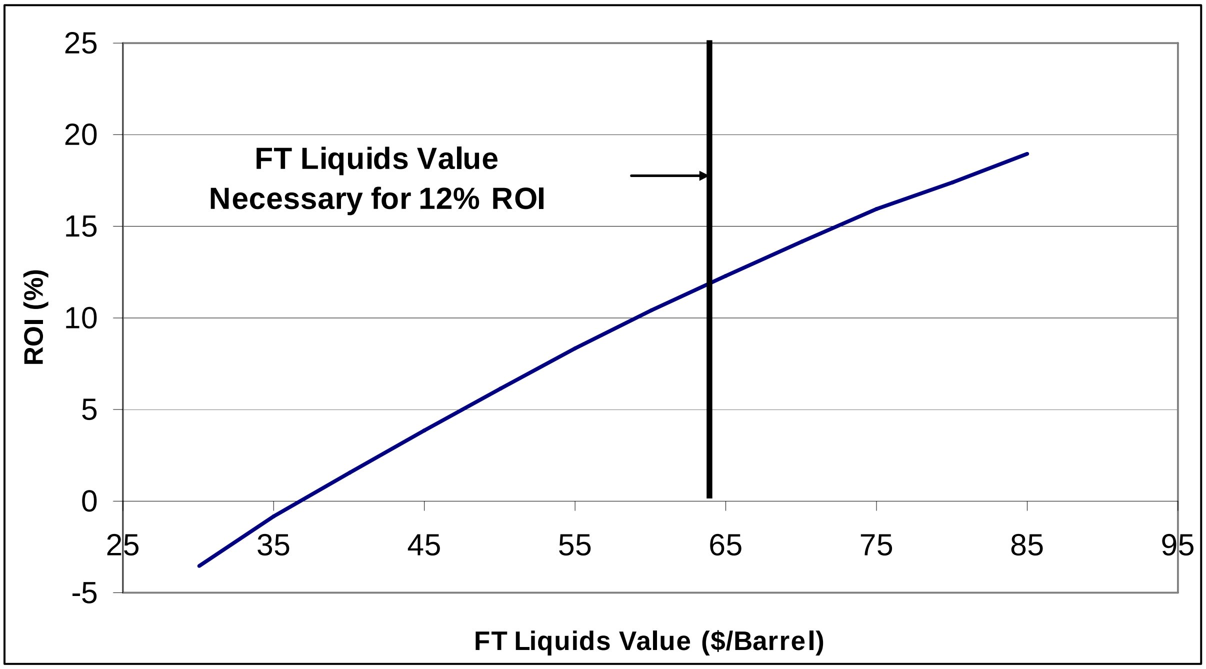
The Power-Systems Financial Model was used to calculate the ROI versus F-T liquid product values over a broad range of potential values. From this curve, the product value to achieve a 12% ROI was determined. This value was then compared with historic crude oil and refined product values in Alaska to determine if the F-T liquids price necessary to obtain a 12% ROI is reasonable. Alternatively, the ROI for the F-T liquids production project was determined for product values equal to the current and anticipated refined oil product values in Alaska.

The financial analysis explored several design variations, including capturing and compressing CO_2 for sequestration in nearby coal seams. Since a unit to separate CO_2 from the F-T product is included in the Base Case design, the enhanced design allowing for sequestration included a compressor for supplying the stream at appropriate pipeline pressure (about 1500 psi), a pipeline for moving CO_2 from the plant to the sequestration site, and injection wells. While some natural gas from coalbeds may be produced as a result of this arrangement, no value was placed on the CO_2. The purpose of this exercise was to determine the impact of CO_2 sequestration on plant costs and financials.

5.2 Model Results

Using a 12% return on equity investment (ROI) as the primary metric in assessing project financial viability, the Power Systems Financial Model evaluated a number of plant configurations and potential product slates. The value of the F-T liquid product has the greatest impact on ROI. Figure 5.2 shows the relationship between ROI and the value of the F-T liquids stream, with all other model inputs held constant. The combined liquids stream must be valued at $64/barrel to meet a 12% return on investment (ROI) for equity participants. Because of its strong impact on ROI, and the high price volatility of liquid fuel products in recent years, developing appropriate price estimates for liquid fuel streams is essential in projecting plant financial performance.

Figure 5-2 Impact of F-T Liquids Value on Plant ROI



To assess the investment potential of an F-T plant, the value of the F-T liquids must be placed in context with the value of other petroleum products in the Alaskan market, such as crude oil, gasoline, and diesel. Predicting a single, firm price for the product is complicated by the volatile nature of the petroleum market and by the number of different potential end uses for the products.

To gauge the investment potential for the Healy Coal-to-Liquids Plant, the value of the F-T liquids must be placed in context with the value of other petroleum products in the Alaskan market, such as crude oil, gasoline and diesel. Two different approaches were considered to estimate the F-T liquid product value:

5.2.1 F-T price relative to ANS crude (most conservative)

As a conservative first estimate, the F-T liquids value necessary to achieve a 12% ROI can be directly compared to recent ANS crude values (in-state Alaska prices). In-state Alaska ANS prices were obtained from published U.S. West Coast ANS crude price adjusted down by the prevailing value of the marine differential for transport to the U.S. West Coast as published by the Alaska Department of Revenue ($1.52/bbl in 2005, $1.67/bbl in 2006, and $1.34/bbl for 2007).[28,29] No premium was added to account for enhanced quality of the F-T liquids. This approach assumes the F-T product could displace ANS crude in the feedslate of local refiners. The average in-state ANS crude price is $57.11 over the 2005 to April 2007 time period.

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[28] ANS Crude Value available at http://www.tax.state.ak.us/programs/oil/prices/ historicaldata//answcprice.asp.
[29] http://www.tax.state.ak.us/programs/oil/prices/prevailingvalue/marine.asp

5.2.2 F-T price relative to refined gasoline and diesel

The raw F-T product contains both diesel and naphtha fractions that would need to be fractionated. The diesel portion of the F-T product can be blended directly with refinery diesel product without further refining and contains no sulfur, low aromatics, and has excellent diesel blending properties. However, the naphtha portion of the product will likely require additional upgrading in a refinery. Refiners would likely pay a premium for the F-T liquids relative to ANS crude. This premium was estimated by using average spot market values for diesel and naphtha in Alaska.[30] The diesel in the F-T barrel was valued at spot diesel prices, while the F-T naphtha was valued at spot gasoline price minus 10 cents per gallon. This discount is applied to account for the low octane value of the F-T naphtha. The actual value of the F-T diesel and naphtha cuts will vary based on the specific importer; other blending properties of the F-T products, such as low sulfur content and high cetane value, may lead to higher values than what is used in this analysis.

The equation used to calculate the value of the F-T product is as follows:

F-T Value ($/gallon) = (0.58 * Spot Diesel Value) + (0.42 * (Spot Gasoline Value – 10 cents)

Under this methodology, the average F-T product price would be about $81.50/bbl or $1.94 per gallon. This is well above the hurdle rate of $66 to $70/bbl necessary to meet the 12% ROI requirement, after adding the $2 to $6/bbl delivery cost to the North Pole refinery or the Nikiski, respectively.

Figure 5-3 shows recent prices for ANS crude oil, diesel and naphtha in Alaska markets. The shaded region shows the F-T liquids value that must be obtained for the project to meet a 12% ROI for equity participants. If the F-T liquids are compared directly to ANS crude (the bottom line in the graph), the project would likely be economic only if nominal crude prices remain high by historic standards. However, pricing the individual F-T fractions so they more closely represent finished product prices (the upper two lines in the graph) would make the project economic over a much wider range of potential market prices.

It is not possible to determine the most likely price for the F-T product at this point. However, it should be bounded by ANS crude price and Alaska refined products prices.

Price information from specific consumers of the F-T products and future projections for crude oil and petroleum product prices are critical to determining if the Healy plant will be economically viable. While refiners in Alaska have expressed interest in the product and have stated that they will pay a premium over crude oil, better estimates should be obtained from Alaskan refiners and potential importers into the lower 48 states to determine how they would value a mixed F-T barrel relative to crude oil, gasoline, or diesel. Once this information is obtained, projections for the future value of petroleum could be made to determine if the price level necessary to make the plant economically viable can be obtained.

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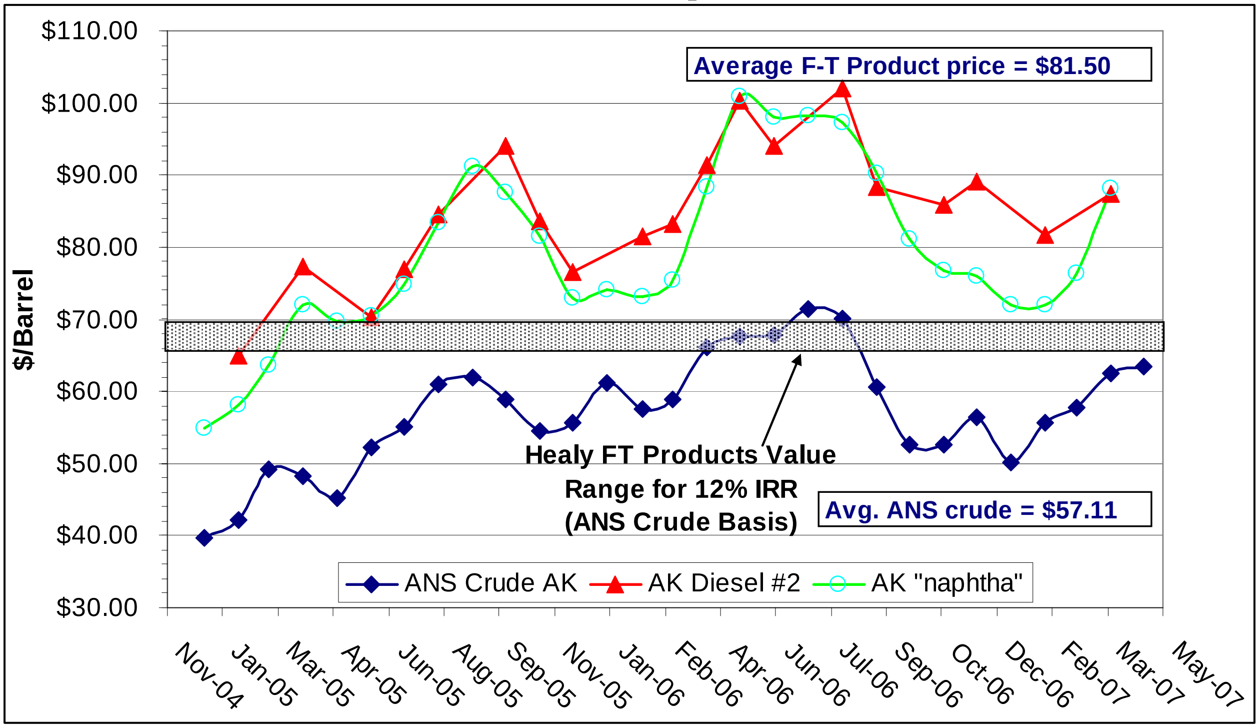
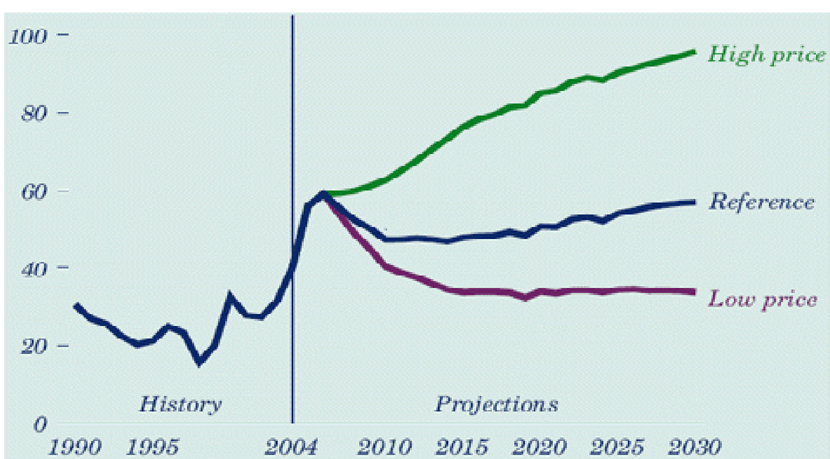
[30] Diesel and Gasoline wholesale spot prices from US DOE Energy Information Administration:
Diesel #2:http://tonto.eia.doe.gov/dnav/pet/hist/a203750022m.htm (missing data points used in Figure 5-3 were not provided by EIA to avoid disclosure of individual company data);
Motor Gasoline: http://tonto.eia.doe.gov/dnav/pet/hist/a103750022m.htm.

Figure 5-3 F-T Liquids Range for 12% ROI versus Spot Crude and Petroleum Product Values, 2005 to April 2007



Historically, crude and refined product prices have been below what would be necessary to achieve a 12% plant ROI. U.S. West Coast ANS crude prices in the 1990s were nominally in the $20/barrel range, while U.S West Coast wholesale gasoline and diesel prices averaged $27 to $30/barrel. This began to change in 2003, when crude topped $40/barrel, and gasoline/diesel cleared $50/barrel. Upward price trends have been seen ever since; the DOE projects prices in 2030 to only fall slightly from 2006 levels, as seen in the EIA Reference Case in Figure 5.4.[31]

Figure 5-4 Crude Oil Price Projections Through 2030



[31] US Department of Energy, Energy Information Administration, Annual Energy Outlook 2006, Figure 85.

If current prices for petroleum products hold at about $60 to 70/barrel, the proposed Healy plant could potentially be economically viable if an appropriate market was established that valued the F-T liquids at a premium to crude oil. The “High Price” scenario outlined in Figure 5.5 would likely lead to ROIs greater than the 12% hurdle rate, while the “Low Price” scenario would lead to an unattractive environment for developing of the Healy plant. Although difficult, assumptions must be made on future prices and markets to determine if an investment of this magnitude should be undertaken.

5.3 Model Sensitivities

Sensitivity analyses were performed with the financial model for a number of economic and operating parameters.

The plant Engineering, Procurement, and Construction (EPC) cost used in the financial model was taken from the analysis done in Section 4.3, with only a few modifications. “Bare Erected Cost” in column 7 of Table 4-10 was combined with the engineering and home office fees shown in Figure 4.10 to produce the EPC cost. On top of these costs, a 25% project contingency, 10% process contingency on the F-T synthesis section of the plant, 2% start-up cost, and 10% owner’s cost were included to reflect the total plant costs.

Table 5.1 below breaks down the total plant cost including EPC costs, fees, start-up costs, and costs incurred from project financing. In addition to the normal project contingency of 25% for a conceptual design, a process contingency of approximately 10% was added to the F-T synthesis section of the plant due to the relative maturity of the F-T process.

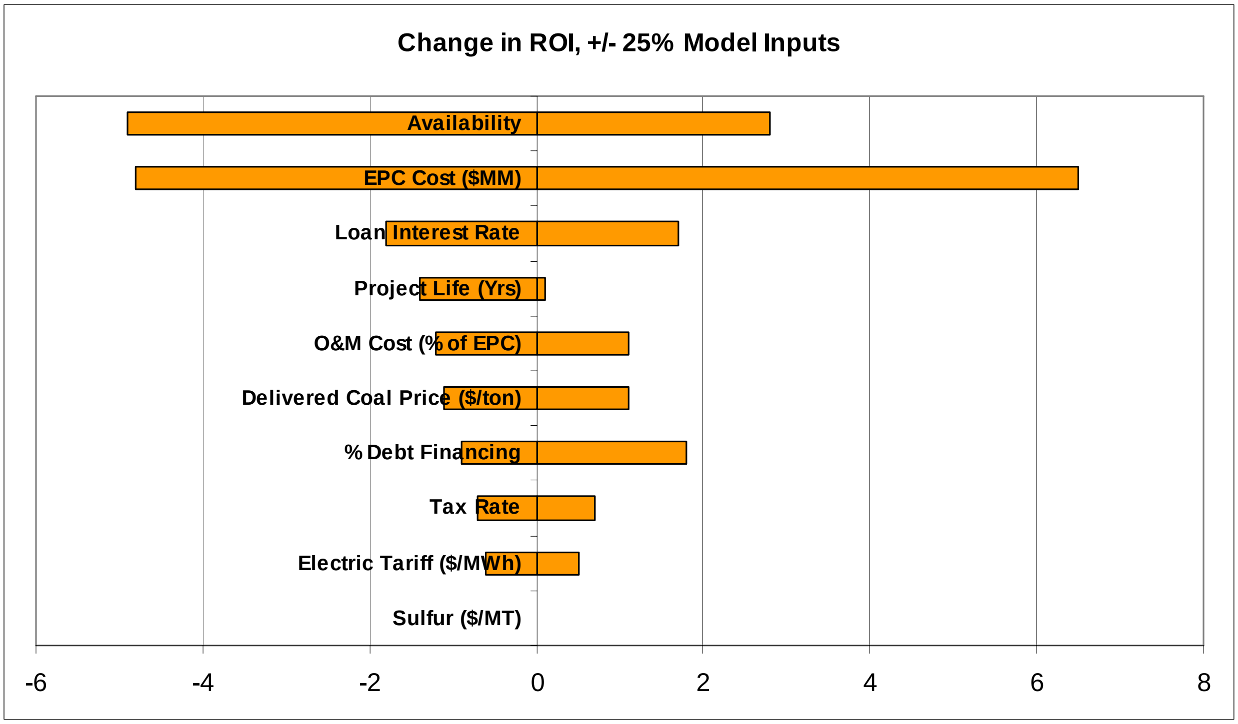
For a coal-to-liquids facility built near Healy, Alaska, with EPC costs of $1.43 billion and a project life of 30 years, an ROI of 12% can be obtained with an F-T liquids value of ~$64/barrel. This value equates to a 10-year payback on the equity investment in the plant.

Table 5-1 Total Plant Costs

Construction/Project Cost (in Thousand Dollars)		
Capital Costs	**Category**	**Percentage**
EPC Costs – BEC plus engineering fees in Table 4.10	$1,429,047	63%
Initial Working Capital	$21,519	1%
Project Contingency	$357,262	16%
Process Contingency (F-T Liquids Synthesis)	$35,094	2%
Start-up (% of EPC Costs)	$28,581	1%
Initial Debt Reserve Fund	$0	0%
Owner's Cost (in thousand dollars)	$142,905	6%
Additional Capital Cost	$0	0%
Total Capital Costs	$2,014,408	89%
Financing Costs		
Interest During Construction	$211,277	9%
Financing Fee	$46,739	2%
Additional Financing Cost	$0	0%
Total Financing Costs	$258,016	11%
Total Project Cost	$2,272,424	100%
Sources of Funds		
Equity	$681,727	30%
Debt	$1,590,697	70%
Total Sources of Funds	$2,272,424	100%

With the exception of plant feed and output rates, all financial model inputs were varied to determine the project financial sensitivities. Model input changes deemed to be reasonable based on previous sensitivity analysis, commodity input ranges, and team estimates were entered into the model. The impact that these changes had on the ROI were examined, using a ±25% change in the unit input as the basis for variable evaluation. The variables and their impact on the financial outputs were then ranked to determine the model inputs of highest sensitivity. Results of this analysis are shown in Figure 5.5 below.

Figure 5-5 Change in ROI, ± 25% Model Inputs

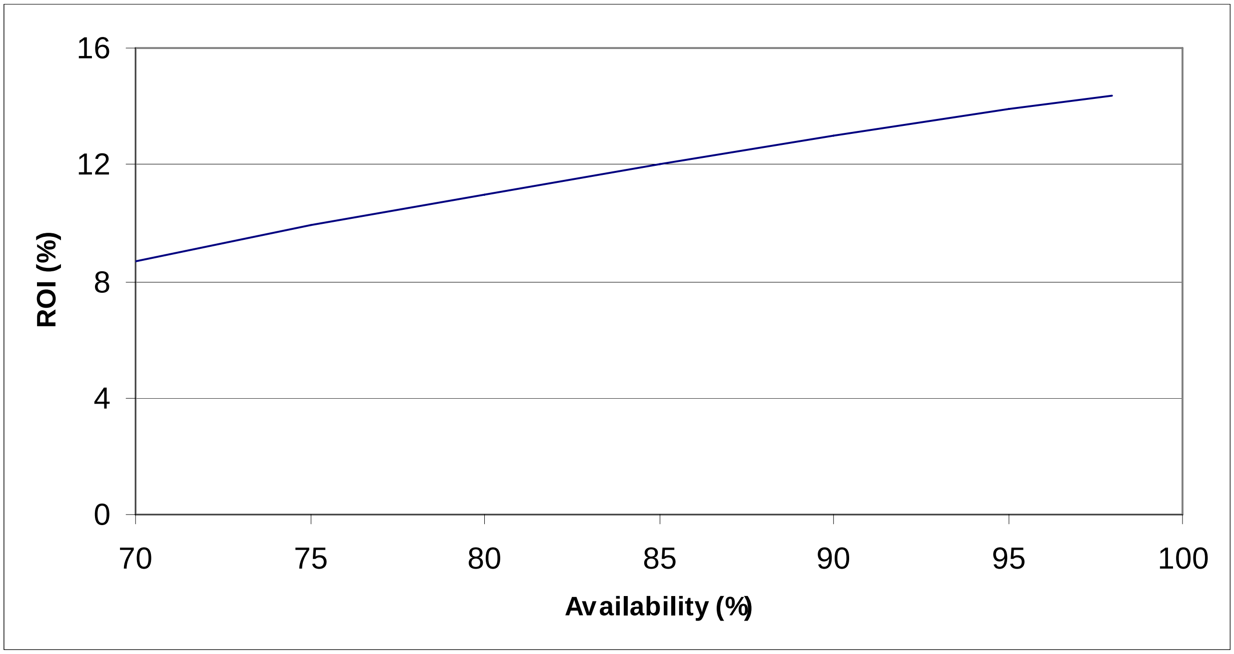


The plant EPC cost has a large impact on the potential plant ROI. Since the financial analysis already includes a 25% project contingency, it is expected that the EPC costs used are on the high end of the range of potential cost estimates. In addition, because other model inputs are based on a percentage of the plant cost (contingency factor and O&M costs, as an example), changes in this variable have a multiplier impact on the overall economic results. In a capital investment of this magnitude, developing the most accurate estimate for the plant cost is critical to understanding the project economics.

The other inputs that had the greatest impact on overall project finances were the plant availability and, as shown in Figure 5.2, the value of the F-T liquids. No other variable impacted the NPV by more than 2 percentage points. Further, while the variable range considered here, ±25%, provides common ground to evaluate all inputs, the possible range of values for some variables could be considerably more.

Figure 5.7 shows the relationship between plant availability and project ROI. Note that availability is not allowed to exceed 100% in either Figure 5.6 or 5.7.

Figure 5-6 Effect of Availability on Project ROI



Reliable operation is very important to assure that the cost of project development and construction can be recovered. Long downtimes throughout the life of the project will significantly hurt overall project economics given a 30-year project life. However, plant availabilities as low as 70% will still provide a plant ROI of over 8%. This shows that concerns over gasification or Healy Coal-to-Liquids Plant performance should not be a major hindrance to project development, since potentially acceptable rates of return can be achieved even with lower than expected availability for this plant.

Based on the analysis where key process variables were changed by 25%, it can be stated that the project financial inputs are robust on a general basis. The rates of return remain positive regardless of the variables changed, provided an acceptable price can be obtained for the F-T liquids. Besides EPC cost, the two items most critical to the financial analysis–availability and F-T liquids value–can vary significantly based on plant design and market conditions. These variables should be carefully examined when considering the range of financial outcomes. Other inputs, while important to a complete picture of a facility's financial potential, do not have the impact of these two factors.

5.4 Effect of CO_2 Sequestration

The basic financial analysis was for a CO_2 sequestration-ready plant design; i.e., the CO_2 is separated and captured ready of sequestration. For geologic sequestration of CO_2, equipment and facilities to compress and transport CO_2 to the sequestration location and injection wells are required. The equipment and facilities added were a CO_2 compressor ($69 million), a pipeline to transport CO_2 ($10 million), and injection wells at the coal bed site ($32 million). The financial model was modified by 1) increasing the EPC cost by $111 million, 2) decreasing the power export by 26 MWe due to the auxiliary load of the CO_2 compressor, and 3) thereby increasing the value of the power export from $46/MWh to $52/MWh (i.e., impact of supply and demand). The results of the supply and demand analysis performed in the *Beluga Coal Gasification*

Feasibility Study provided an estimate of the value of the power as the amount of available to the railbelt grid changed. Assuming no economic value for the CO_2, the ROI of this alternative case drops to 9.7%.

Additional analysis was performed on the sequestration case to estimate the breakeven values needed for F-T liquids and CO_2 to produce financial results equal to the CO_2 sequestration-ready plant design. For F-T liquids, the value would be $70/bbl to achieve a 12% ROI with CO_2 sequestration (i.e., the incremental cost for geological sequestration of the CO_2 is an additional $6/bbl for the F-T product). If CO_2 has a value of $0.42/Mscf (~$7/ton) a 12% ROI is obtained for an F-T value of $64/bbl. This is below the value used for CO_2 in the *Beluga Coal Gasification Feasibility Study* alternative, where CO_2 for enhanced oil recovery was evaluated with a CO_2 value of $0.50/Mscf. Hence, CO_2 sequestration makes the F-T product less competitive with crude oil and refined crude oil products unless it provides an added value such as enhanced oil recovery or enhanced CBNG production. Neither oil production nor CBNG production exists in the area at the present time. (CBNG is untested but potentially viable from the unmineable coal beds in the area.) Without being mandated by law or without development of an economic value for the CO_2 such as enhanced CBNG, implementation of geological sequestration is unlikely to occur.

6. ENVIRONMENTAL PERMITTING AND ISSUES

The objective of this study is to determine the economic feasibility of siting a coal-based gasification plant coupled with an F-T process at the Usibelli Coal Mine. The mine is located approximately 12 miles northwest of Healy, Alaska, and approximately 23 miles northwest of the Denali National Park and Denali Wilderness, a Class I area in Alaska.

The Healy Coal-to-Liquids Plant investigated in this report would require a number of Federal and State environmental construction and operation permits. The relevant permits encompass several major project components:

- Construction and operation of a gasification plant, F-T plant, combustion and steam turbines, and balance-of-plant equipment;
- Tie-in to the electrical grid for delivery of 42.5 MW of power, including of a 3 mile long transmission line connecting the Healy Coal-to-Liquids Plant to the existing GVEA Northern Intertie; and
- Construction of a water supply impoundment along Emma Creek.

As discussed below, the permits also encompass several distinct categories: air emissions, solid and hazardous wastes, water and wastewater, site modifications, and compliance with the National Environmental Policy Act (NEPA).

6.1 Air Emissions

The State of Alaska Department of Environmental Conservation regulates air emissions as established by the Alaska Administrative Code (AAC) in 18 AAC 50, and is the delegated authority for preparing and issuing air quality permits. Nonetheless, the U.S. EPA imposes federal emission limits, monitoring, and reporting from new sources as set out by 40 CFR 60, New Source Performance Standards (NSPS). The State may or may not include these federal requirements into its air quality permits. Regardless of state limits, however, the federal requirements still apply.

The sections below discuss the permitting triggers, permitting requirements, and limits that will be applicable to this project.

6.1.1 Emissions

Table 6-1 presents the project emissions for the gasification plant, based on the emission factors provided in the Design Basis.

Table 6-1 Plant and Project Emissions

Pollutant	Emissions Factors	Project Emissions
Nitrogen Oxides (NOx)	0.059 lb/MMBtu (0.51 lb/MW-hr)	431 tpy
Carbon Monoxide (CO)	0.03 lb/MMBtu (0.026 lb/MW-hr)	22 tpy
Sulfur Dioxide (SO_2)	0.022 lb/MMBtu (0.19 lb/MW-hr)	161 tpy
Particulate Matter (PM-10)	0.01 lb/MMBtu (0.09 lb/MW-hr)	76 tpy
Volatile Organic Compounds (VOC)	0.002 lb/MMBtu (0.017 lb/MW-hr)	14 tpy

The project emissions assume that particulate matter (PM), mercury (Hg), lead (Pb) and hydrogen sulfide (H_2S) control equipment are part of the integral design of the gasification plant. Thus, Hg and Pb emissions from the gasification project are negligible, less than 1 ton per year (tpy). The emissions are considered negligible with respect to hazardous air pollutants (HAPs) because the combined emissions of the entire source (i.e., mine and gasification plant) would be less than the hazardous air pollutants (HAPs) threshold (i.e., less 10 tons per year for a single HAP or 25 tons per year of total HAPs).

Total source emissions, which include the mine and gasification plant, are presented in Table 6-2. The Usibelli Coal Mine's existing emissions were based on Alaska Air Quality Title V Operating Permit No. AQ0317TVP01, issued for the Usibelli Coal Preparation Plant on April 14, 2003. The permit incorporates owner-requested limits to restrict emissions to less than 100 tpy.

Table 6-2 Total Source Emissions for the Healy Coal-to-Liquids Plant and mine

Pollutant	Usibelli Emissions (tpy)	Project Emissions (tpy)	Total Source Emissions (tpy)
Nitrogen Oxides (NOx)	43	431	474
Carbon Monoxide (CO)	46	22	68
Sulfur Dioxide (SO_2)	56	161	217
Particulate Matter (PM-10)	6	76	82
Volatile Organic Compounds (VOC)	5	14	19

6.1.2 Permitting

Air permit requirements for industrial sources such as the Usibelli Coal Mine and the proposed Healy gasification plant depend on a Prevention of Significant Deterioration (PSD) review. For major stationary sources, including fossil fuel-fired steam electric plants of more than 250 million BTU/h heat input based on higher heat value, the threshold that triggers a PSD review is the potential to emit is 100 tpy or more of any regulated pollutant. For minor sources such as the Usibelli Coal Mine, the proposed change must result in an emission increase greater than the major source threshold.

As shown in Table 6-3, the gasification project itself results in annual emission amounts above the major source threshold for two pollutants. Therefore, the project would be subject to PSD review, and the entire stationary source (i.e., gasification plant and mine) would be classified as PSD major. Future physical changes or changes in the method of operation would be scrutinized against the criteria for major modifications (EPA New Source Review Manual, Page A.24).

Table 6-3 PDS Decision Matrix

Pollutant	Project Emissions (tpy)	Major Source Threshold (tpy)	PSD Review?
Nitrogen Oxides (NOx)	431	100	yes
Carbon Monoxide (CO)	22	100	no
Sulfur Dioxide (SO_2)	161	100	yes
Particulate Matter (PM-10)	76	100	no
Volatile Organic Compounds (VOC)	14	100	no

To obtain a PSD permit under 18 AAC 50.306 and the applicable Code of Federal Regulations (CFR) standard, 40 CFR 52.21, an applicant must:

- Apply best available control technology (BACT). A BACT analysis is done on a case-by-case basis, and considers energy, environmental, and economic impacts in determining the maximum degree of reduction achievable for the source. In this project, an analysis would be required to determine the controls (if any) necessary to reduce NOx and SO_2 emissions, the pollutants triggering the PSD review. Specific emissions limits and control technology will be determined by the State.
- Collect pre-construction ambient air data. If predicted ambient impacts are higher than the Significant Monitoring Concentrations, the collection of ambient air data must be collected for a period of four months to one year prior to construction. This data must be submitted with the application and used in the air quality analysis, unless suitable and State-acceptable data was collected near the site by another party. This requirement often stalls projects subject to PSD review.
- Collect meteorological data. If onsite meteorological data cannot be identified, then the collection of site-specific data may be required.
- Conduct an ambient air quality analysis. Each PSD source must perform an air quality analysis to demonstrate that the new pollutant emissions would not violate either the ambient air quality standards or applicable PSD increments. In this project, the air quality modeling analysis would be required for NOx, SO_2, and PM-10 emissions, unless a preliminary analysis resulted in emissions less than the Significant Ambient Impact Levels. These levels are set for Class II and Class I areas. If the project were within 10 km of a Class I area, then the lower Class I levels would be used. Development of limits may be imposed by the State as necessary to comply with the standards and increments.
- Collect post-construction ambient air data. Post-construction monitoring can be required if modeling demonstrates that standards are threatened or there is uncertainty in the modeling inputs.
- Analyze impacts to soils, vegetation, and visibility. Applicants are required to analyze whether proposed emissions increases would impair visibility, or impact upon soils or vegetation. Not only must the applicant look at the direct effect of source emissions on these

resources, it must also consider the impacts from general commercial, residential, and industrial activities, associated with the proposed source. This can often be conducted by research and computer modeling.

- Demonstrate the project does not adversely impact a Class I area. Class I areas are areas of special national or regional natural, scenic, recreational, or historic value for which the PSD regulations provide special protection. EPA policy dictates that all major sources slated for development within 100 km of a Class I area demonstrate no adverse impact on the Class I area. If the Federal Land Manager demonstrates that emissions from a proposed source would impair air quality related values (i.e., flora, fauna, water, visibility, odor, etc.) – even though the emission levels would not cause a violation of the allowable air quality increments – the Federal Land Manager may recommend that the State deny the permit. For this reason, the Federal Land Manager and State should be involved early on in the pre-application phase.
- Demonstrate compliance with applicable emission limits. Each applicant must demonstrate compliance with State emission standards by providing emissions calculations. The State will require further compliance demonstrations through source testing for other State and Federal limits (i.e., BACT limits and NSPS limits).

6.1.3 Applicable Limits

Table 6-4 summarizes the air emission limits applicable to the Healy plant. Applicability is based on a 192.9 MW (gross) plant capacity and emission factors as provided in the Design Basis, with power sales of no more than 42.5 MW (i.e., less than one-third of its potential electric output capacity).

The gasification plant will be subject to 40 CFR 60 Subpart KKKK (as finalized on July 6, 2006) rather than 40 CFR 60 Subpart Da (as final on February 28, 2006) because the stationary source will not be supplying more than one-third of its potential electric output capacity and more than 25 MW net electrical output to any utility power distribution system for sale. Hence, the gasification plant will not be considered an electric utility steam generating unit. Subpart Da has a more stringent NOx limit, less stringent SO_2 limit, as well as limits for PM, mercury, and opacity.

Table 6-4 Applicable Emissions Limits in Alaska

	NOx	CO	SO_2	PM-10	VOC	Hg	Opacity
Emission Factors	0.059 lb/MMBtu (0.51 lb/MW-hr)	0.03 lb/MMBtu (0.026 lb/MW-hr)	0.022 lb/MMBtu (0.19 lb/MW-hr)	0.01 lb/MMBtu (0.09 lb/MW-hr)	0.002 lb/MMBtu (0.017 lb/MW-hr)	To be determined	to be determined
State Emission Limits in 18 AAC 50.055	NA	NA	500 ppm sulfur compounds emissions, expressed as SO_2	0.05 gr/dscf corrected to standard conditions and averaged over 3 hours	NA	NA	20% averaged over any 6 consecutive minutes

	NOx	CO	SO_2	PM-10	VOC	Hg	Opacity
Other State Emission Limits	To Be Developed: BACT Limit and Ambient Air Quality Limit	NA	To Be Developed: BACT Limit and Ambient Air Quality Limit	To Be Developed: BACT Limit and Ambient Air Quality Limit	NA	NA	NA
Federal Emission Limits in 40 CFR 60 Subpart KKKK	160 ng/J (1.3 lb NOx/MW-hr) gross energy output	NA	110 ng/J (0.9 lb/MW-hr) gross energy output	NA	NA	NA	NA

Notes: (1) The NOx limit in 40 CFR 60 Subpart KKKK is for co-generation plant size of greater than 850 MMBtu/hr based on higher heat value. If plant size is less than a heat input capacity of 850 MMBtu/hr, then the NOx limit is increased to 460 ng/J.
(2) Heat recovery steam generators and duct burners regulated under 40 CFR 60 Subpart KKKK are exempted from the requirements of 40 CFR 60 Subparts Da, Db, and Dc.

If the entire source's combined emissions are in excess of the hazardous air pollutants (HAPs) threshold (i.e., over 10 tons per year for a single HAP or 25 tons per year of total HAPs), then the source would be subject to 40 CFR 63 Subpart YYYY and also could be subject to other federal limits for the pollutant in excess.

The gasification plant will also be subject to 40 CFR 60 Subpart Y for Coal Preparation Plants because it processes more than 200 tons per day of coal. This Subpart limits particulate emissions and opacity from thermal dryers, pneumatic coal cleaning equipment, coal processing and conveying equipment, coal storage systems, or coal transfer and loading systems processing coal.

Because the capacity of the Claus sulfur recovery plant is less than 20 long tons per day (i.e., long ton equals 2,240 pounds), it is exempt from 40 CFR 60 Subpart J for Petroleum Refineries.

6.1.4 Air Emissions Conclusion for Building Near a Class I Area

There are several avenues where advanced and early pre-application notice should be implemented to avoid permitting delays or denial of the permit application. More specifically, the regulations can require the collection of ambient air data for a period of 4 months to one year prior to construction. In addition, the Federal Land Manager may recommend that the State deny a permit because they suspect that the project would impair air quality related values in the Class I Area. It would be the obligation of the Permittee to demonstrate otherwise through the use of research, monitoring, and modeling. As such, direct contact with the State and Federal Land Manager should be conducted up to one year in advance to development of an air permit application. Construction cannot occur until issuance of the final permit, which oftentimes can take the State up to one year after submittal.

6.2 Solid and Hazardous Waste

If developed, the project would generate several new solid and hazardous waste streams during construction and operation, and would require handling and storage of non-hazardous and hazardous materials. Existing permits would have to be modified or new permits would have to be obtained from State of Alaska resource agencies, and possibly several federal agencies.

Non-hazardous wastes include the following:

- Construction debris (grubbing, packaging, litter, etc.)
- Coal slag from the gasifier could be marketed as an aggregate or disposed of by landfill
- Fly ash from the gasifier
- Sulfur
- Used catalysts from F-T, hydro-cracking, and hydro-treating processes

Marketing some of these wastes for reuse may be possible (slag and fly ash for use in concrete, sulfur for sulfuric acid, catalyst wastes recycled as micronutrient fertilizer). Disposal in approved landfills and/or in monofills is also an option. Mercury content of slag and fly ash could become a regulatory issue for reuse or disposal in the future.

Hazardous materials to be used at the F-T facility include:

- Anhydrous ammonia
- Chilled methanol
- Sodium hydroxide
- Sulfuric acid
- Caustic soda ash
- Potassium permanganate

Potential hazardous wastes include:

- Spent filter elements and media including spent carbon containing mercury (some are hazardous)
- Spent catalyst wastes for unspecified disposal (hazardous)
- Metals, salts, and sludge from water treatment and cooling tower, as well as amines used to capture CO_2 (potentially hazardous).

All hazardous waste streams will require careful handling and disposal in approved facilities, in full compliance with applicable regulations.

6.3 Water and Wastewater

The proposed project has water supply and wastewater disposal requirements that would require a number of Federal, State and Borough environmental permits:

- Process Water Supply – Process water is available from new wells or surface water impoundments at a flow rate of 1,500 gpm. Well installation and groundwater withdrawal would require permits from the Alaska Department of Natural Resources (ADNR). Creation of a surface water impoundment along Emma Creek as a potential source of water for the project would require several permits from ADNR, including certificates to construct and operate a dam and fill permits from the U.S. Army Corps of Engineers (USACE).

- Wastewater Discharges – Discharge of treated wastewater to surface waters (e.g. Emma Creek) will require a National Pollutant Discharge Elimination System (NPDES) permit. Proposed facilities and operations that could result in surface water discharges to be reviewed under NPDES regulations include domestic wastewater, storm water runoff, coal, and slag storage facility effluent, cooling blow down, industrial process wastewater, and reverse osmosis brine. These effluents typically contain salts, minerals, sulfide, chloride, ammonium and cyanide (Ratafia-Brown 2002). The exact composition of wastewater discharges is unknown at this time. In general, wastewater streams would be treated to remove oil and solids prior to discharge. Advanced treatment for some contaminants may be required. Some waste streams could be disposed of by underground injection, requiring compliance with EPA's Underground Injection Control (UIC) regulations. Total reuse of water is also an option.
- Cooling Water Supply and Discharge – Cooling water requirements of 3,000 gpm could be met by a surface water impoundment or by wells if additional capacity is available. The regulatory requirements would be the same as those for process water supply, as discussed above.

6.4 Site Modifications

The proposed project would be located on a 20-acre site approximately 12 miles northwest of Healy, Alaska, along Emma Creek. The site is currently undeveloped, and would require modifications to accommodate the gasification and F-T facility, power transmission line, and surface water impoundment along Emma Creek. Planning level work that has been conducted for the Emma Creek Power project indicates that vegetation communities in the area include closed spruce forest, floodplain riparian, birch forest, alder/shrub, sub-alpine meadow and alpine tundra. No threatened or endangered plant species are known to exist in the area. Threatened or endangered animal species include arctic peregrine falcon, Aleutian Canada goose, short-tailed albatross, and Eskimo curlew (Usibelli Coal Mine Inc, 2002).

The project site and transmission line corridor should be screened for contaminants (Phase I Environmental Investigation), fish and wildlife habitat characteristics, presence of wetlands and cultural resource sites. The presence of such features could result in additional environmental permit requirements as summarized in Appendix C. If the proposed transmission line would cross state owned lands, a right-of-way authorization from ADNR would also be required.

6.5 National Environmental Policy Act (NEPA) Compliance

The National Environmental Policy Act (42 U.S.C. § 4321 et seq.), NEPA, assures that information on the environmental implications of a federal or federally-funded action is available to public officials and citizens before making decisions or taking actions.

Actions having the potential to significantly impact the environment must be evaluated by federal agencies to determine the environmental consequences, identify reasonable alternatives and document the environmental analysis. One of the involved federal agencies must prepare an

Environmental Assessment (EA) or Environmental Impact Statement (EIS) prior to any of the agencies issuing permits or other approvals for the project as shown in Table 6-5. Federal actions that could trigger the preparation of an EA/EIS include:

- Federal funding or loan guarantees
- Issuance of a NPDES permit to accommodate facility construction and surface water discharges of treated effluent and/or permitting of injection wells under UIC regulations
- Permits to excavate or place fill in wetlands and waters as necessary for project development (USACE)

Table 6-5 NEPA Compliance

NEPA Compliance and Consultation		
Document	**Authority/Regulation**	**Agency**
Draft/Final EIS Preparation	NEPA Compliance	EPA, USACE or DOE
Section 106 Consultation	Section 106 NHPA	EPA, USACE, ADNR
Section 7 Consultation	Section 7 ESA	USFWS

When preparing an EA or EIS, the federal agency must consider not only the gasification and F-T Project (gasifier, turbines, F-T facility, transmission line and surface water impoundment), but Connected Actions and Cumulative Impacts that are related to the project.

- **Connected Actions:** Actions by others that are required for the proposed project to operate, and actions that will result from construction and operation of the proposed project.
- **Cumulative impacts:** Impacts resulting from other past, present, and reasonably foreseeable actions in the project area.

6.6 Applicable Environmental Permits

Table 6.6 below contains a summary of key federal and state and environmental permits that may be required for various aspects of the proposed project. A more comprehensive and descriptive list of applicable Federal, State and local permitting activities is included in Appendix A. The potential applicability of listed regulations is based on the current level of detail regarding design and operation of the proposed gasification and F-T facility, and would be subject to revision based upon further project planning and design.

Table 6-6 Summary of Federal, State and Borough Environmental Permits

Summary of Federal, State and Borough Environmental Permits *Major–Primary Permits/Approvals* *Minor–Administrative Permits/Approvals*			
Medium	**Major**	**Minor**	**Agency**
Air	Construction Permit and Revision to Operating Permit	Open Burning Approval (Construction)	ADEC
Water/Wastewater	NPDES Permit	SPCC Plan	EPA
	Section 401 Certification	Solid Waste Plan	ADEC
	Certification of Reasonableness – 402/404	SPCC Plan	ADEC
	Injection Well Permit		EPA
Navigable Waterways/ Waters of the US	CWA Section 404		USACE
	Rivers & Harbors Section 10		USACE
Water Supply	Water Rights Appropriation		ADNR
	Water Supply Permit		ADEC
Ecology		Title 41 Permit	ADNR
		Fish Passage	ADNR
		Fishery Research. (Field Studies)	ADF&G
Solid/Hazardous Waste		Hazardous Waste Permit	EPA
		Hazardous Waste Transportation	US DOT
Land Use	Certificates of Approval for Dam Construction and Operation		ADNR

6.7 Summary

An analysis of the current design basis indicates that a proposed gasification and F-T facility at the Emma Creek Site is feasible in terms of current environmental permitting and compliance requirements imposed by Federal and State regulations. Detailed environmental compliance strategies and mitigation measures would need to be developed in concert with design details and operational plans and would include features necessary for proximity to the Denali Wilderness, which is a Class 1 area.

7. SUMMARY AND CONCLUSIONS

7.1 Alaska Coal Gasification Study

This study evaluated the technical and economic viability of a gasification and liquid fuels production plant to be sited near existing coal mining operations in Healy, Alaska. Liquid products from the plant would primarily be marketed to Alaskan refineries for use in producing commodities for in-state use.

7.1.1 Site Conditions

The Healy CTL site is located on leased land about six miles north of Usibelli's current coal mining operations at Two Bull Ridge. A new mining operation near Jumbo Dome would be developed to supply coal to the facility. For a gasification and F-T plant sized to use four million tons per year of coal, the Jumbo Dome deposits would last for more than 50 years. Further, the site is three miles from the Alaska Intertie, enabling excess power to be marketed on the grid. Impoundments on Emma and Marguerite Creeks would provide process and cooling water.

7.1.2 Product Markets

The F-T plant would produce 14,640 barrels of very low-sulfur liquid products per day, which could be used by in-state refineries to blend with their feedstocks and replace high-sulfur crude oil. Potential customers include the Flint Hills and PetroStar refineries in North Pole, the PetroStar refinery in Valdez, and the Tesoro refinery in Nikiski. The North Pole refineries can be supplied directly by rail, while the Nikiski and Valdez refineries would require a combination of rail and barge transport, or possibly the Nikiski refinery could be supplied by rail and pipelines.

Plant by-products could also be marketed. Sulfur, separated from the process stream, is a commodity that could be sold into the export market. However, because the Alaskan market is limited, sulfur would be shipped by rail to a port and shipped to the lower 48 states or the Pacific Rim. Slag from the gasifiers is inert and non-toxic. While it is possible that some could be shipped via rail to the Anchorage area and used for road construction and aggregate, this study assumed that the slag would be used as backfill at the mine site.

Electric power represents another marketable by-product. Based on the proposed plant configuration, 42.5 MW of power could be exported to the Alaskan grid.

7.1.3 Plant Design

Key components of the Healy Coal-to-Liquids Gasification plant include:

1. Slurry-fed gasification using coal as feedstock.
2. 95% purity oxygen production using a cryogenic air separation unit (ASU)
3. Syngas cooling and slag removal at gasifier outlet
4. Syngas scrubbing for chlorides removal
5. COS+HCN hydrolysis
6. Mercury removal using activated carbon beds
7. Crystasulf acid gas removal with sulfur polisher

8. Fisher-Tropsch liquid fuels production including off-gas recycle and additional hydrotreating
9. Power production, with excess power exported to the grid

The Healy Coal-to-Liquids Plant would use indigenous coal to produce more than 14,600 bbl/day of F-T liquids for offsite shipment by rail. Alaskan refineries are of sufficient size to use all of the F-T product, eliminating the need for F-T exports from the state. Estimated shipping costs to customer refineries range from $2 to 6/bbl depending on final destination.

7.1.4 Economic Analysis

The most challenging aspect in estimating the financial performance of the plant is predicting the future value of the F-T liquid products. The sensitivity analysis showed that the liquids value, plant EPC cost, and plant availability would have the largest impact on ROI (return on investment), with the liquids value being of greatest significance. The liquid product must be priced at $66 to $70/bbl to obtain a reasonable ROI for equity participants. Based on average 2005 to April 2007 refined product prices in Alaska, obtaining such prices could be possible. Before moving forward with the project, however, developers should identify specific markets for the F-T product, determine how the barrels will be priced relative to crude oil, and estimate likely scenarios for future product values.

Reflecting the uncertainty in the project at this stage of the design, conservative cost estimates have been developed for the plant by adding contingencies. Future estimates should focus on the areas of greatest uncertainty, namely the gasification and F-T sections of the plant, to develop the most accurate cost estimate possible.

CO_2 from the plant could be sequestered at a cost of $0.42/Mscf (~$7/ton). If the CO_2 has no economic value, as is assumed for this report, and all other plant variables remain unchanged, then the ROI for the Healy GTL plant would drop to 9.7%

7.1.5 Environmental Permits and Issues

An analysis of the current design basis indicates that a proposed gasification and F-T facility is feasible in terms of current environmental permitting and compliance requirements imposed by federal and State regulations. Detailed environmental compliance strategies and mitigation measures would need to be developed in concert with design details and operational plans.

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APPENDIX A MAJOR EQUIPMENT LIST

ACCOUNT 1 COAL HANDLING

ACCOUNT 1A COAL RECEIVING AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	200 ton	4
2	Feeder	Vibratory	450 tph	4
3	Conveyor No. 1	54" belt	450 tph	2
4	Conveyor No. 2	54" belt	450 tph	2
5	As-Received Coal Sampling System	Two-stage	N/A	2
6	Reclaim Hopper	N/A	40 ton	4
7	Feeder	Vibratory	300 tph	4
8	Conveyor No. 3	48" belt	300 tph	2
9	Crusher Tower	N/A	300 tph	2
10	Coal Surge Bin w/ Vent Filter	Compartment	300 ton	2
11	Crusher	Granulator reduction	6"x0 - 3"x0	4
12	Crusher	Impactor reduction	3"x0 - 1¼"x0	4
13	As-Fired Coal Sampling System	Swing hammer		4
14	Conveyor No. 4	48" belt	300 tph	2
15	Transfer Tower	N/A	300 tph	2
16	Tripper	N/A	300 tph	2
17	Coal Silo w/ Vent Filter and Slide Gates	N/A	2,500 ton	4

ACCOUNT 2 COAL PREPARATION AND FEED

ACCOUNT 2A FUEL SLURRY PREPARATION AND FUEL INJECTION

Equipment No.	Description	Type	Design Condition	Qty
1	Vibratory Feeder		140 tph	3
2	Conveyor No. 1	Belt	300 tph	2
3	Conveyor No. 2	Belt	300 tph	2
4	Rod Mill Feed Hopper	Vertical, double hopper	300 tons	2
5	Vibratory Feeder		200 tph	4
6	Weight Feeder	Belt	200 tph	4
7	Rod Mill	Rotary	200 tph	4
8	Slurry Water Storage Tank with Agitator	Field erected	200,000 gal	2
9	Slurry Water Pumps	Horizontal, centrifugal	1,200 gpm	4
10	Rod Mill Product Tank with Agitator	Field erected	200,000 gal	2
11	Rod Mill Product Pumps	Horizontal, centrifugal	2,000 gpm	4
12	Slurry Storage Tank with Agitator	Field erected	350,000 gal	2
13	Centrifugal Slurry Pumps	Horizontal, centrifugal	3,000 gpm	4
14	PD Slurry Pumps	Progressing cavity	500 gpm	8
15	Slurry Blending Tank with Agitator	Field erected	100,000 gal	2
16	Slurry Blending Tank Pumps	Horizontal, centrifugal	450 gpm	4

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

ACCOUNT 3A CONDENSATE AND FEEDWATER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty
1	Condensate Storage Tank	Vertical, cylindrical, outdoor	25,000 gal	2
2	Condensate Pumps	Vertical canned	900 gpm @ 400 ft	2
3	Deaerator (integral with HRSG)	Horizontal spray type	350,000 lb/h 200°F to 240°F	2
4	LP Feed Pump	Horizontal centrifugal single stage	150 gpm/1,000 ft	2
5	HP Feed Pump	Barrel type, multi-staged, centrifugal	1,000 gpm @ 5,500 ft & 150 gpm @ 1,700 ft	2

ACCOUNT 3B MISCELLANEOUS EQUIPMENT

Equipment No.	Description	Type	Design Condition	Qty
1	Auxiliary Boiler	Shop fabricated, water tube	400 psig, 650°F 70,000 lb/h	1
2	Service Air Compressors	Reciprocating, single stage, double acting, horizontal	100 psig, 750 cfm	2
3	Inst. Air Dryers	Duplex, regenerative	750 cfm	1
4	Service Water Pumps	Horizontal centrifugal, double suction	200 ft, 1,200 gpm	2
5	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	70 ft, 1,200 gpm	2
6	Fire Service Booster Pump	Two-stage horizontal centrifugal	250 ft, 1,200 gpm	1
7	Engine-Driven Fire Pump	Vertical turbine, diesel engine	350 ft, 1,000 gpm	1
8	Raw Water Pumps	SS, single suction	60 ft, 300 gpm	2
9	Filtered Water Pumps	SS, single suction	160 ft, 120 gpm	2
10	Filtered Water Tank	Vertical, cylindrical	15,000 gal	1
11	Makeup Demineralizer	Anion, cation, and mixed bed	70 gpm	2
12	Sour Water Stripper System	Vendor supplied	200,000 lb/h sour water	1
13	Liquid Waste Treatment System	Vendor supplied	400 gpm	1

ACCOUNT 4 GASIFIER AND ACCESSORIES

ACCOUNT 4A GASIFICATION (total for plant)

Equipment No.	Description	Type	Design Condition	Qty
1	Gasifier	Pressurized, two-stage entrained bed	2,500 ton/day/ 515 psia	4
2	Raw Gas Cooler	Fire-tube boiler	1,800 psig/635°F (drum) 600,000 lb/hr syngas	4
3	Raw Gas Cyclone	High efficiency	600,000 lb/h, syngas gas	4
4	Candle Filter	Pressurized filter with pulse jet cleaning	600 candles 60/40x1500 mm	4
5	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	600,000 lb/h, medium-Btu gas	4

ACCOUNT 4B AIR SEPARATION PLANT (total for plant)

Equipment No.	Description	Type	Design Condition	Qty
1	Air Compressor	Centrifugal, multi-stage	125,000 scfm, 199 psia discharge pressure	4
2	Cold Box	Vendor Design	3,700 ton/day O_2	2
3	Oxygen Compressor	Centrifugal, multi-stage	50,000 scfm, 563 psia discharge pressure	2
4	Nitrogen Compressor	Centrifugal, multi-stage	100,000 scfm, 300 psia discharge pressure	2

ACCOUNT 5 SYNGAS CLEANUP

ACCOUNT 5A COS HYDROLYSIS, MERCURY REMOVAL, ACID GAS REMOVAL AND SULFUR RECOVERY

Equipment No.	Description	Type	Design Condition	Qty
1	COS Hydrolysis Reactor	Activated alumina packed bed	500,000 lb/hr syngas, 450 psia, 350°F	4
2	Mercury Adsorber	Packed bed of sulfur impregnated activated carbon	500,000 lb/hr syngas, 450 psia, 350°F 9.5 ft ID x 24 ft	4
3	CrystaSulf Unit	Vendor design	350,000 lb/hr, 400 psia, 100°F 5 TPD Sulfur	4
4	Sulfur Polisher	Zinc oxide packed bed	350,000 lb/hr, 400 psia, 100°F	4

ACCOUNT 5B FISCHER-TROPSCH PROCESS

Equipment No.	Description	Type	Design Condition	Qty
1	Sulfur Polisher	ZnO packed bed	500,000 lb/hr Syngas, 719 psia	3
2	F-T Synthesis Reactor	Slurry reactor	500,000 lb/hr Syngas, 600 psia	3
3	CO_2 Removal Process	Proprietary amine	3,700 TPD CO_2	3
4	Hydrocarbon Recovery	Fractionator	125,000 lb/hr	3
5	Hydrogen Recovery	PSA	1,300 lb/hr H_2	3
6	Recycle Compressor	Reciprocal	50,000 lb/hr	3
7	Autothermal Reactor	Self-heating catalytic	25,000 lb/hr	3
8	Naphtha Hydrotreating	Catalytic bed	15,000 lb/hr	3
9	Distillate Hydrotreating	Catalytic bed	15,000 lb/hr	3
10	Wax Hydrotreating	Catalytic bed	45,000 lb/hr	3

ACCOUNT 6 COMBUSTION TURBINES AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	28.9 MWe Gas Turbine Generator	Axial flow, single spool based on GE LM2500	900 lb/sec airflow 2350°F rotor inlet temp.; 15.2:1 pressure ratio	2
2	Enclosure	Sound attenuating	85 dB at 3 ft	1
3	Air Inlet Filter/Silencer	Two-stage	900 lb/sec airflow 3.0 in. H_2O pressure drop, dirty	1
4	Starting Package	Electric motor, torque converter drive, turning gear	2,000 hp, time from turning gear to full load ~30 minutes	1
5	Air to Air Cooler			1
6	Mechanical Package	CS oil reservoir and pumps dual vertical cartridge filters air compressor		1
7	Oil Cooler	Air-cooled, fin fan		1
8	Electrical Control Package	Distributed control system	1 sec. update time 8 MHz clock speed	1
9	Generator Glycol Cooler	Air-cooled, fin fan		1
10	Compressor Wash Skid			1

ACCOUNT 7 WASTE HEAT BOILER, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition	Qty
1	Heat Recovery Steam Generator	Drum, multi-pressure, with economizer section and integral deaerator	HP-1600 psig/ 1000°F	1
2	Stack	Carbon steel plate, type 409 stainless steel liner	213 ft high x 12 ft dia.	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Qty
1	158 MW Steam Turbine Generator	TC2F26	1600 psig 1000°F/1000°F	1
2	Bearing Lube Oil Coolers	Plate and frame		2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop		1
4	Control System	Digital electro-hydraulic	1600 psig	1
5	Generator Coolers	Plate and frame		2
6	Hydrogen Seal Oil System	Closed loop		1
7	Surface Condenser	Single pass, divided waterbox	100,000 lb/h steam @ 2.4 in. Hga	1
8	Condenser Vacuum Pumps	Rotary, water sealed	1,000/25 scfm (hogging/holding)	2

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	Circ. Water Pumps	Vertical wet pit	200,000 gpm @ 60 ft	2
2	Cooling Tower	Mechanical draft	50,000 gpm	1

ACCOUNT 10 SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Qty
1	Slag Quench Tank	Water bath	12 tph	4
2	Slag Crusher	Roll	12 tph	4
3	Slag Depressurizer	Proprietary	12 tph	4
4	Slag Handling Tank	Horizontal, weir	6 tph	8
5	Slag Conveyor	Drag chain	6 tph	8
6	Slag Separation Screen	Vibrating	50 tph	*1
7	Coarse Slag Conveyor	Belt/bucket	50 tph	*1
8	Fine Ash Storage Tank	Vertical	50,000 gallons	*1
9	Fine Ash Transfer Pumps	Horizontal/centrifugal	200 gpm	2
10	Storage Bin	Vertical	5,000 tons	*1
11	Unloading Equipment	Telescoping chute	50 tph	*1

*Total for plant.

APPENDIX B FINANCIAL MODEL INPUTS

Financial Model Entries—Plant Inputs
(Entries used to obtain a 12% ROI)

Project Name	Healy FT
Project Location	Alaska
Primary Output/Plant Application **(Options: Power, Multiple Outputs)**	Multiple Outputs
Primary Fuel Type (**Options: Gas, Coal, Petroleum Coke, Other/Waste)**	Coal
Secondary Fuel Type (**Options: None, Gas, Coal, Petroleum Coke, Other/Waste)**	None
Plant Output and Operating Data : Note - All ton units are US Short Tons (2000 lbs)	
Syngas Capacity (MMcfd/Day)	0
Gross Electric Power Capacity (MW)	178
Net Electric Power Capacity (MW)	43
Steam Capacity (Tons/Hr)	0
Hydrogen Capacity (MMcfd/Day)	0
Carbon Dioxide Capacity (MMcfd/Day)	204
Elemental Sulfur Capacity (Tons/Day)	18
Slag Ash Capacity (Tons/Day)	1,228
Fuel (Tons/Day)	0
FT Liquids (Barrels/Day)	14,640
Environmental Credit (Tons/Day)	0
Overall Capacity Factor (includes planned and unplanned outages)	85%
Enter One of the Following Items(For Each Primary/Secondary Fuel) Depending on Project Type:	
Primary Fuel Heat Rate (Btu/kWh) based on HHV **FOR POWER PROJECTS**	0
Secondary Fuel Heat Rate (Btu/kWh) based on HHV **FOR POWER PROJECTS**	0
Primary Fuel Annual Fuel Consumption (Tons/Day) **FOR NON POWER PROJECTS**	11,700
Secondary Fuel Annual Fuel Consumption (in Tons/Day) **FOR NON POWER PROJECTS**	0
Initial Capital and Financing Costs (enter 'Additional Costs' in thousand dollars)	
EPC (in thousand dollars)	1,429,047
Owner's Contingency (% of EPC Costs)	25%
Process Contingency (% of Tech. Uncertain EPC Costs)	9.8%
Portion of Plant that is Technologically Uncertain	25%
Start-up (% of EPC Costs)	2%
Owner's Cost (in thousand dollars)	142,905
Operating Costs and Expenses	
Variable O&M (% of EPC Cost)	1.5%
Fixed O&M Cost (% of EPC Cost)	3.5%

Capital Structure		
Percentage Debt	70%	
Percentage Equity	30%	
Project Debt Terms		
Loan 1: Senior Debt		
% of Total Project Debt **(total for Loans 1, 2, and 3 must = 100%)**	100%	
Interest Rate	8%	
Financing Fee	3%	
Repayment Term (in Years)	15	
Grace Period on Principal Repayment	1	
First Year of Principal Repayment	2012	
Loan Covenant Assumptions		
Interest Rate for Debt Reserve Fund (DRF)	4%	
Debt Reserve Fund Used on Senior Debt **(Options: Yes or No)**	No	
Depreciation : "SL" for Straight-Line or "DB" for 150% Declining Balance		**Method**
Construction (Years) : *Note - DB Method Must be 15 or 20 years*	15	SL
Financing (Years) : *Note - DB Method Must be 15 or 20 years*	15	SL
Working Capital		
Days Receivable	30	
Days Payable	30	
Annual Operating Cash (Thousand $)	$100	
Initial Working Capital (% of first year revenues)	7%	
ECONOMIC ASSUMPTIONS		
Cash Flow Analysis Period		
Plant Economic Life/Concession Length (in Years)	30	
Discount Rate	12%	
Escalation Factors		
Project Output/Tariff		
Electricity Energy Payment	2.4%	
FT Liquids	3.0%	
Elemental Sulfur	3.0%	
Slag Ash	3.0%	
Fuel/Feedstock		
Coal	2.0%	
Operating Expenses and Construction Items		

Variable O&M	2.0%	
Fixed O&M	2.0%	
Other Non-fuel Expenses	2.0%	
EPC Costs	2.0%	
Tax Assumptions		
Tax Holiday (in Years)	0	
Income Tax Rate	37%	
Subsidized Tax Rate (used as investment incentive)	0%	
Length of Subsidized Tax Period (in Years)	0	

FUEL/FEEDSTOCK ASSUMPTIONS				
Fuel Prices : For the Base Year, then escalated by fuel factors above				
Coal ($/US Short Ton)	15.30			
Alternatively, use Forecasted Prices (From Fuel Forecasts Sheet)? (Yes/No)	No			
TARIFF ASSUMPTIONS				
INITIAL TARIFF LEVEL (In Dollars in the first year of construction)				
Electricity Payment ($/MWh)	46			
FT Liquids ($/Barrel)	64.1			
Elemental Sulfur ($/US Short Ton)	63			
Carbon Dioxide ($/MSCF)	0			
Slag Ash ($/US Short Ton)	0			
CONSTRUCTION ASSUMPTIONS				
Construction Schedule	**A**			
Construction Start Date	7/1/2007			
Construction Period (in months)	42			
Plant Start-up Date *(must start on January 1)*	1/1/2011			
EPC Cost Escalation in Effect? (Yes/No)	7/1/2007			
Percentage of Cost for Construction Periods	**Four Year Period**			
Enter for Five, Four or Three Year Periods (To the Right --->)	**Year 1**	**Year 2**	**Year 3**	**Year 4**
Capital Costs: Unescalated Allocations	15.0%	30.0%	30.0%	25.0%
Initial Working Capital	0.0%	0.0%	0.0%	100.0%
Owner's Contingency (% of EPC Costs)	0.0%	0.0%	0.0%	100.0%
Development Fee (% of EPC Costs)	35.0%	35.0%	30.0%	0.0%
Start-up (% of EPC Costs)	0.0%	30.0%	70.0%	0.0%
Initial Debt Reserve Fund	0.0%	30.0%	70.0%	0.0%

Owner's Cost (in thousand dollars)	0.0%	30.0%	70.0%	0.0%
Interest During Construction	0.0%	30.0%	70.0%	0.0%
Financing Fee	0.0%	30.0%	70.0%	0.0%
Plant Ramp-up Option (Yes or No)	Yes			
Start-Up Operations Assumptions (% of Full Capacity)				
Year 1, First Quarter	60%			
Year 1, Second Quarter	70%			
Year 1, Third Quarter	80%			
Year 1, Fourth Quarter	85%			
Year 1 Average Capacity %	74%			
Year 2, First Quarter	85%			
Year 2, Second Quarter	85%			
Year 2, Third Quarter	85%			
Year 2, Fourth Quarter	85%			
Year 2 Average Capacity %	85%			

APPENDIX C APPLICABLE FEDERAL STATE AND LOCAL PERMITTING ACTIVITIES

Permit/Activity	Authority	Description	Potential Applicability to Project
APPLICABLE FEDERAL ENVIRONMENTAL PERMITS AND PERMITTING ACTIVITIES			
U.S. Environmental Protection Agency (USEPA)			
National Pollutant Discharge Elimination System (NPDES): Point Source and Stormwater Discharges	Section 402, Clean Water Act (CWA) (22 USC § 1251 et seq.)	Point source and stormwater discharges to surface waters including industrial and domestic wastewater, gravel pit and construction dewatering, hydrostatic test water, and storm water discharges.	Stormwater, domestic, and industrial wastewater
Discharge of Fill Material	Section 404, CWA (33 USC § 1251 et seq.)	USEPA reviews and comments on USACE Section 404 permit applications for compliance with the Section 404(b)(1) guidelines and other statutes and authorities within its jurisdiction (40 CFR 230).	Wetland and waters fill/ structures
SPCC Plan	Section 311, CWA (33 USC § 1251 et seq.)	USEPA requires a spill prevention, control, and countermeasure (SPCC) plan to be developed by owners or operators of any facility storing a total capacity of 1,320 gallons of fuel in aboveground storage tanks.	Fuel Storage Tanks
Underground Injection Control (UIC)	Safe Drinking Water Act (42 USC § 300)	Regulates implementation of Class I and Class V injection wells in Alaska for injection of non-hazardous and hazardous waste.	Injection of wastes (unlikely)
Cultural and Historical Resource Preservation	Section 106, National Historic Preservation Act of 1966 (NHPA) (16 USC § 470 et seq.)	Ensure consideration of the values of historic properties in carrying out federal activities, and to make efforts to identify and mitigate impacts to significant historic properties.	Review of NPDES activity
Hazardous Waste Generator and Transporter	Sections 3001 through 3019, Resource Conservation and Recovery Act (RCRA) (42 USC § 3251 et seq.)	Establishes criteria governing the management of hazardous waste	Management of hazardous waste

Permit/Activity	Authority	Description	Potential Applicability to Project
APPLICABLE FEDERAL ENVIRONMENTAL PERMITS AND PERMITTING ACTIVITIES			
U.S. Army Corps of Engineers (USACE)			
Dredge and Fill Permit	Section 10, Rivers and Harbors Act (33 USC § 403)	Regulates and permits dredging, filling and structures in, on, over, or under navigable waters of the United States.	Wetland and water dredging, filling, structures for facilities
Discharge of Fill Material	Section 404, CWA (33 USC § 1251 et seq.)	Placement of dredge and fill material (including structures) in waters of the United States, including wetlands.	Wetland waters, filling and structures for a facilities
Section 106, National Historic Preservation Act	Section 106, National Historic Preservation Act of 1966 (NHPA) (16 USC § 470 et seq.)	During construction, ensures consideration of the values of historic properties in carrying out federal activities, and to make efforts to identify and mitigate impacts to significant historic properties.	Review of Section10/404 activity
U.S. Department of Transportation (USDOT)			
Hazardous Materials Registration Number	Hazardous Materials Transportation Act (49 CFR)	Transportation of hazardous materials to or from facilities.	Hazardous waste disposal from operations.
U.S. Fish and Wildlife Service (USFWS)			
Endangered Species Act Section 7 Consult	Endangered Species Act (ESA) (16 USC § 1531)	Protects wildlife, fish, and plant species in danger of becoming extinct, and to conserve the ecosystems on which endangered and threatened species depend.	Construction and operations
Bald Eagle Protection Act Clearance	Bald and Golden Eagle Protection Act (16 USC § 668)	Makes it unlawful to take, pursue, molest, or disturb bald and golden eagles, their nests, or their eggs.	Construction and operations
Migratory Bird Protection Act Consultation	Migratory Bird Treaty Act (Title 16 USC § 703)	Protect birds that have common migration patterns between the United States and Canada, Mexico, Japan, and Russia.	Construction and operations
Fish & Wildlife Coordination Act Consultation	Fish and Wildlife Coordination Act (FWCA) (16 USC § 661 et seq.)	Protection of wildlife resources and habitat.	Construction and operations

Permit/Activity	Authority	Description	Potential Applicability to Project
APPLICABLE FEDERAL ENVIRONMENTAL PERMITS AND PERMITTING ACTIVITIES			
Alaska Department of Natural Resources (ADNR)			
Certificates of Approval to Construct and Operate a Dam	AS 46.17 and 11 AAC 93 Article 3	Authorizations required for dams that impound more than 50 acre ft of water and are 10 ft high or greater; are 20 ft high; or would threaten lives and property if it failed. Operations certificate requires Emergency Action Plan.	Required for construction and operation of dam
Temporary Water Use Permit (TWUP)	AS 46.15	Temporary uses of a significant volume of water, for up to 5 years during development or operation of a project require a Temporary Water Use Permit. The permit is issued by the ADNR/MLW/Water Section.	Required for temporary water use
Permit to Appropriate Water (Water Rights)	AS 46.15	Appropriation of a significant amount of water on other than a temporary basis requires authorization by a Water Rights Permit. A water rights permit is a legal right to use a specific amount of surface or groundwater from a specific source. This water can be diverted, impounded, or withdrawn for a specific use. When a water right is granted, it becomes appurtenant to the land where the water is being used for as long as the water is used.	Required
Material Sale	AS 38.05 and 020	If materials such as sand, gravel, or rock, are needed from state lands off a millsite lease or road right-of-way, then a separate material sale is issued by the ADNR/MLW/Lands Section.	Unlikely
Cultural Resource Protection	Section 106, National Historic Preservation Act of 1966 (NHPA)	Clearance must be obtained to ensure that a project will not significantly impact cultural and archaeological resources. If significant disturbance cannot be avoided, then a compensation strategy is developed. Cultural resource clearances are obtained from ADNR/State Historic Preservation Office.	Required for site development
Title 41 Permit	AS 16.05.840 or 16.05.870	This permit, regardless of land ownership, is required for any activity conducted within fish-bearing waters, such as docks, material sites, and water-withdrawal structures. The ADNR/OHMP issues this permit.	Required for construction and operation
Burn Permit	AS 41.15.050 and AS 41.15.060	Small piles less than 10 ft. in diameter are considered Class A burns and permitting is required for these burns between May 1 and September 30 of each year. For piles greater than 10 ft. in diameter or burns one acre or larger, inspection and permitting are required. The ADNR/Division of Forestry issues this permit.	Required for construction
Fish Passage	AS 16.05.840 (Fishway Act) and AS 41.14	The Fishway Act requires that an individual or governmental agency notify and obtain authorization from the Alaska Department of Natural Resources (ADNR) for activities within or across a stream used by fish if the department determines that such uses or activities can represent an impediment to the efficient passage of fish. Culvert installation; stream realignment or diversions; dams; low-water crossings; and construction, placement, deposition, or removal of any material or structure below ordinary high water all require approval from the ADNR. Although approval is	Required for construction and operation

Permit/Activity	Authority	Description	Potential Applicability to Project
APPLICABLE FEDERAL ENVIRONMENTAL PERMITS AND PERMITTING ACTIVITIES			
		by the ADNR/OHMP, an ADF&G Fish Habitat Biologist will review and make recommendation.	
Alaska Department of Environmental Conservation (ADEC)			
Solid Waste Permits and a Comprehensive Solid Waste Management Plan	AS 44.46, AS 46.03, AS 46.04, and AS 46.06	During construction and operation, the project may require solid waste disposal permits for inert waste, wood waste, industrial solid waste, coal ash, hazardous waste, polluted soil, building demolition waste containing asbestos, building demolition waste, and construction waste. This means, this project may then require development and submittal of a comprehensive solid waste management permit in lieu of individual permits. Permits and/or a solid waste management plan are approved by the ADEC/Division of Environmental Health /Solid Waste Program to operate the solid waste management system.	At a minimum, for incinerated domestic waste and sewage, inert waste, wood waste, and construction waste
Section 401 Certification	Section 401, CWA	Storm water discharges are regulated under the NPDES program and certain storm water discharges require an NPDES permit from EPA. Under the NPDES program the state of Alaska does not have permitting and enforcement authority. However, pursuant to Section 401 of the Clean Water Act (CWA) the state of Alaska certifies EPA general permits both construction activities and during operational phases. This is commonly known as "401 Certification". The facility may have separate NPDES permits to cover waste water and storm water discharges, or the requirements may be combined into one permit.	Required for construction and operation
Certificate of Reasonable Assurance for 402 and 404 Permits	Section 402 and 404, CWA	Activities involving discharge of wastewater or fill material into waters of the United States are not only governed by the terms and conditions of a CWA Section 402 NPDES Permit from EPA, and a CWA Section 404 Permit from the COE, but also require a Certificate of Reasonable Assurance from the State of Alaska. These certificates can only be issued if ADEC/Division of Water can state that the proposed activity will comply with Section 401 of the CWA and that any discharge will comply with applicable state water quality standards.	Required for construction and operation
Approval to Construct and Operate a Public Water Supply System.	18 AAC 70 and 18 AAC 72	Prior to start of construction, ADEC/Division of Water must approve detailed engineering reports, plans, and specifications for the construction, alteration, or modification of a public water system. Once construction has been completed, ADEC must approve operation of a public water system.	Required for construction and operation of Potable water supply
Plan Review for Non-Domestic Wastewater Treatment System	18 AAC 72 or Section 401 Certification	Plans for treatment of wastewater from non-domestic wastewater sources must be submitted to the ADEC/Division of Water. Approval follows, either as an ADEC Wastewater Disposal Permit (18 AAC 72) or an NPDES Permit (ADEC reviews plans under CWA Section 401).	Required for construction and operation of terminal wastewater system

Permit/Activity	Authority	Description	Potential Applicability to Project
APPLICABLE FEDERAL ENVIRONMENTAL PERMITS AND PERMITTING ACTIVITIES			
Plan Review and Construction Approval for Domestic Sewage System.	18 AAC 72	The construction and operation of facilities that collect, treat, and dispose of wastewater is governed by a plan review to ensure that minimum standards are applied. Detailed engineering reports, plans, and specifications must be certified by a registered Professional Engineer. These are then submitted for approval by the ADEC/Division of Water.	Required for construction and operation of domestic wastewater system
Spill Prevent, Control and Countermeasure (SPCC) Plan Review	40 CFR 112.1-7.	ADEC will use its CWA Section 401 certification authority to review the SPCC Plan required by EPA for storage of large quantities of oil.	Required for fuel storage areas
Oil Discharge Prevention and Contingency Plan Review and Approval.	18 AAC 75.455	Approval of an oil discharge contingency plan is required prior to commencement of operation of vessels and oil barges on state waters, or for oil terminal facilities capable of storing more than 1,320 gallons above ground or more than 42,000 gallons underground. These contingency plans are reviewed and approved every 3 years by the ADEC/Division of Spill Prevention and Response/ Industry Preparedness Program	Required for fuel storage areas
Air Quality Control Permits	18 AAC 50	The construction, modification, and operation of facilities that produce air pollutants require state Air Quality Control Permits. Depending on the activity, projects could require Title I Construction, Title I Minor, and/or Title V operating permits. The determination to require permits is based on the total emissions and/or project emissions. Generally, air quality must be maintained at the lowest practical concentrations of contaminants specified in the Ambient Air Quality Standards of 18 AAC 50.020(a).	Title I Construction Permit and Title V Operating Permit will be required
Air Quality Open Burn Approval	18 AAC 50.065	An open burn approval is required for open burning of woody debris if the intent is to clear and burn from 40 acres or more in a year. Whereas the ADNR Burn Permit primarily is concerned with fire control, this ADEC permit primarily is concerned with air quality.	Required during construction
Food Sanitation Permits	AS 46.03.20	Construction and operation of permanent, temporary, and mobile food services is governed and permitted by the ADEC/Division of Environmental Health/Food Safety and Sanitation Program.	Food services during construction and operation will require permits
Alaska Department of Fish and Game (ADF&G)			
Fish Resources Permit	5 AAC 41	This permit is required of anyone who wants to collect or hold alive any live fish, shellfish, or aquatic plants or their gametes (except gold fish and decorative tropical fish) for purposes of science, education, propagation, or exhibition. It is issued by the ADF&G/Division of Sports Fish, and ADF&G/Division of Commercial Fisheries.	Required during baseline studies for dam

Permit/Activity	Authority	Description	Potential Applicability to Project
APPLICABLE FEDERAL ENVIRONMENTAL PERMITS AND PERMITTING ACTIVITIES			
Denali Borough			
(no required permits identified)			