An SAIC Report Prepared for
The Indiana Center for Coal Technology Research

Coal Gasification and Liquid Fuel – An Opportunity for Indiana

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ºC	Degrees Celsius
ºF	Degrees Fahrenheit
$	United Stated dollars
%	Percent
ASME	American Society of Mechanical Engineers
ASU	Air Separation Unit
ATR	Auto Thermal Reformer
B	Billion
BACT	Best Available Control Technology
bbl	Barrels
bbl/day	Barrels of Synthetic Fuel per Day
bpd	Barrels Per Day
BRAC	Base Realignment and Closing
Btu	British Thermal Unit(s)
Ca	Calcium
CBTL	Coal/Biomass To Liquid
CCS	Carbon Capture and Storage
CCTR	Center for Coal Technology Research
CFR	Code of Federal Regulations
CH_4	Methane
Cl	Chlorine
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COS	Carbonyl Sulfide
CTL	Coal to Liquids
d	Day
D/E	Debt-Equity
DoD	Department of Defense
DOE	Department of Energy
EOR	Enhanced Oil Recovery
ESR	Enhanced Shale Recovery
ECBM	Enhanced Coal Bed Methane
EIA	Energy Information Agency
EPC	Erected Plant Cost
ESA	Environmental Site Assessment
EU	European Union
FY	Fiscal Year
F-T	Fischer-Tropsch
ft	Foot (Feet)

gal	Gallon(s)
GE	General Electric
GHG	Greenhouse Gas
H_2/CO	Hydrogen to Carbon Monoxide Synthesis Gas Ratios
H_2O	Water
H_2S	Hydrogen Sulfide
HHV	High(er) Heating Value
hr	Hour(s)
HW	Hazardous Waste
IDB	Industrial Development Bond
IDEM	Indiana Department of Environmental Management
IDNR	Indiana Department of Natural Resources
IAC	Indiana Administrative Code
IGCC	Integrated Gasification Combined-Cycle
INDOT	Indiana Department of Transportation
ITM	Ion Transport Membrane
K	Potassium
kg	Kilogram
kW	Kilowatt
kWh	Kilowatt-Hour
lb	Pound(s)
m	Meter
MBtu	Million Btu
min	Minute(s)
Mj	Megajoule
MM	Million(s)
MMt	Million Metric Tons
mt	Metric ton
MW	Megawatts
MWth	Megawatt Hours
Na	Sodium
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
N/A	Not Applicable
NOx	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NSA	Naval Support Activity
OPEC	Organization of the Petroleum Exporting Countries
P	Phosphorus
P2	Pollution Prevention

ppbv	part per billion by volume
PSA	Pressure Swing Absorption
psia	Pounds per Square Inch Absolute
psig	Pounds per Square Inch Gauge
R&D	Research and Development
RCRA	Resource Recovery and Conservation
RFI	Request for Information
ROI	Return on Investment
SAIC	Science Applications International Corporation
scf	Standard Cubic Foot (Feet)
SNG	Synthetic Natural Gas
SO_2	Sulfur Dioxide
SPCC	Spill Prevention Control and Countermeasures
SRWC	Short Rotation Woody Crops
SWP3	Storm Water Pollution Prevention Plan
Syngas	Synthesis Gas
TPD	Tons Per Day
US	United States
USACE	United States Army Corp of Engineers
USDOE	United States Department of Energy
vol	Volume
wt	Weight
v/v-hr	Volume of CO Consumed per Volume of Catalyst per Hour
yr	Year

1.0 Executive Summary

1.1 Overview This report documents a Feasibility Study performed by SAIC under a grant provided by the Center for Coal Technology Research (CCTR) on December 24, 2007, and jointly funded by SAIC. This Feasibility study is part of an overall CCTR strategy, the intent of which is to advance the viability of coal-based energy technology in the State of Indiana. The Study provides a conceptual definition of a clean coal, environmentally responsible, energy facility that could be located in Southwestern Indiana, designed to maximize satisfaction of State and CCTR energy goals, and provide Naval Support Activity (NSA) Crane with independence from the national electrical grid during an emergency. In addition to electrical power, the plant concept would produce Coal To Liquid (CTL) transportation fuel using the Fischer-Tropsch (F-T) process. Our selected reference design is based on technology currently in use worldwide; although the F-T process has not been demonstrated at commercial scale in the United States. The facility concept would incorporate both commercial scale outputs and, in accordance with CCTR goals, the capability to do relevant coal-based commercial scale Energy Research and Development (R&D). The design concept would leverage existing coal gasification technology, generate a clean Synthesis Gas (Syngas) for power generation and the CTL process, and include the capability to capture CO_2. A baseline concept was selected and an evaluation carried out to provide technical and economic perspective, and represents a major segment of this document. Specific outputs of the study include facility and R&D design concepts; size and product outputs; process analysis; capital and operating cost estimates; a comparative business case analysis; and, analysis relative to the overall feasibility of such a project. An environmental impact analysis was also performed, and will be provided to the State under separate cover. The executive summary of the environmental report has been included as **Annex A** of this report.

1.2 Approach SAIC approached this study by defining criteria based on Indiana goals for a reference design facility concept that could then be evaluated for technical and economic feasibility. We concluded that a product/product mix needed to be determined early as such decisions drive facility design, process, and cost. The facility design criteria used in this study are as follows:

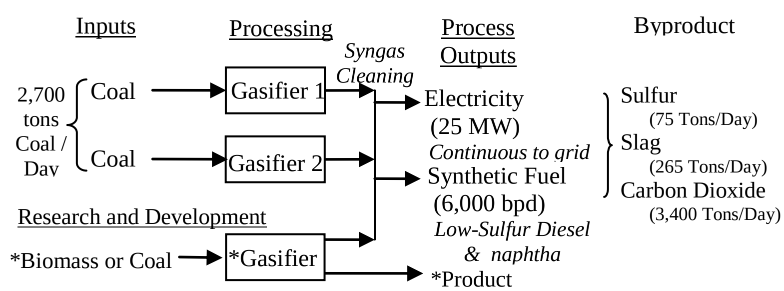
- Generate 25 Megawatts (MW) of continuous power to the local grid, sufficient to supply NSA Crane peak load, independent of the national grid
- Locate on or near NSA Crane to enhance Crane's value through future BRACs, and be supportable logistically (e.g. coal and water) at that location
- Facility must be large enough to be commercially viable
- Facility must be capable of meeting all existing environmental requirements, and adaptable to future legislative/regulatory requirements relative to greenhouse gases as solutions develop
- Suitable for coal-based Energy R&D up to and including commercial scale
- Adaptable to present and future Department of Defense (DoD) and Department of Energy (DOE) needs
- Projected capital investment of less that $1 billion

Within the context of our criteria, we performed a "quick look" business case, by modeling available facility size, product, and capital cost data; and by researching local and national product markets; and discussing product sales with potential credible customers.

We further characterized the types of R&D capability of primary interest to academia and industry. We were then able to develop a baseline facility design and business model, and perform a feasibility level economic and technical analysis around the baseline design.

1.3 Reference Feasibility Concept As part of our product analysis, we investigated local markets and determined that there is a foreseeable future market in Southwestern Indiana for liquid fuels including low sulfur diesel, and commercial electric power; although certainly other coal gasification products such as synthetic natural gas could also have been considered. A local market can also be projected for plant by-products including sulfur and slag; and early discussions indicate a potential local market for a significant percentage of CO_2 output. Our basic production design concept is a CTL facility based on commercial coal gasification and Fischer-Tropsch technologies. The small scale concept facility would be designed to process 2,700 tons of Indiana coal per day to produce 25 MW minimum continuous electric power delivered to the grid, or to Crane in an emergency, along with 6,000 barrels of synthetic fuel per day (bpd). A larger facility could present greater economic benefits, but would be difficult to support logistically on the base.

In our design concept, simply put, Indiana mined coal, Illinois Basin #6 enters the gasifier(s) as feedstock. Once in the gasifier(s), the temperature is increased and oxygen is added into the system. This process creates a carbon monoxide and hydrogen gas mixture. The impurities are removed from the gas mixture creating a clean Syngas. The Syngas is then fed to the F-T process to produce synthetic liquid fuels with the remaining fuel value in the gas used to produce electricity to run the facility, with a net electric power generation for sale to the commercial grid. **Figure 1.3-1** illustrates the basic process concept.



* - 3rd Gasifier-for future development

Figure 1.3-1: Simplified Coal Gasification Facility Design

1.4 Research and Development One of the State requirements was that the facility should be configured to accommodate future research and development of clean coal technologies. In order to meet these goals the following criteria should be considered:

- Include alternative materials storage, processing, and handling technologies
- Designate space and piping connections to accommodate the addition of a third gasifier
- Create slipstream access ports for raw product, final product, and byproduct sampling and testing
  - Available slipstreams for research could include but are not limited to hydrogen, Fischer-Tropsch processed liquids, clean and processed Syngas, and CO_2
- Provide grid and grid interface access for grid management and stability testing

- Incorporate extensive sensor and data capture systems for research, simulation, and training (on-site and remote)
- Provide labs, meeting, and classroom space for training available to both university and industry research and development teams

To reduce the CO_2 footprint of a CTL facility, one priority research area is evaluation of biomass as an input. Research suggests that a 10-30% biomass blend will significantly reduce the total CO_2 footprint. Our concept includes expansion space for installment of a third gasifier that could be used to conduct Coal/Biomass To Liquid (CBTL) research and development.

A facility of this size would be designed to satisfy all current environmental requirements, and to capture output CO_2 in an effort to respond to future legislative or regulatory requirements. Solution options include sale, enhanced oil recovery, long term sequestration, or other potential solutions such as algae-based. This facility would occupy approximately 200 acres to accommodate R&D and future possible capabilities, such as CBTL.

1.5 Site Selection Construction of a CTL facility requires adequate acreage; access to major highway, railway, electric, and pipeline infrastructure; facility security; a reliable water supply; and proximity to coal supply, potential product customers and sequestration geology. Properties near, adjacent to, or on NSA Crane meet all of these criteria. An off-base site, near enough to meet the Crane grid independence requirement, was selected as the basis for the feasibility study due to permitting, logistics, land use, and economic incentive advantages.

1.6 Environmental Considerations The State expressed strong interest in an environmentally friendly design. Planning focus was given to meeting or exceeding current State and Federal environmental standards, while positioning to meet potential new requirements.

Key environmental considerations included:

- Best practice emissions control
  - Sulfur and mercury removal
  - Heat recovery steam generator equipped for nitrogen oxide control
  - State of the art site design and control technologies used to manage storm water runoff from coal and biomass storage areas
- Maximum sale of byproducts (slag and sulfur, others if economic)
- Sustainable water consumption
- Capture of CO_2 output for
  - Commercial use
  - Potential geologic storage
  - Other technology solutions

1.7 Business and Financial Considerations

1.7.1 Capital and Operating Costs No commercial facilities of this type have been built in the United States from which costs can be extrapolated or benchmarked. Currently, construction costs are escalating rapidly making future cost estimates problematic. Our cost estimates are developed from the best available equipment and facility costs from commercial sources, SAIC internal estimates, and data available from the US Department of Energy's National Energy Technology Laboratory. We incorporated significant cost escalation and project and process contingency, but future volatility may be an issue. Cost estimates include all identifiable costs for the site and equipment to include CO_2 capture, but not sequestration. Construction of the reference design is today estimated at approximately $800 million. A variety of other project expenses, such as environmental permitting and financing, could bring the estimated total project cost to approximately $950 million.

Annual operating costs, including labor, overhead and taxes, maintenance materials, consumables, and coal are estimated at $90 million per year, over half of which is the cost of Indiana mined coal, Illinois Basin #6, estimated at $55/ton.

1.7.2 Revenue Considerations Recognizing that we are in an extremely volatile market period, this study utilized an array of conservative estimates (by July 2008 standards) for F-T product and by-product market prices (F-T ultra low sulfur diesel, naphtha, electricity, sulfur, slag, and CO_2). For example, we used the average (2008-2011) futures price for ultra low-sulfur diesel (as of March 3, 2008) of $2.89/gallon.

The resultant gross annual revenue for our reference facility running at 85 percent of its full capacity is estimated to be $210 million.

Using our estimated construction costs, this leads to an ROI of 18% with a payback period of approximately 11 years, and parallels the NETL report[1] which estimates that small scale CTL facilities are commercially viable at crude oil prices of $55-60 per barrel without sequestration. Due to the smaller scale of the plant in this study, and recent increases in construction costs, the crude oil price equivalent for this project is in the mid-$70s range, at 18% ROI and again without sequestration. A range of ROI calculations are provided in the report and are obviously sensitive to major variables, such as the price of crude oil, coal, and construction. For example, with crude oil prices in the $57-62 bbl range, this project would be expected to return a 10% ROI.

1.7.3 Business Model The basic business tenets of this feasibility study are that it address a small, scalable, commercially viable facility targeted to sell diesel and naphtha to local markets, offer grid independence to Crane, host a clean coal research center to support Indiana's coal and utility industries, and lends itself to replication and/or tailoring for different product outputs in different locations across the state of Indiana.

1.8 Risks The energy marketplace today presents a picture of unprecedented volatility. Successful technical and cost effective implementation of any project would require that vital risk areas be addressed and mitigated. These risk areas will require additional planning along parallel paths, and the development of solutions and mitigation approaches. Risk areas include, of course, the price of crude oil, potential CO_2 tax, regulation and/or Cap and Trade legislation; CO_2 sequestration management and/or other mitigation technology; first time systems engineering and integration; and construction and operations costs.

1.9 State of the Market and Timeline During the Military Energy and Fuels conference of April 29, 2008, NETL reported that there are 15 CTL plants being planned in the continental United States. Estimated costs of these plants range from $1B to $8B, with reportedly stated capacities from 5,000 bpd to 80,000 bpd. Status of these plants runs from early feasibility planning through design. This level of interest is obviously driven by the high price of crude oil, and the need for national energy independence, coupled with improved coal gasification technology, successful production of liquid fuels in South Africa and now China

[1] *Technical and Economic Assessment of Small-Scale Fischer-Tropsch Liquids Facilities,* DOE/NETL-2007/1253, Final Report for Subtask 41817.401.01.08.003, February 27, 2007.

(without CO_2 emission controls); and by the fact that our nation's huge coal reserves could supply our energy needs for over 200 years. New CTL initiatives continue to surface; for example, a $7.6B CTL plant in McCracken County, Kentucky, was announced in late June, as a high priority of the Governor to receive $550M in State incentives. This project would be built in four phases over 5 years, according to published reports. This may be a realistic timeline for construction, but upfront permitting, and other business and programmatic issues could add 1 to 2 years to the front end. Significant investor commitments for any CTL project will likely be delayed until after the new Administration and Congress determine if and how CO_2 emissions should be addressed, 12 to 18 months from now.

1.10 Conclusion This study concludes that while additional planning is required and risks exist in this volatile energy environment, this design concept and/or related concepts could be economically and technically viable, contingent upon the final state of these risk factors. An exception to this commercial viability would be the development of an R&D capability which would require substantial non-commercial subsidy. A larger facility in terms of product output could, as stated above, provide greater economic viability by taking advantage of economies of scale. Risk areas as described above that must be addressed include the price of crude oil; systems engineering and integration; construction and commodity costs including coal; and possible CO_2 tax, legislation, and regulation. The opportunity side is also large. Benefits could include reduced reliance on foreign oil, enhanced use of Indiana coal, more Indiana jobs, advances in technology and process, industry profitability, and creation of regional supply for transportation fuels.

Notwithstanding the risk and volatility of today's energy environment, a path to success for a CTL project in Southwestern Indiana can be envisioned as follows:

The price of crude oil remains high enough to support a business case for a CTL plant, even assuming an adjustment to a historically more appropriate exchange rate for the dollar and construction cost growth. The technical risk that this country has not demonstrated the ability to build a full cycle CTL plant is mitigated to a reasonable level by assembling the right team of "sub process" industry, academia and government experts, e.g. coal gasification, power generation, fuel refining, F-T process, construction, and CO_2 capture and transport, supported by a strong systems engineering capability. The nation's positions on CO_2 taxation and associated legislation and regulation are defined at achievable levels. Numerous initiatives which have been and are being mobilized to address CO_2 emissions, from utilizing algae beds to full scale geologic sequestration, via DARPA, DOE and State initiatives begin to achieve success. Indiana, for example, is a member of a DOE funded state regional coalition and is in turn funding an initial sequestration project in Southwest Indiana. In fact, a project with output the size of this concept design might not have to wait for a global solution to CO_2 management. As described, there are local CO_2 sale opportunities, and multi-state planning is ongoing for a CO_2 pipeline joining Indiana with Enhanced Oil Recovery (EOR) opportunities in the southwest, estimated to be 3 or 4 years away. These two opportunities could help satisfy future CO_2 emission requirements, especially for a "first plant" that could negotiate long term out take contracts, particularly if combined with the blending of bio-mass with coal feedstock to further reduce carbon footprint.

1.11 Recommendations Energy experts such as the DOE Energy Information Agency (EIA) predict that the percentage of energy supplied by coal will actually increase over the next twenty years. It seems prudent to continue to plan, to develop advanced clean coal technology, and to be well positioned as a State to react as solutions develop and market conditions dictate.

We specifically recommend the State of Indiana continue to aggressively motivate and incentivize the pursuit of clean coal technologies. Indiana has the natural resources readily available, the land required, the utilities necessary, and the drive to advance its technological aptitude in order to compete in today's rapidly evolving market. It is recommended that additional planning be done to accomplish the following:

- Develop a State-wide coal to alternative products strategy (liquid fuels, synthetic natural gas (SNG), fertilizer, chemicals, electric power), including policy options and initiatives
- Position Indiana as a lead player in the effort to implement solutions to CO_2 management, with special attention to product resale options, new technologies, and enhanced oil recovery via pipeline and sequestration
- Determine the feasibility of coal/bio-mass feedstock mix for clean coal applications.
- Evaluate optimum locations state-wide, including Army National Guard sites.

2.0 Final Report

2.1 Overview This report documents a Feasibility Study performed by SAIC under a grant provided by the Center for Coal Technology Research (CCTR) on December 24, 2007, and jointly funded by SAIC. This Feasibility study is part of an overall CCTR strategy, the intent of which is to advance the viability of coal-based energy technology in the State of Indiana. The Study provides a conceptual definition of a clean coal, environmentally responsible, energy facility that could be located in Southwestern Indiana, designed to maximize satisfaction of State and CCTR energy goals, and provide Naval Support Activity (NSA) Crane with independence from the national electrical grid during an emergency. In addition to electrical power, the plant concept would produce Coal To Liquid (CTL) transportation fuel using the Fischer-Tropsch (F-T) process. Our selected reference design is based on technology currently in use worldwide; although the F-T process has not been demonstrated at commercial scale in the United States. The facility concept would incorporate both commercial scale outputs and, in accordance with CCTR goals, the capability to do relevant coal-based commercial scale Energy Research and Development (R&D). The design concept would leverage existing coal gasification technology, generate a clean Synthesis Gas (Syngas) for power generation and the CTL process, and include the capability to capture CO_2. A baseline concept was selected and an evaluation carried out to provide technical and economic perspective, and represents a major segment of this document. Specific outputs of the study include facility and R&D design concepts; size and product outputs; process analysis; capital and operating cost estimates; a comparative business case analysis; and, analysis relative to the overall feasibility of such a project. An environmental impact analysis was also performed, and will be provided to the State under separate cover. The executive summary of the environmental report has been included as **Annex A** of this report.

This study is the most recent in a series of detailed investigations sponsored by CCTR of prospects for the development of an array of clean coal-based products and projects in Indiana, with the overall objectives of economic development and job creation, via intensified use of one of Indiana's abundant natural resources, and creation of a State leadership role in clean coal technologies.

This Indiana Coal Gasification Feasibility Study entailed an assessment of the potential for gasification of Indiana coal to produce products with high market value, such as liquids for transportation and industrial applications, synthetic natural gas, or fertilizer, as well as serve as a research anchor for Indiana's clean coal strategy.

2.1.1 The Time is Now – The Place is Indiana With the rapid run-up in oil prices, development of an environmentally sound energy security policy has become an increasingly critical national priority. It is obvious to most that no silver bullet exists and that all possible national resources must play a part in the ultimate strategy (from conservation, to renewable, to nuclear and coal).

The State has developed a focused energy strategy to leverage its biomass and mineral assets. Under this strategy, the State has invested in identifying and developing commercially viable opportunities to grow a state-based energy industry. Of particular relevance for this project, the State CCTR has sponsored a series of studies examining various clean coal technologies that might be commercially viable. Moreover, CCTR analyses also show Southwest-IN with strong CO_2 sequestration potential. In collaboration with neighboring states, Indiana is clearly on the path to expand use of coal in ways that meet or exceed environmental standards.

Department of Defense (DoD) interests have been a major concern in the evolution of this study. DoD's priority for energy security on military bases led to a design criteria that adequate net electricity export be available to support total NSA Crane demand in an emergency. Subsequent to the launch of this project the Defense Science Board issued a recommendation that energy independence be important criteria in future Base Realignments and Closings (BRACs)[2]. Further, DoD has expressed strong interest in synthetic liquid fuels. The Air Force is especially interested in synthetic JP-8. The coal to liquids solutions selected for this feasibility analysis can explicitly address both base energy security and synthetic liquid fuel objectives.

2.1.2 State Planning Objectives The State of Indiana, through the Center for Coal Technology Research and The Office of Energy and Defense Affairs articulated a clear set of planning objectives by which to guide this analysis. The primary objectives articulated by the State are:

- Create a focused approach to enhance economically viable "clean coal" opportunities for Indiana
  - Commercial viability
  - Enable growth in Indiana energy industry
  - Increase the use of Indiana coal
  - If commercially viable, design-in a capacity to blend biomass into coal gasification
  - Product mix tailored to regional demand requirements
  - Design that could be scaled and modified to other locations and conditions
  - Design to meet or exceed environmental standards
  - Design-in CO_2 capture to prepare for potential sequestration and maximize commercial CO_2 use
- Achieve "Crane energy independence" – defined herein as potential grid independence -- and enhance Crane's value to DoD
  - Provide adequate continuous electric power to support Crane in an emergency
  - And/or develop the potential to supply Crane's natural gas requirements with Synthetic Natural Gas (SNG)
  - Locate on or near the Crane facility in order to enhance "physical security"
  - Concept designed to encourage DoD/Department of Energy (DOE) support as a pilot for potential replication in other locations to meet DoD energy independence goals for its base network with small scale coal gasification facilities that provide
    - distributed electric power and F-T liquids
    - or distributed electric power and SNG
- Develop a design concept for a commercially viable coal-fired facility that incorporates space, and fixtures that can serve as an R&D test bed and a hub for an Indiana Energy R&D center

[2] (*Report of the Defense Science Board Task Force on DoD Energy Strategy, More Fight – Less Fuel*, February 2008.

2.2 Approach

2.2.1 Process and Evaluation SAIC approached this study by defining criteria based on Indiana goals for a reference design facility concept that could then be evaluated for technical and economic feasibility. We concluded that a product/product mix needed to be determined early as such decisions drive facility design, process, and cost. The facility design criteria used in this study are as follows:

- Generate 25 Megawatts (MW) of continuous power to the local grid, sufficient to supply NSA Crane peak load, independent of the national grid
- Locate on or near NSA Crane to enhance Crane's value through future BRACs, and be supportable logistically (e.g. coal and water) at that location
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- Projected capital investment of less that $1 billion

Within the context of our criteria, we performed a "quick look" business case, by modeling available facility size, product, and capital cost data; and by researching local and national product markets; and discussing product sales with potential credible customers.

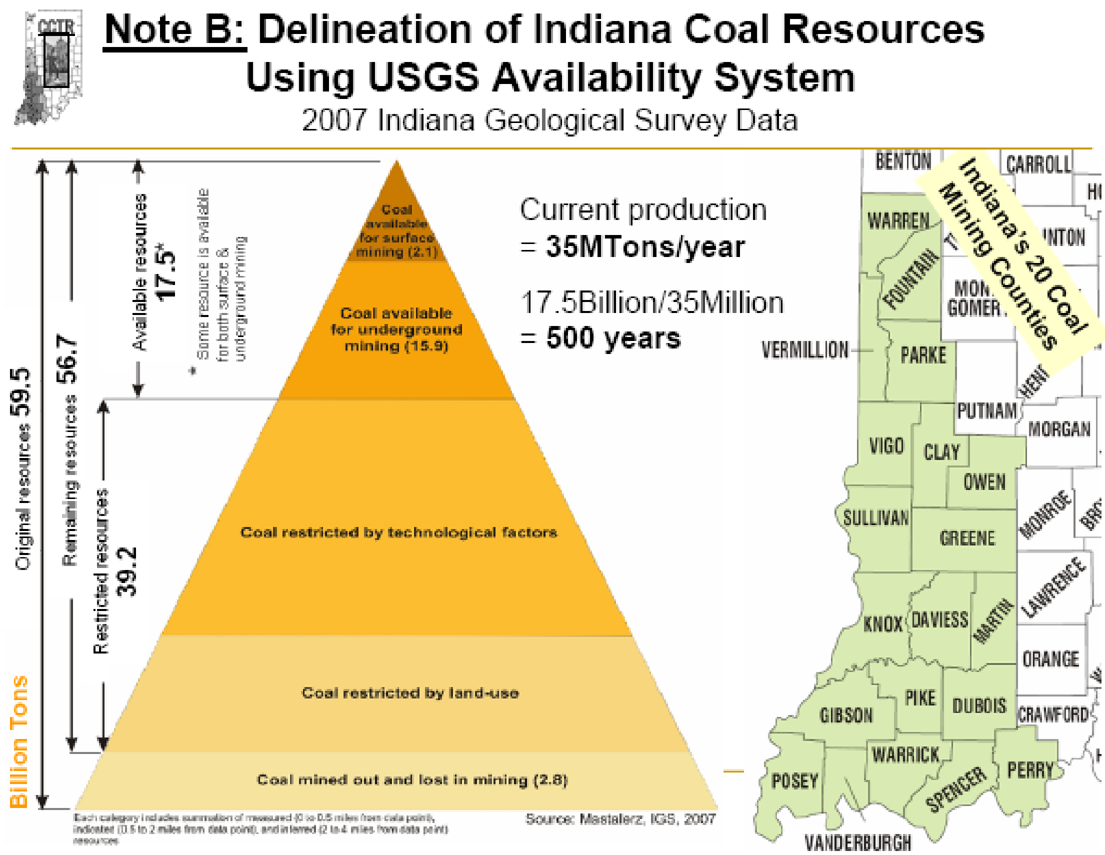
We further characterized the types of R&D capability of primary interest to academia and industry. We were then able to develop a baseline facility design and business model, and perform a feasibility level economic and technical analysis around the baseline design.

The study assessed a range of product and production options that could be built around a coal gasification facility that met the maximum number of State goals. The scope of the feasibility study evolved from consideration of a small Integrated Gasification Combined-Cycle (IGCC) that would meet Crane's energy needs to an examination of a variety of options that would meet the goal while producing a product mix that would be commercially viable and achieve other priorities. From this range of options, three emerged for more detailed investigation: synthetic natural gas, liquid fuels, and fertilizer. All three appeared potentially viable. All met an array of State goals. Of the three, the liquid fuels option presents a new national capability and a new market for Indiana coal; has an available local market; addresses the immediate transportation fuel crisis; takes advantage of the crude oil price run-up; and addresses DoD long-term concerns. In consultation with CCTR, the team settled on liquid fuels as the primary product mix for more detailed analysis.

2.2.2 Coal in Indiana

2.2.2.1 Supply

A key question is "are there coal resources available to support the proposed facility"? The facility is proposed to be located in the heart of Indiana coal country. Two new mines are being opened within 20 miles of the proposed site. The calculated facility coal demand is a small fraction of existing and projected mine capacity in the region. In 2006, Indiana coal production was 34,715,610 tons.[3] Based on 2,000 to 3,000 tons per day, the proposed facility would consume a mere 2-3% of 2006 production. Indiana's coal resources are more than adequate to support multiple facilities of this magnitude as well as proposed future IGCC operations **Figure 2.2.2.1-1**. Expanding demand for Indiana's coal resources is a primary goal of this project.



Source: USGS, reported in Brian H. Bowen and Marty W. Irwin, Indiana Center for Coal Technology Research, "CCTR & Indiana's Clean Coal Initiative," a presentation to the ASME Central Indiana Section, Jan. 16, 2008, p. 5.

Figure 2.2.2.1-1: Indiana Coal Resources

[3] Indiana Coal Council, *2006 Indiana Coal Production*, http://www.indianacoal.com/.

2.2.2.2 Quality The American Society for Testing and Materials ranks all coal produced in Indiana as a high-volatile bituminous coal. "Coal is a heterogeneous rock and has considerable variation in chemical and physical properties within a particular seam and also between seams. Indiana coal has a natural moisture content of about 5 to 15 percent; heating value of 10,500 to 12,000 Btu; per pound ash content of about 5 to 20 percent; and sulfur content of about 0.5 to 6 percent."[4]

These coals are quite suitable for gasification. Preliminary analysis "…demonstrates that Indiana coals are generally good feedstock for IGCC, although variations in properties exist both between the coal beds and within coal beds…"[5] Indiana coals have slightly higher than preferred moisture content. Those coals with higher sulfur content are actually preferred due to the value of the extracted high quality sulfur. The relatively low mercury and chlorine content of Indiana coal also improves its value as a feedstock.

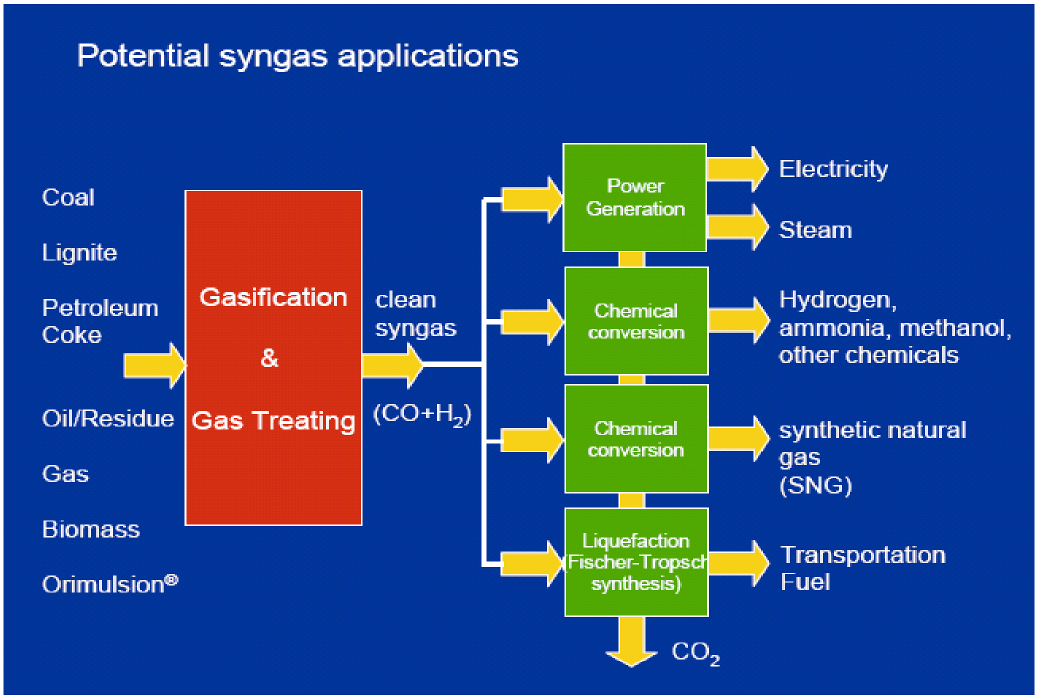
2.2.3 Initial Design and Scaling Considerations

2.2.3.1 Small Commercial Electric Power Unit (25MW) In light of the strong desire to help Crane achieve grid independence and increase its value to DoD, a stand-alone small (25MW) coal Syngas fed power facility was the first option evaluated. At this scale, a quick review verified that the economics could not be justified. A much larger scale project, such as the recently approved Duke Energy Edwardsport IGCC power facility (630 MW), is required to achieve economic efficiency as a stand-alone power generation facility. For smaller scale facilities, commercial viability requires the coal Syngas to have alternative high value uses / products, with salable electricity produced as a secondary, but critical product. Coal gasification offers one of the most versatile and clean ways to convert coal into electricity, hydrogen, transportation fuels, and other valuable energy products.

2.2.3.2 Polygeneration Gasification is a term that describes a chemical process by which carbonaceous (hydrocarbon) materials (coal, petroleum coke, biomass, etc.) are converted to a Syngas by means of partial oxidation with air, oxygen, and/or steam.

Once gasified, coal can be processed into many potentially valuable product streams. **Figure 2.2.3.2-1** provides a summary of some high value polygeneration options for coal gasification. Due to this wide range of potential uses, the team evaluated the viability of a highly flexible design where product mix could be altered as requirements and conditions changed.

[4] Indiana Coal Council, *Coal in Indiana*, no date, 5 pgs,
[5] *Indiana Coal Report 2006*, p.48



Source: Ross Rava, Shell Global Solutions (US) Inc., Coal-Gen, Milwaukee, WI, August 1-3, 2007.

Figure 2.2.3.2-1: Polygeneration Potential of Gasification

The team found the potential cost implications of a polygeneration facility that could be readily shifted among multiple product options to be extraordinarily high, because each product mix would require a specific process and equipment.[6] Optimal process designs for alternative product mixes required quite different gasifiers, coal feed systems, Syngas pressures, heat, power, and water balances, and many other facility characteristics. Efforts to meet many objectives simultaneously not only raised costs dramatically, but also resulted in a facility that was not efficient for any of the options. Decisions concerning product mix will drive the selection of facility equipment and processes. We optimized for two products-- an electric power minimum and a primary high value liquid fuel product.

2.2.3.3 Facility Design -- Selecting a starting Point Selecting a minimum potential commercial size for the reference design was accomplished by including as many of the State planning goals as possible into an SAIC model developed based on DOE / National Energy Technology Laboratory (NETL) studies on coal gasification and F-T liquids production. **Table 2.2.3.3-1** summarizes some of the facility scale characteristics from these studies that we used for evaluation. As the design concept was iterated, a facility design on the order of 2,000 to 3.000 tons / day was selected for the following reasons:

[6] Crane energy independence was used as a design criterion (25MW continuous electric power to the grid, but immediately available to Crane if needed).

- Smallest commercially viable CTL facility that was scalable
- Capital cost fell in the $1 billion range
- Local demand for F-T liquids
- Continuous net electricity production supported the Crane grid independence goal
- Minimizes the CO_2 output to enable potential solutions short of full-blown geologic sequestration
- Compatible with resource and infrastructure availability for alternative sites across Indiana, including on or near Crane

The table contains generalized estimates based on reviewing multiple studies that reflect different product distributions for power and fuel, and designs for carbon management.

Table 2.2.3.3-1: Plant Scaling Analysis

Coal, tons per day	Potential F-T Liquid Output, BPD	Illustrative Capital Cost,* US$ Million	Capital Cost per BPD Output $/BPD
300	500	$200	$400,000
1,200	2,000	$400	$200,000
3,000	5,000	$800	$160,000
6,000	10,000	$1,300	$130,000
20,000	30,000	$3,000	$100,000
30,000	50,000	$4,000	$80,000

Source: SAIC based on NETL data.
Capital cost is mid 2006 dollars and includes CO_2 capture, but not compression and
* storage, or sequestration

For the purposes of this feasibility study, we selected a minimum commercially viable reference design of 2,700 tons of coal per day and producing over 6,000 barrels per day (bpd) of F-T liquids. Obviously, a larger facility could yield greater economic advantages but would not meet other decision criteria for this feasibility study.

2.3 Technical Results

2.3.1 Reference Design Our selected reference design is based on technology currently in use worldwide; although those related to the F-T process have not been demonstrated at commercial scale in the United States.

A summary of the facility performance follows (**Table 2.3.1-1**):

Table 2.3.1-1: Reference Plant Performance	
Plant Output	**2700 tons coal/day Refined F-T Liquids**
Naphtha, bpd	2,704
Distillate, bpd	3,394
Total hydrocarbon product, bpd	6099
Gross power, MW	71.8
Net power, MW	25.1
Carbon dioxide, tons/day	3362
Sulfur, tons/day	78.2
Slag, tons/day	267.9

2.3.1.1 Process Flow Diagram The facility configuration selected for this study is based on the recent *Technical and Economic Assessment of Small-Scale Fischer-Tropsch Liquids Facilities* published by the National Energy Technology Laboratory, February 27, 2007.[7] This analysis was carried out by NETL, SAIC, Parsons, and Nexant. The process flow diagram in **Figure 2.3.1.1-1** shows the facility configuration with product hydrotreating and hydrogen recovery.

[7] Technical And Economic Assessment of Small-Scale Fischer-Tropsch Liquids Facilities, L. Van Bibber, E. Shuster, J. Haslbeck, M. Rutkowski, S. Olson, S. Kramer, DOE/NETL-2007/1253, February 27, 2007

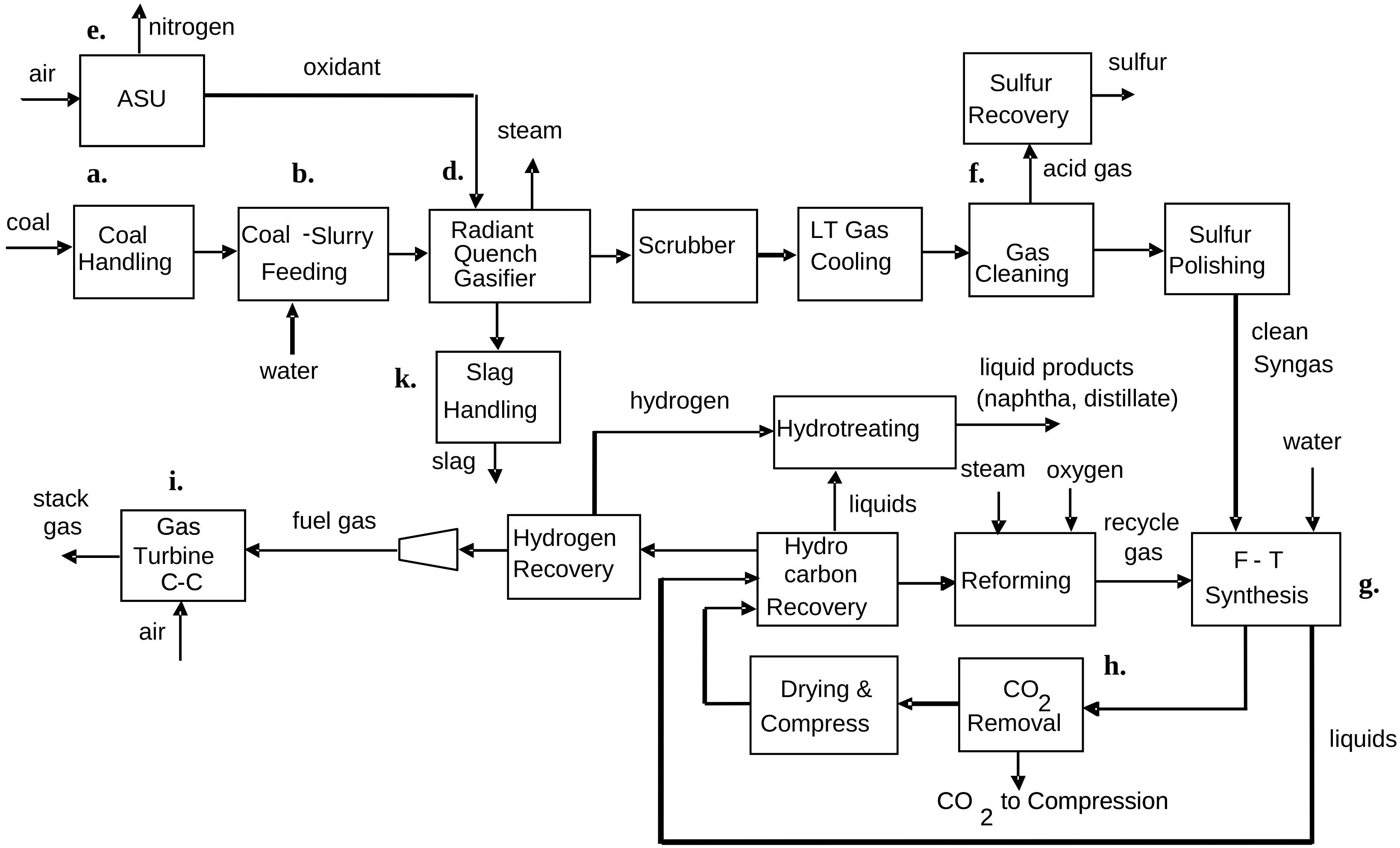


Figure 2.3.1.1-1: F-T Refined Liquids Plant with Carbon Capture (90%)[8]

[8] Several specific technologies are referred to in this flow diagram. Others are implicit in the reference design and are called out in the capital cost calculations below. Identification of specific technologies and equipment were required to generate capital cost estimates with as many "known" quantities as possible. The final design may and in fact probably will use quite different technologies and equipment

2.3.1.2 Facility Design A summary of the major equipment included in the facility design follows:

a. Coal receiving and handling: Coal is received by rail in 100 ton hoppers, with conveyors, crushers, and storage bins. The site has been configured to handle a 60 day supply. Control of storm water runoff is an important environmental consideration.

b. Fuel slurry preparation and fuel injection: Feeders, conveyors, hoppers, rod mill, slurry pumps, storage tanks. Although this portion of the process is a common design, the unscheduled interruption of flow to the gasification units would cause a system shut down and considerable expense if for a prolonged period. Planning for redundant pumping capacity is an important consideration.

c. Condensate and feedwater system: Storage tanks, feedwater pumps deaerator, liquid waste treatment, makeup demineralizer, cooling water pumps, instrument air dryers, air compressors. The entire process must include an evaluation of equipment failure impact for each step with redundant capacity included where risk to the Syngas/F-T process continuity is marginalized.

d. Gasification: A minimum of two pressurized slurry-feed entrained bed gasifiers, Syngas cooler, Syngas scrubber, flare stack. While each reference facility capacity could be achieved with a single gasifier train, two gasifier trains are assumed to provide increased facility availability and running at less than full capacity extends the periods between scheduled shutdowns for maintenance. Shutting down one of the gasifiers for maintenance would allow the F-T process to continue.

e. Air Separation Unit (ASU): Conventional cryogenic Air Separation Unit. This unit provides the oxygen to the gasification process and is a key and expensive part of the process. Site planning must consider future expansion of the ASU to provide for an increase in number of gasifiers and number of F-T product trains.

f. Syngas cleanup: COS hydrolysis reactors, sulfated carbon bed for mercury removal, acid gas absorber, acid gas stripper, pumps, exchangers, Claus sulfur facility. For the F-T process this is one of the most critical portions of the process as particulate removal and sulfur removal are key requirements for a successful F-T process.

g. Fischer-Tropsch process: Sulfur polisher, F-T synthesis reactors, carbon dioxide removal using amine, fractionator, Pressure Swing Absorption (PSA) hydrogen recovery (for refined product option), hydrotreating reactors (for refined product option). The maintenance of the catalyst is a critical step in the reliability and cost of the F-T licensing arrangement. The facility configuration uses hydrogen capture and hydrotreating to produce more refined liquid products.

h. Carbon dioxide capture: The facility concept includes carbon dioxide capture from the F-T synthesis effluent. Carbon dioxide is not captured from the gas turbine exhaust. The facility design uses an amine system following the F-T synthesis that produces CO_2 at nominal 250 psia pressure for commercial or industrial use.

i. Power generation: Combustion turbine and auxiliaries, waste heat boiler, ducting, steam turbine, condenser, stack. The steam turbine is used to make power using the waste heat from the gasification, Syngas quenching process, and the Syngas combustion turbine. The Syngas combustion turbine provides about 30% of the total facility gross power and the steam turbine provides the balance. Between the two power sources 25 MW of constant net power is exported to the grid. Environmental control equipment for the combustion turbine is selected to meet all Best Available Control Technology (BACT) guidelines.

j. Cooling water system: Circulating water pumps, cooling tower. The site might support the space required for a lagoon as an alternative for cooling process water. The facility design includes an evaporative cooling tower and all process blowdown streams are treated and recycled to the cooling tower.

k. Slag recovery and handling: Slag quench, crusher, separation, storage, pumps. The slag is suitable for resale as an aggregate for highway construction and other purposes.

2.3.1.3 Fuel Characteristics The coal composition selected for this study is Indiana mined coal, Illinois Basin #6, shown in **Table 2.3.1.3-1**. For the F-T process the consistency of feedstock is very important due to extensive controls on Syngas consistency and planning for the Syngas cleanup phase.

Table 2.3.1.3-1: Coal Composition

Weight % / Comp	As Received weight %	Dry weight %
Moisture	6.0	0
Ash	9.9	10.6
Volatile Matter	35.9	38.2
Fixed Carbon	48.2	51.2
HHV, Btu/lb	12,450	13,244
Carbon	69.36	73.79
Hydrogen	5.18	4.81
Nitrogen	1.22	1.29
Sulfur	2.89	3.07
Oxygen	11.41	6.47

2.3.1.4 Mass and Heat Balances

Mass and heat balances have been developed based on the referenced NETL study using an internal SAIC model in conformance with accepted industry standards.

The process block flow diagram identifying selected process streams is shown in **Figure 2.3.1.4-1.**

Using this block flow diagram, heat and mass balances are presented for the 2,700 tons of coal feed per day design in **Table 2.3.1.4-2**.

Annex B provides an overview of the major process steps for producing hydrocarbon liquids from coal, as well as a discussion of some of the major trade-offs among competing F-T technologies and approaches.

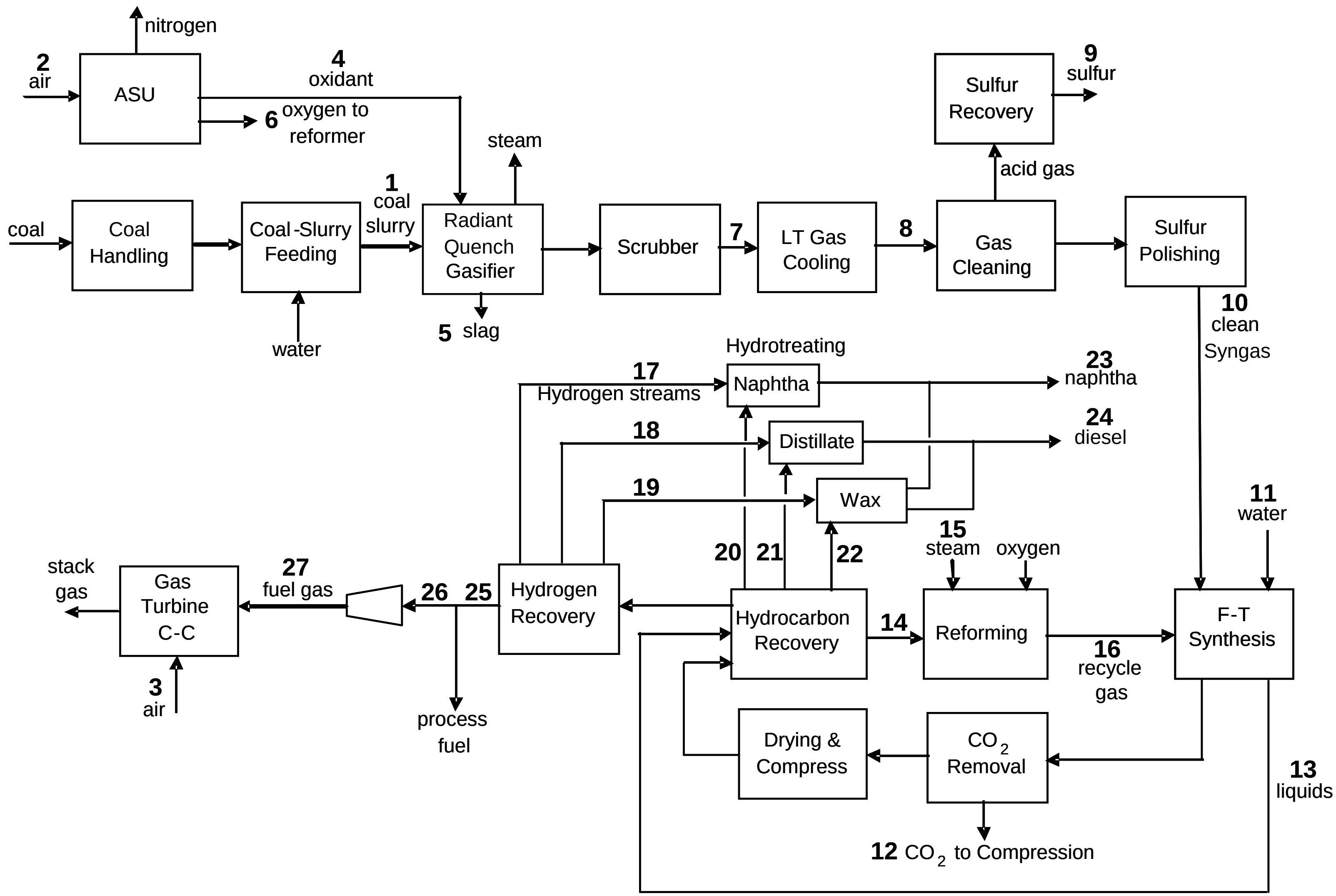


Figure 2.3.1.4-1: F-T Refined Liquids Plant with Partial Carbon Capture

Table 2.3.1.4-2: M&E BALANCES FOR 2700 TPD COAL-TO-REFINED F-T LIQUIDS PLANT

Basis		**Coal**		**Plant Output**		**Auxiliary Load (kW)**	
Site ambient conditions	ISO	Representative of Ill. #6 Coal		Gas turbine power (kW)	21,790	Coal handling	38
As-received coal rate (TPD)	2700	As-received moisture (wt%)	6	Steam turbine power (kW)	44,811	Coal milling	1,047
Plant products	FT naphtha	Ultimate Analysis (dry wt%)		Syngas expander power (kW)	5,203	Coal slurry pumps	254
	FT Diesel	carbon	73.79	Total (kW)	71,803	Slag handling and dewatering	540
		hydrogen	4.81	Auxiliary power (kW)	51,369	ASU air compressor	29,111
		nitrogen	1.29	Net plant power (kW)	20,434	Oxygen compressor	5,671
		sulfur	3.07	F-T production (refined) (bbl/day)	6,099	Fuel gas compressor	2,110
		ash	10.57	CO2 removal (% coal C)	48.97	All FT processes	2,647
		oxygen	6.47	Water consumption (bbl per bbl FT liquids)	15.3	Boiler feedwater pumps	555
		HHV (Btu/lb as received)	12,450			Condensate pump	11
				Net power w/o CO2 compression (kW)	25,089	Flash bottoms pump	127
						Circulating water pump	819
						Cooling tower fans	184
						Scrubber pumps	129
						Selexol plant auxiliaries	1,254
						Claus plant auxiliaries	103
						Balance-of-plant	1,904
						CO2 compressor	4655
						Transformer losses	209
						Total	51,369

Stream	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Description	coal slurry	Air	Air	Oxygen	Slag	Oxygen	Syngas	Syngas	Sulfur	Syngas	Water	CO2	F-T liquids
V-L flowrate (lbmol/hr)	5,893	26,710	20,702	6,354	0	106	22,728	21,155		19,917	331	6,368	70
V-L flowrate (lb/hr)	105,930	770,319	597,349	204,469	0	3,372	469,622	440,644		395,016	5,971	280,249	37,951
Solids flowrate (lb/hr)	211,500	0	0	0	23,777	0	0	0	6,480	0	0	0	0
Temperature (F)	60	59	59	207	300	90	322	102	355	112	240	100	488
Pressure (psia)	1050	14	14	1025	798	375	798	720	25	719	325	265	304
Stream Density (lb/ft3)		0.075	0.075	4.606		2.062	1.966	2.487		2.324	56.237	2.138	42.391
Liquid Vol @ 60F (ft3/hr)													
Molecular weight		28.85	28.85	32.18		31.8	20.66	20.83		19.83	18.02	44.01	537.66
V-L mole fractions													
Ar		0.0094	0.0094	0.032			0.0089	0.0096		0.01			
CH4							0.0006	0.0007		0.0007			0.001
CO							0.43	0.4604		0.4799			0.0012
CO2		0.0003	0.0003				0.1314	0.1415		0.1115		1.00	0.0507
COS							0.0003	0		0			0
H2							0.3433	0.3688		0.3871			0.0077
H2O	1.00	0.0104	0.0104				0.0673	0.0013		0.0009	1.00		0.0562
H2S							0.0083	0.0083		0			0
N2		0.7722	0.7722	0.018		0.05	0.0088	0.0094		0.0099			0.0058
NH3							0.001	0.0002		0			0
O2		0.2077	0.2077	0.95		0.95							
C2H4													0.0005
C2H6													0.0001
C3H6													0.0007
C3H8													0.0001
IC4H8													4E-05
NC4H8													0.0008
IC4H10													1E-05
NC4H10													0.0002
C5H10													0.0009
NC5H12													0.0003
IC5H12													3E-05
C6H12													0.0012
NC6H14													0.0004
IC6H14													4E-05
C7H14													0.0014
C7H16													0.0007
C8H16													0.0017
C8H18													0.0008
C9H18													0.0021
C9H20													0.0009
C10-C20 Olefins													0.0592
C10-C20 Paraffins													0.0263
C7-300HC													0
3-350HC													
350-500HC													
500+HC													
C7-300HT													
3-350HT													0
350-500HT													0
500+HT													0
OXYVAP													0.0002
OXHC													0.0023
OXH2O													0.0007
C21-C29 Paraffin/Olefin Mix													0.1617
C30+Waxes													0.6139
Total	1.00	1.00	1.00	1.00	0.00	1.00	1.00	1.00	0.00	1.00	1.00	1.00	1.00

Stream	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**
Description	Recycle	Steam	Recycle	Hydrogen	Hydrogen	Hydrogen	Raw Naphtha	Raw Distillate	Wax	Naphtha	Diesil Dist	FG	FG	FG
V-L flowrate (lbmol/hr)	3,454	779	4,579	160	79	415	132	72	63	401	268	1,374	1,102	1,102
V-L flowrate (lb/hr)	43,065	14,035	60,472	322	159	837	13,741	12,794	39,334	42,663	60,589	28,122	22,560	22,560
Solids flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (F)	1706	650	1780	100	100	100	100	100	100	128	236	90	90	385
Pressure (psia)	375	615	355	600	600	120	50	50	50	40	20	20	20	460
Stream Density (lb/ft3)	0.2	1.022	0.194	0.197	0.197	0.04	43.055	46.129	51.397	41	44	0.067	0.067	1
Liquid Vol @ 60F (ft3/hr)							309.134	264.7033	754.802	633	794			
Molecular weight	12.47	18.02	13.2	2.02	2.02	2.02	104.3	176.49	617.86	107	226	19.86	19.86	19.86
V-L mole fractions														
Ar												0	0	0
CH4	0.0353		0.0072									0.045342	0.045342	0.045342
CO	0.0617		0.07639									0.072891	0.072891	0.072891
CO2	0.0039		0.01465									0.00729	0.00729	0.00729
COS	0		0									0	0	0
H2	0.585		0.51348	1.00	1.00	1.00						0.389448	0.389448	0.389448
H2O	0	1.00	0.16085									0.001037	0.001037	0.001037
H2S			0.000137									0	0	0
N2	0.2998		0.22729									0.354404	0.354404	0.354404
NH3	0		0									0	0	0
O2												0	0	0
C2H4	0.0107											0.012702	0.012702	0.012702
C2H6	0.0025											0.008913	0.008913	0.008913
C3H6	0.0008											0.033052	0.033052	0.033052
C3H8	0.0001											0.020058	0.020058	0.020058
IC4H8	0											0.001362	0.001362	0.001362
NC4H8	5E-05											0.02588	0.02588	0.02588
IC4H10	0											0.010571	0.010571	0.010571
NC4H10	1E-05											0.016612	0.016612	0.016612
C5H10	0						0.00057			0.11447		0.000022	0.000022	0.000022
NC5H12							0.04255			0.0835		0.000007	0.000007	0.000007
IC5H12							0			0.0564		0.000001	0.000001	0.000001
C6H12							0.18391			0		0.000018	0.000018	0.000018
NC6H14							0.05517			0.15687		0.000006	0.000006	0.000006
IC6H14							0.00613			0.08191		0	0	0
C7H14							0.14229			0		0.000015	0.000015	0.000015
C7H16							0.06098					0.000007	0.000007	0.000007
C8H16							0.11807					0.000013	0.000013	0.000013
C8H18							0.0506					0.000006	0.000006	0.000006
C9H18							0.09795					0.000012	0.000012	0.000012
C9H20							0.04198					0.000005	0.000005	0.000005
C10-C20 Olefins							0.08126	0.584636	0.0259			0.000047	0.000047	0.000047
C10-C20 Paraffins							0.03482	0.250559	0.0111			0.00002	0.00002	0.00002
C7-300HC							0	0	0	0.17351		0	0	0
3-350HC							0	0	0	0.04572		0	0	0
350-500HC							0	0	0	0	0.264	0	0	0
500+HC							0	0	0	0	0.386	0	0	0
C7-300HT							0	0	0	0.23327	0	0	0	0
3-350HT							0	0	0	0.05436	0	0	0	0
350-500HT							0	0	0	0	0.241	0	0	0
500+HT							0	0	0	0	0.109	0	0	0
OXYVAP							0	0	0	0	0	0.000004	0.000004	0.000004
OXHC							0.08371	0.164805	0	0	0	0.00002	0.00002	0.00002
OXH2O							0	0	0	0	0	0.000014	0.000014	0.000014
C21-C29 Paraffin/Olefin Mix							0	0	0.27264	0	0	0.000005	0.000005	0.000005
C30+Waxes							0	0	0.69036	0	0	0	0	0
Total	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

2.3.2 Site Selection and Crane Linkages As a result of the desire for grid independence for Crane and the interest in physical security of the concept site in the event of emergency, location options on or near Crane were assessed. Initially, a site on-base was the preferred location, assuming land could be made available through the Navy's Enhanced Lease process. However, the approval process for an on-base lease is time consuming and the Navy environmental permitting process quite complex. Ownership and use restrictions had the potential to impair the needed commercial viability for the project. Water availability and coal supply logistics were also easier and less expensive off-base. Therefore an off-base option became the preferred location.

The off-base option entailed reviewing land contiguous with the Crane border. This land is considered to be of limited agricultural use and therefore classified as relatively low value land. For the purpose of this study, a site was identified adjoining Crane which with appropriate preparation, could be incorporated into Crane's perimeter protection if needed. By adjoining Crane, water from the Crane waste water treatment facility is available to meet part of the facility's process water requirements.[9] Plus, the site has good rail and road access, and is close to high tension power lines, coal mines, natural gas pipelines, and potential CO_2 sequestration geology.

The **Figure 2.3.2-1** site plan was developed to give a sense of the relative size in acres that the facility would require. The concept site could be moved anywhere within a reasonable distance from NSA Crane. The resulting layout covers about 130 acres adjacent to an existing active railroad, near a state highway and the NSA Crane boundary. This allowed the site to be given an environmental evaluation using available information on wet lands and other physical features. It also allowed the site engineers to layout the railroad siding configuration shown. Roughly two thirds of the site will be feedstock storage and a handling area due to the requirement for a 60 day supply of coal and future storage for a 25% biomass storage area. This layout would allow a staging area for a full train of coal cars to be delivered and unloaded about every two weeks. At the top of the site plan the actual gasification to F-T fuel process is laid out in typical linear fashion. Additional space has been allocated around each of the primary component "Islands" to allow temporary insertion of semi-truck bed sized R&D components used to pull slipstreams of Syngas, cleaned Syngas, hydrogen, and CO_2 for test and equipment validation purposes.

[9] Depending upon the design chosen, Crane's wastewater volume might meet all requirements. It could meet a large share of the water requirement of any of the designs under consideration. Detailed planning will assess the economics of the use of Crane wastewater as part of the final design.

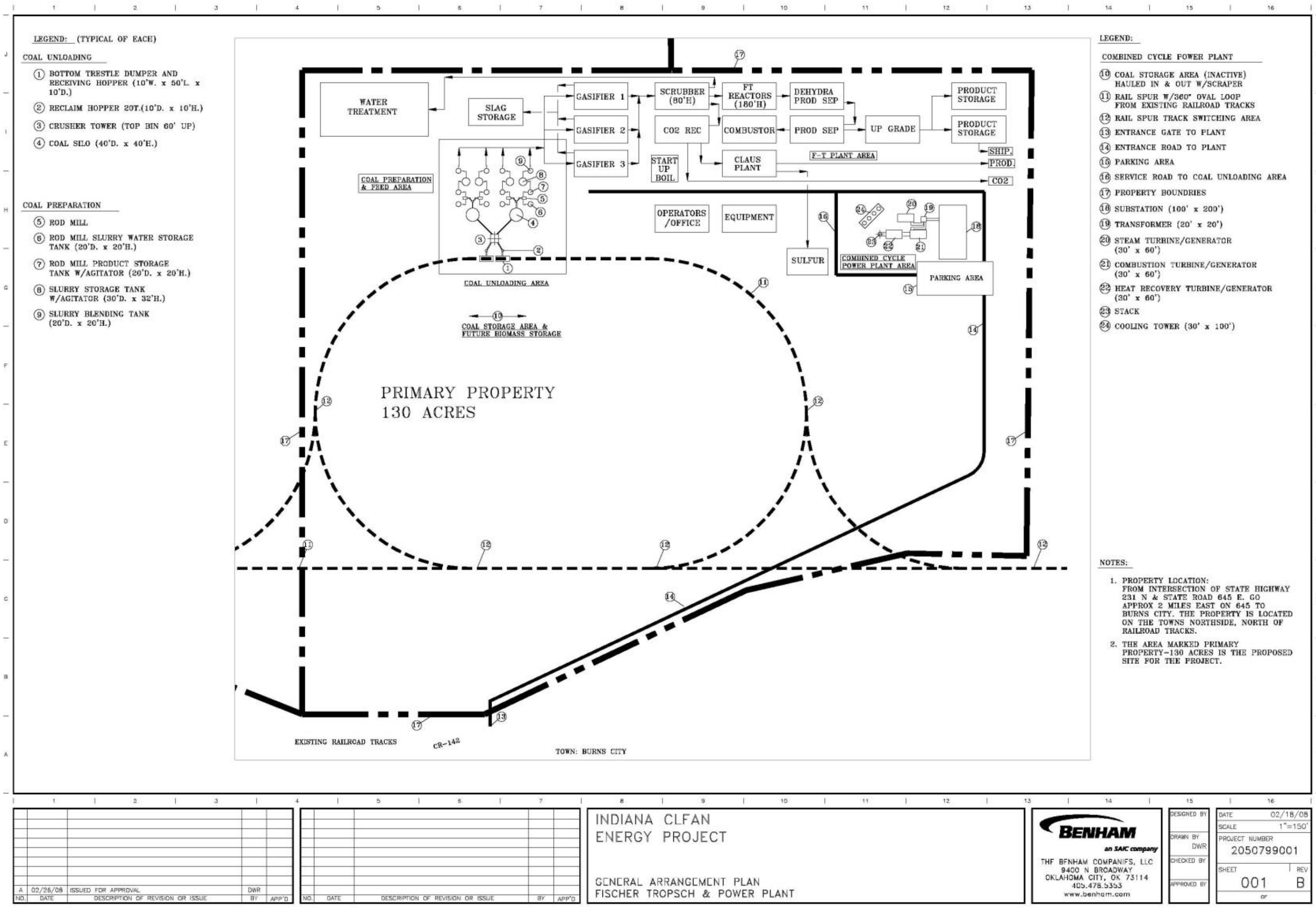


Figure 2.3.2-1: Conceptual Site Layout

Looking beyond this feasibility study toward detailed site and engineering planning, commercial considerations such as logistics and material handling may shift the optimal site away from this Crane-border location, though still nearby. The distances under consideration are modest, and the ability to meet the Crane grid independence goal relatively unaffected. Physical vulnerability may increase modestly. This assumes a "dedicated" power line could be run across public lands, and that it would not be a specific terrorist target. Further, we assume that if disrupted the line could be repaired with routine company lineman assets. Land costs may rise significantly, but land costs are a small part of total capital cost, and thus not a driver. If the Navy determines that a location on NSA Crane becomes more attractive, this option will, of course, be revisited.[10]

2.3.3 Research and Development Platform A key State objective is to make Indiana an Energy R&D Center with clean coal initiatives central to that vision. If a project were to include flexibility for inserting equipment/technology to allow commercial scale testing, the plant layout, major equipment spacing, and piping systems will need to be designed to accommodate a variety of placements without hindering the daily operation and efficiency of the commercial product line would be required from the research community so that scope of plant interfaces, additional auxiliary equipment, and potential environmental considerations could be defined. The additional design cost and capital investment would not provide a commercial ROI, and may require State, Academic and industrial funding. Although an R&D platform would benefit the State and Industry, the operating plant must also be commercially viable.

2.3.3.1 Potential R&D Facility Features The following are areas of R&D which could be considered as part of any research platform:

- Scalable facility with each island sized and plumbed to permit R&D interfaces
  - Alternative materials storage, processing, and handling technologies (coal and biomass)
  - Space and "port" for an additional gasifier
  - Syngas slipstream (raw and clean) for product & process testing
  - Potential hydrogen slipstream
  - F-T liquid distillate slipstreams (raw distillate and refined distillate)
  - Grid and grid interface access for grid management and stability testing
  - CO_2 slipstream for testing alternative sequestration technologies and systems
- Extensive sensor and data capture systems for research, simulation, and training (on-site and remote)
- Labs and meeting/class room space for training and short/long term university and industry R&D teams

Input is being sought from the research community on the highest value R&D elements, as well as low-cost ways to lay out the facility to accommodate future investments in R&D.

Materials handling: Materials handling is very space intensive. Coal storage and handling represents by far the largest component of the facility's footprint. To the extent that experimentation with alternative gasifiers and biomass blending are key research goals, then

[10] Depending upon the continuous power export capacity of the final design and the switching capability of the local grid, this facility may have additional homeland security and economic value. With sufficient capacity, a zone around Crane could offer hospitals, emergency response facilities, and potentially even some industrial sites a degree of energy independence.

enough physical space and any supporting infrastructure must be integral to the design to support not only transport and storage alternatives, but a variety of raw materials handling and processing trains.

Additional gasifier port: At a minimum, the space and supporting infrastructure for a third gasifier port is required to support any future growth. Further, if biomass is used as a feedstock, with current technology, a separate gasifier would be required since blending of biomass and coal into a single gasifier is not a proven approach. On a research basis blending could be an option but the resulting synthetic gas may not be suitable for the F-T process. The third port could be used for an identical gasifier which would match output characteristics of the original two or could be a research port for new gasifier technology. There are many gasifiers currently available on the market, many others are under development, and all will need to be tested either on a prototype or commercial scale. This facility could provide the ability to accommodate such testing in a production environment. As a new energy market emerges, one that utilizes our own natural resources and accommodates environmental regulation, this facility could become a test bed for a variety of new technologies.

Syngas slipstream: As shown in **Figure 2.2.3.-1**, clean Syngas can be transformed into many liquid and chemical products. Much research is being devoted to alternative conversion technologies, gas cleaning processes, and new product development concepts. The ability to pull slipstreams of raw and clean Syngas from the facility processes could provide an economic platform for testing to occur on these new technologies. There is specific interest in supporting focused research on alternative catalysts for the F-T process.

Hydrogen slipstream: With the great interest in commercial hydrogen, techniques for more efficient production from Syngas (above) and the ability to pull hydrogen from the facility to support hydrogen-based experimentation are important. The facility, as preliminarily designed, produces a hydrogen stream to be used in the refining process for F-T liquids. This stream may offer the potential to be tapped for research purposes.

F-T liquids slipstream (raw and refined): The ability to pull distillate for alternate refined fuel experiments and prototype testing is critical to support military interest in F-T liquids. Access to ultra low sulfur diesel and blending of diesel fuel to achieve emerging ultra-clean diesel standards are of significant interest to the military and for commercial diesel engine testing.

Grid and grid interface access: One of the challenges facing the success of emerging distributed energy technologies and systems is the development of efficient and effective technologies to seamlessly integrate multiple electricity sources with highly variable quality and reliability into local, regional, and national power grids. A facility such as the one proposed, producing its own house power plus a minimum of 25MW continuous export power, provides an excellent platform for grid interface and microgrid experimentation. Additionally, a variety of alternate energy projects are under discussion with Crane, such as a large solar farm. The facility could be designed to safely accommodate the management of a variety of experimental power sources, without grid disruption.

CO_2 slipstream: Since control and management of CO_2 has become a major policy issue, providing R&D access to high volume streams of clean CO_2 has emerged as a significant asset. A wide array of research is being devoted to alternative CO_2 control and management technologies and systems, such as F-T synthesis processes that consume more CO_2, accelerated growth greenhouse agriculture, accelerated algae production for alternate approaches to liquid fuels production, and controlled sequestration experiments – to mention only a few. As noted, there is already some potential commercial interest in the captured CO_2. Further, also as noted, the nearby geology has good sequestration potential, and offers some potential for EOR and ECBM. EOR and ECBM are not technologies in common usage in Indiana and eastern Illinois, and will require significant development and testing for the public to feel this is a viable solution. With a ready nearby CO_2 source, such development and testing becomes feasible.

Sensor and data capture systems: Considerable progress has been made in coal gasification and combined cycle Syngas electricity generation. Far less is known about F-T processes. Although an old and proven technology, most advances have been made in private company laboratories overseas, and no commercial scale F-T facilities are located in the United States. The ability to learn from a full scale operation that can be used to optimize not only the processes, but improve the next generation of technology will prove invaluable. For researchers, such data offers the ability to refine modeling and simulation, and perhaps accelerate the commercial availability of advanced technology to the energy market. Moreover, this data offers the ability to support education and training to an unprecedented degree.

Laboratory, meeting and classroom space: A true R&D facility must be able to accommodate, on-site or nearby, long- and short-term teams working on a variety of university and commercial projects, without interfering with the day-to-day facility operations. With coal gasification based technology on the upswing, especially in the coal states, this space could also serve as a common core facility for hands-on training.

2.3.4 Environmental Considerations The CCTR expressed strong interest in an environmentally friendly design. Planning focus was given to meeting or exceeding current State and Federal environmental standards, while positioning to meet potential new requirements. We also performed a environmental impact analysis, to be provided as a separate report, and have included its executive summary as **Annex A** in this report

2.3.4.1 Key Environmental Design Criteria The State expressed strong interest in an environmentally friendly design. Planning focus was given to meeting or exceeding current State and Federal environmental standards, while positioning to meet potential new requirements.

Key environmental considerations included:

- Best practice emissions control
    - Sulfur and mercury removal
    - Heat recovery steam generator equipped for nitrogen oxide control
    - State of the art site design and control technologies used to manage storm water runoff from coal and biomass storage areas
- Maximum sale of byproducts (slag and sulfur, others if economic)
- Sustainable water consumption
- Capture of CO_2 output for
    - Commercial use
    - Potential geologic storage
    - Other technology solutions

2.3.4.2 Environmental Permits The reference design for the proposed CTL facility at the Crane-proximate project site is feasible in terms of current environmental permitting and compliance requirements imposed by Federal and State regulations. A discussion of the detailed environmental analysis that would be required is provided as a separate report. **Annex A** is the executive summary of that report. Indiana Department of Environmental Management's (IDEM) approval of the Edwardsport IGCC facility -- using similar coal gasification-and power subsystem technologies -- provides confidence in our ability to meet State and Federal requirements.[11] The F-T subsystem is a refinery process that would be designed to meet current environmental regulations.

2.3.4.3 Production Emissions The direct environmental impacts associated with CTL are significantly less than those resulting from traditional pulverized coal combustion. Gasification, with Syngas clean-up systems, enables the sulfur and heavy metals (including mercury) in the coal, to be removed, contained, and often processed into marketable products. Even the gasification slag has economic value and will not require landfill or other waste management. More discussion of the markets for waste and byproducts is provided below.

2.3.4.4 Fuel Composition Liquid fuels produced from F-T processing of coal Syngas will be ultra-clean, bio-degradable, and contain very low sulfur. When combusted, F-T diesel and jet fuels will produce very low particulate and NOx emissions, and will have performance characteristics superior to their conventional distillate counterparts (F-T fuels have a much higher cetane rating than standard petroleum middle distillates and burn more efficiently, thus increasing overall engine performance).

2.3.4.5 Water Consumption Uncertainty about water consumption is one of the issues at this stage of the study. Varying design assumptions produce widely differing water balance estimates. Different analyses provide water consumption estimates ranging from 2 to 15 gallons of water per gallon of F-T liquid produced. The reference design will most likely fall in the 4-10 gallon range. Most of the water losses would come from cooling tower evaporation, so discharge is not as great a concern as supply. Design options are available which may reduce water losses due to evaporation, but at substantial capital cost increases. Based on the size of the facility under consideration, water is not expected to be a significant constraint.

2.3.4.6 CO_2 Capture The CTL processes used enables the CO_2 to be captured in a form that can be either used as a commercial product or sequestered rather than being emitted into the atmosphere. Gasification breaks down the feedstock into its basic constituents, thus enabling the economic, high-efficiency separation of regulated pollutants and CO_2. The resulting CO_2 gas stream will be 90 to 99 percent pure, and at a high enough pressure to be suitable for transport via pipeline for commercial application such as EOR or storage.

The reference design will produce some 800,000 to 1.2 million tons of CO_2 per year. Most of that will be captured (about 90% -- losses will occur primarily in the electric generation stack gas emissions). Discussions are currently underway with two potential commercial users considering the purchase of some CO_2 output. Other commercial options are still under consideration, such as EOR. With the restructuring of the DOE FutureGen project there may be an opportunity to seek federal funding for sequestration, perhaps in collaboration with other Indiana facilities.[12] SAIC and the CCTR independently submitted comments to the DOE RFI that incorporated this project as a potential contender in the forthcoming restructured FutureGen

[11] Duke Energy, *News Release*, "Indiana Department of Environmental Management Issues Air Permit for Duke Energy Coal Gasification Power Plant," January 25, 2008; www.duke-energy.com.

[12] United States Department of Energy, Office of Public Affairs, Press Release, "DOE Announces Restructured FutureGen Approach to Demonstrate CCS Technology at Multiple Clean Coal Plants," January 30, 2008.

competition. An analysis performed by the State Utility Forecasting Group determined that the region around Crane ranks well in terms of sequestration geology (see **Table 2.3.4.6-1**).

Table 2.3.4.6-1: Sequestration Potentials of Principal Geological Options located within 25 miles of NSA Crane (Martin County), including potential enhanced recovery volumes of oil and gas from CO_2 injection (MMscf – million standard cubic feet; MMt – million metric tons; EOR – enhanced oil recovery)

Reservoirs	**CO_2 Storage**	**Methane Recovery**	**Enhanced Oil/Gas Recovery**
Saline Reservoirs	**CO_2 Storage Capacity (MMt)**		
Mt. Simon Sandstone	15,355		
St. Peter Sandstone	210		
Total	**15,565**		
Oil & Gas	**CO_2 Storage Capacity (MMt)**		**EOR (standard Barrels)**
Petroleum Fields	0.67		3,828,039
Shale	**CO_2 Storage Capacity (MMt)**	**Shale Gas (MMscf)**	**Enhanced Shale Gas (MMscf)**
New Albany Shale	572	10,004	1,500

Source: State Utility Forecasting Group, Energy Center at Discovery Park, Purdue University, *Synfuel Park / Polygeneration Plant: Feasibility Study for Indiana*, September 30, 2007, Revised January 31, 2008, p. 78.

To summarize this very important issue, the proposed project uses a layered approach to deal with CO_2 emissions. Capture capability is designed into the facility. Initially, all options are being explored to maximize commercial utilization. The CCTR is exploring potential medium-term EOR, Enhanced Shale Recovery (ESR), and ECBM opportunities, both locally and in collaboration with neighboring states (Illinois and potentially Kentucky), as well as the potential for participating in the restructured FutureGen initiative. Longer term, CCTR is exploring how the State might link multiple CO_2 capture sites to the proposed pipeline from Louisiana. A detailed analysis could be performed in the future to address the various aspects of sequestration costs, and how select policy actions and government investment decisions might affect commercial viability. Evolution of a formal carbon capture regime, whether regulatory, tax-based, or cap and trade may have major economic consequences for any project.

2.3.5 Biomass Feedstock The state is very interested in supporting the use of biomass for energy – if it makes economic sense. Indiana is already a home to multiple ethanol and biodiesel plants, with more on the drawing board. A biofuels strategy is enshrined in the State's Energy and Agriculture Plans.[13] There are two primary factors behind an interest in examining a biomass stand alone or biomass-coal blend capability – enhancing the biomass energy market potential and reducing the CO_2 footprint of a CTL strategy.

To be viable, many biomass energy solutions need to focus on smaller scale facilities with less transportation intensive feedstock options. A relatively small scale biomass/coal gasification blending to liquids solution could possibly offer both seasonal and feedstock flexibility that

[13] *Possibilities Unbound: The Plan for 2025* and *Hoosier Homegrown Energy*

would contribute to creating a viable biomass energy market in this region of Indiana – and one that might be transferrable to other coal regions with comparable biomass catchment areas.

2.3.5.1 CO_2 Footprint One of the arguments used in the debate over producing liquid fuels from coal-based Syngas is that the total (lifecycle) CO_2 footprint for CTL is larger than that for petroleum refining.[14] Some sources cite fuels from a standard vented CTL process as having a total CO_2 emissions footprint as much as 80% higher than the same fuels based on petroleum refining.[15] Combining biomass with coal gasification whether in the same gasifier or in separate gasifiers at the same plant offers an important prospect for greatly reducing the CO_2 footprint of CTL. Evidence suggests that a 10 to 30% biomass combined with coal significantly reduces the total CO_2 footprint for a CTL project as compared to producing the same volume of fuels from petroleum refining. See **Annex C** for recent SAIC testimony before the United States Senate Committee on Energy and Natural Resources.

The technical and commercial viability of such combinations of coal and biomass has been demonstrated but there are project specific issues which would have to be considered such as characteristics of the type of biomass, quantity available, desired performance/output, etc. The facility design will accommodate R&D, prototype and even small scale commercial testing, should research suggest potentially viable approaches. Room is designed in for a third gasifier, which could be a biomass gasifier. The location is compatible with receiving, storing and processing a significant biomass volume. At this point, volume information on the array of potential feed-stocks is limited, but even a 10% share would require 270 tons per day on average for our reference facility solution at 2,700 tons of coal per day by volume.

2.3.5.2 Key Biomass Related Facility Design Questions The SAIC team is completing this feasibility analysis without a biomass blending solution, but the blending solution remains an important collateral strategy to be pursued in future analyses.[16] Key questions requiring further investigation include:

- What are the economically available feed stocks in the region?
  - Primary analysis is focused on corn stover, soybean waste, and wood waste.
  - What are the annual and seasonal volumes?
  - Are there biomass waste streams that could be tapped for a stable year round base source of feedstock (agricultural or animal processing, ethanol or biodiesel production, Crane solid waste, etc.)?

- What are the technical/economic blending solutions?
  - Separate gasifiers for coal and biomass with blended Syngas streams
  - Coal – biomass feedstock blend fed into a common gasifier

- How do the likely annual and seasonal volumes impact the facility design's energy and economic balances for different target annual blends (5%, 10%, 20%, etc.) and consequent facility layout and capital equipment purchase decisions?

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[14] Total includes all CO_2 emitted from coal mining through final combustion as a liquid fuel.

[15] Professor Robert Williams, of Princeton University's Princeton Environmental Institute, as reported in National Energy and Technology Laboratory, *Attaining Energy Security in Liquid Fuels Through Diverse U.S. Energy Alternatives*, DOE/NETL-2007/1278, August 1, 2007, pp. 65-66.

[16] Tax incentives and loan guarantees are available to bio-gasification projects, including combined CTL applications under the Energy Policy Act of 2005 that are not available to pure CTL facilities. If authorized funds are appropriated and this project remains eligible, the incentives could significantly improve project economics.

- If biomass seasonality causes significant gasification process challenges, the design would have to reflect storage capacity to assure appropriate input mix year round.
- Similarly, if the biomass input mix is varied enough, the design would have to reflect complex storage, handling and processing facilities.
- Existing commercial gasifiers offer quite different degrees of flexibility as to feedstock composition. Analysis as to the viability of a biomass blend option and the potential mix could significantly impact gasifier design choice and capacity (the greater the volume of biomass the lower the energy density and the higher the capacity required for the same Syngas output).

2.4 Business and Financial Results

2.4.1 Product Markets and Pricing The primary products and byproducts from the reference design include:

Primary products

- Very low-sulfur F-T liquid products

Primary Facility by-product

- Electric power

Secondary Facility by-products

- Syngas
- Sulfur
- Slag
- CO_2

2.4.1.1 F-T Liquids The reference CTL facility will produce some 6,000 bpd of F-T liquids for offsite shipment. The final F-T product stream contains both diesel and naphtha fractions. We anticipate that the diesel portion of the F-T product can be blended directly with petroleum refinery diesel product without further refining. It will contain very low sulfur, low aromatics, and have excellent diesel blending properties. The naphtha portion of the product will require additional refining to process into transportation fuels or could be sold as-is as a chemical raw material, which is in high demand.

F-T Liquids Market Considerations: The market for F-T liquids is expected to be enhanced due to the anticipated low-sulfur specifications for liquid fuels -- especially diesel -- and the anticipated growth of diesel-fueled vehicle use. Moreover, DoD, especially the Air Force is committed to developing a domestic base of alternative sources of JP-8 -- with CTL using F-T at the center of this strategy.[17]

Whatever processing is required would most likely occur with an onsite distillate tower. Distribution of the F-T diesel and naphtha could be accomplished by rail, truck or a new pipeline -- probably the latter for diesel. The pipeline distance to a major refined product distribution node is less than 20 miles.

[17] Although CO_2 is an issue and other alternatives are under investigation, CTL with F-T remains a core strategy. Considerable attention is being given to biomass blending as a partial solution to reducing the CO_2 footprint. Baere Aerospace Consulting, Inc., Trip Report Prepared for the Coal Technology Research Center, USAF Energy Forum II, March 3-4, 2008, Washington DC.

F-T Product Pricing Considerations: Due to the very high quality of F-T diesel to be produced from this facility and the fact that it could be used as a blend to help meet very low sulfur standards, a premium price could be expected when compared to petroleum-based diesel. However, for the purposes of this study, the market price for Gulf Coast Ultra Low Sulfur futures contracts was used. That average quoted price from 2008 to 2011 rounded to $2.89 per gallon.

The generic name naphtha describes a range of different refinery intermediate products used in various applications. Naphtha is used primarily as feedstock for producing a high octane gasoline component (via the catalytic reforming process). It is also used in the petrochemical industry for producing olefins in steam crackers and in the chemical industry for solvent (cleaning) applications. F-T naphtha tends to be an ideal petrochemical feedstock for ethylene and propylene production. The absence of aromatics in this material is expected to yield a 10 percent volume advantage over conventional ethylene and propylene yields. Although the F-T naphtha is expected to be readily marketable as ethylene cracker feedstock future, potentially more economic applications lie within the conventional refinery gasoline blending scheme.[18]

F-T naphtha pricing presented a challenge due to the range of potential commercial applications and the composition variability resulting from differing F-T process technologies. We reviewed three different approaches to create a rule of thumb pricing range for our analysis of $1.92 to $2.44 per gallon.

- First, we used a similar logic to that presented in the 2007 NETL, Alaska Coal Gasification Feasibility Study, which priced F-T naphtha at a $0.10 /gallon discount under spot gasoline prices.[19] We chose to base the analysis on the average price for Gulf Coast Gasoline Futures contracts for 2008 to 2011 rather than spot prices – calculated at $2.54/gallon.[20] Applying the $0.10/gallon discount yields a naphtha price estimate of $2.44/gallon.
- The second approach relies on the estimate used in the 2007 University of Kentucky F-T analysis which valued F-T naphtha at 0.714 the diesel price, based primarily on its comparatively lower octane rating.[21] Applying this factor to the ultra low diesel price assumption above yields an estimated naphtha price of $2.06/gallon.
- A third approach leveraged the modeling analysis prepared for the 2007 NETL report, *Technical and Economic Assessment of Small-Scale Fischer-Tropsch Liquids Facilities*.[22] Detailed modeling analysis was not reported, but the naphtha prices reported averaged about 0.665 of the low sulfur diesel prices used as a proxy for F-T diesel in that same report. Applying that ratio yields a naphtha price estimate of $1.92/gallon. This value was used for our modeling.

Differing F-T processes generate somewhat different product characteristics. To the extent that the alternate F-T technologies are available, and to the extent that a given F-T process can be

[18] Nick Economides, Director, Refining and Reformulated Fuels, Hart Fuels Information Services, Prepared Remarks on the U.S. Environmental Protection Agency's Proposed Heavy Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements, June 27, 2000, Los Angeles, California.

[19] NETL, *Alaska Coal Gasification Feasibility Studies – Healy Coal-To-Liquids Plant*, DOE/NETL-2007/1251, Final Report, July 2007.

[20] Based on close of business results for the 3/24/2008 trading session.

[21] University of Kentucky, Center for Applied Energy Research, *Technologies for Producing Transportation Fuels, Chemicals, Synthetic Natural Gas and Electricity from the Gasification of Kentucky Coal*, July 2007, pp29-30.

[22] *Technical and Economic Assessment of Small-Scale Fischer-Tropsch Liquids Facilities*, DOE/NETL-2007/1253, Final Report for Subtask 41817.401.01.08.003, February 27, 2007, Chapter 5.

modified to alter the mix between diesel and naphtha, there is a market value in choices that maximize the diesel output.

2.4.1.2: Electric Power:

Market Considerations: All variants of CTL facilities produce some surplus electric power as a byproduct. This characteristic is critical for the reference design, since Crane energy independence in an emergency is a key State goal. The amount of exportable power will vary with design choices. For the reference design, 25 MW of continuous net export is a required minimum constraint. Another consideration, is the viability of designing in a generation capacity large enough and flexible enough to be used to meet some peak power needs. Peaking flexibility can be accommodated within limits, but providing for significant electric power peaking capacity imposes design requirements that may be difficult (or rather expensive) to accomplish and still have an optimized F-T process.

Pricing Considerations: Current regional base load power market prices fall in the range of 5 to 7¢/kWh, while peaking power market prices are approximately 20¢/kWh. For calculation purposes, 6¢/kWh was used.

2.4.1.3: Syngas:

Market Considerations: The baseline concept is to use all the Syngas produced for the F-T process to produce liquid fuels except for a minimum 25 MW electric power output to the local grid.

The following discussion is provided to illustrate Syngas product options under different scenarios. Planned gasifier capacity is such that a significant volume of clean Syngas could be produced beyond that required for F-T liquid fuels production. Such Syngas could be used for additional electricity generation or as a substitute heat source for some nearby natural gas intensive consumers (a switch to Syngas from natural gas would require some system modifications by the purchaser).

Depending on cost, design and market conditions, coal-based Syngas could be further processed to produce Synthetic Natural Gas (SNG) or precursors to fertilizer production – both highly attractive and marketable products in Indiana. Either option would involve quite different facility designs and probably not be co-located with an F-T facility.

Some interest has been expressed in providing Crane's natural gas requirements in an emergency with SNG as well as providing the electricity requirements. Again, this would require a different facility than our reference design, but a coal to SNG facility could also be considered. Crane's natural gas consumption in 2006 was 478,694 MBtu, with a winter peak in January of 72,245 MBtu, and a summer trough in August of 16,950 MBtu (**Table 2.4.1.3-1**).

Table 2.4.1.3-1: Crane Natural Gas Usage, FY 2006	
Month	**Natural Gas Usage (Mbtu)**
Oct. 05	21,410
Nov. 05	44,749
Dec. 05	68,195
Jan. 06	72,245
Feb. 06	62,474
Mar. 06	61,786
Apr. 06	40,261
May 06	29,403
Jun. 06	22,198
Jul. 06	19,857
Aug. 06	16,950
Sep. 06	19,857

Source: Crane Public Works

Pricing Considerations: As a rule of thumb the energy content of Syngas is about 25% of natural gas. An assumption was made that the market price per Btu will be identical. The 2008 to 2011 average Henry Hub futures contract price was $9.33/MMbtu, as of close of business on March 25, 2008.

2.4.1.4: Sulfur:

Market Considerations: High quality sulfur is a valuable secondary byproduct of the proposed facility. The F-T process requires very high quality Syngas cleaning. As a result, high sulfur coal could prove to be a superior feedstock. Compared to low sulfur coal, it is less expensive to purchase, costs little more to clean, and produces a valuable byproduct. With the relatively high sulfur content of Indiana coal (depending on the specific source), the proposed facility could produce a significant volume of marketable sulfur. As a nearby benchmark, the Wabash River gasifier facility produces in excess of 100 tons/day of elemental sulfur from processing 2,000 tons/day of feedstock.[23]

Pricing Considerations: Sulfur has a deep and diverse marketplace and pricing will depend on the specific form and purity of the captured product. Sulfur prices have risen since 2006, from an annual average of $32/ton in 2006 to $40/ton in 2007.

2.4.1.5: Slag:

Market Considerations: Slag is an inert, solid by-product of the coal gasification process. Slag is often used as clean fill, and has market value as aggregate depending upon its composition. The Wabash River facility sells all of its slag as aggregate and Duke expects to sell all of the slag produced at the proposed Edwardsport IGCC facility.[24]

Major slag markets include:

- A substitute for light-weight aggregate in the production of cement and concrete
- Road construction aggregate
- Structural fill materials
- Land fill cover

[23] *Indiana Coal Report 2006,* p.52.
[24] Personal communication with SAIC team member.

- Anti-skid materials for roads and highways
- Blasting grit, roofing tiles and other lower grade building requirements

Pricing Considerations: Air cooled slag for concrete aggregate, fill, road base covering, and snow/ice control was sold nationally in 2004/5 at an average price of approximately $15.50/ton. Other sources provide a 2006 price range for light aggregate from $9 to $19/ton. Depending upon the composition, proximity to customers, and the willingness to invest in processing the slag, a variety of higher value niche markets exist.[25]

For the purposes of this study, niche markets were ignored and focus was placed only on using slag as a substitute for light aggregates. Slag's market value as aggregate will, of course, depend upon the specific composition, the proximity of major customers and construction activity, and the availability and price of other sources of supply. In general, however, construction activity projections are so high for Indiana, and to a lesser extent for Kentucky and Illinois, that continued strong demand for aggregate is a safe assumption. Indiana Governor Mitch Daniels, *Major Moves* plan will more than quadruple state highway and road construction over a ten-year period. A market price for slag of $9 per ton was assumed.

2.4.1.6 CO_2:

Market Considerations: The basic site design will include CO_2 capture capability. As noted, discussions are underway with two firms interested in the commercial use of CO_2 produced.

Should the proposed CO_2 pipeline from Louisiana be completed to the Indiana border (as currently proposed), the State would very likely provide some support for the construction of a collector pipeline to connect a Southwestern Indiana project, the Edwardsport and Wabash River facilities, as well as other coal gasification sites. This would provide the infrastructure to potentially market all collected CO_2 in southwestern Indiana.

Pricing Considerations: Commercial markets for CO_2 are available for food and industrial applications, as well as for EOR. Quality requirements for food and beverage applications require very low hydrocarbon and sulfur impurity content. By far the largest market is for EOR and Denver City, Texas, is the world's largest CO_2 hub. Publicly quoted price ranges are quite wide and are infrastructure and location specific. Where infrastructure and customers exist, prices quoted range from $4/ton to $12/ton. A 2005 study of the potential for EOR for Illinois oil fields identified huge economic recovery opportunities if large quantities of CO_2 could be made available at $0.70/mcf assuming only a $25/barrel (bbl) price for crude.[26] This is one of a series of DOE projects that investigated the potential of applying state-of-the-art CO_2-EOR in key basins across the United States (recently updated). A recent estimate, based on the updated analysis, is that large CO_2 market demand for EOR exists at real oil prices of $70/bbl, and CO_2 cost of $45/mt (delivered).[27]

For the purposes of this analysis, an assumption was made that 25 percent of the CO_2 produced would be commercially sold at $4.00/ton.

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[25] Alaska CTL study, *op cit.*

[26] Advanced Resources International, Inc., *Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Illinois*, U.S. Department of Energy Office of Fossil Energy – Office of Oil and Natural Gas, March 2005

[27] Vello A. Kuuskraa, President, Advanced Resources International, "Maximizing Oil Recovery Efficiency and Sequestration of CO_2 with "Game Changer" CO_2-EOR Technology," January 2008, p. 11.

2.4.1.7 Alternative Products A major alternative to the F-T liquids process that fits the regional demand structure is a coal gasifier / anhydrous ammonia / fertilizer option. Fertilizer prices are extremely high and the price of natural gas represents 80 to 90% of production cost. As a result most anhydrous ammonia is imported from Trinidad where natural gas prices are low. It is therefore recommended that future analyses should further investigate and refine the economic potential of this as well as other select chemical products alternatives.

2.4.2 Capital and Operating Costs

2.4.2.1 Capital Cost Estimate Issues

Gasification and Power Systems Cost Estimates: Considerable information is available publicly and in DOE/NETL data concerning costs of coal handling and combined cycle electric power generation systems. A much smaller, but growing, body of data exists on commercial scale coal gasification facilities. Basic capital costs can be built up from the information available, with prices escalated to reflect current market conditions, and with uncertainty factors built in. Specific equipment choices and design decisions will significantly affect cost estimates.

F-T Systems Cost Estimates: On the other hand, there is very little published information regarding the overall and detailed cost for commercial scale F-T systems. Generally, the cost estimates are held as proprietary information. For this study, cost estimates have been determined using factored estimates after establishing the process flow diagram.

2.4.2.2 Capital and Total Project Cost Estimates A capital cost summary is provided in **Table 2.4.2.2-1** for the design. A more detailed capital budget is provided in **Annex D**. See **Table 2.4.2.2-2** for an estimate of Erected Plant Costs (EPC) and total project costs.

Table 2.4.2.2-1: Capital Cost: Conceptual Design		
Coal Feed:	2,704	Ton/day
Net Power:	25.1	MW, net
F-T Output:	6,099	F-T Liquids bpd

Acct No.	*Item/Description*	*TOT. PLANT COST $,000*
1	**Coal & Sorbent Handling**	$19,103.70
2	**Coal-Water Slurry Prep & Feed**	$29,080.90
3	**Feedwater & Misc Bop Systems**	$8,108.20
4	**Gasifier & Accessories**	$334,365.10
5A	**Gas Cleanup**	$96,860.40
5b	**Fischer-Tropsch Systems**	$134,489.70
6	**Combustion Turbine Generator**	$45,204.70
7	**Hrsg, Ducting & Stack**	$5,845.90
8	**Steam Turbine Generator**	$26,385.30
9	**Cooling Water System**	$7,879.70
10	**Ash/Spent Sorbent Handling Sys**	$26,855.00
11	**Accessory Electric Plant**	$7,166.90
12	**Instrumentation & Control**	$8,181.60
13	**Improvements To Site**	$7,633.40
14	**Buildings & Structures**	$6,741.80
15	**2.0 Mile Heavy Rail Track**	$5,744.50
16	**7 Mile PVC Water Main f/Lake, 1,000 GPM**	$3,991.60
17	**Power transmission to Grid**	$4,191.00
18	**Fuel Storage and Transfer**	$316.00
	TOTAL COST* **	**$778,145.40**

See Assumptions

* Cost includes CO_2 capture, but not compression and storage.
** Total project cost will be larger than the facility cost itemized here.

Table 2.4.2.2-2 Total Plant Cost (in thousand dollars)	
Capital Cost[1]	
EPC	$495,404
Project Contingency	$156,663
Process Contingency	$86,448
Engineering CM, H.O., & fee	$39,630
Other	0
Total Capital Cost	$778,145
Financing Cost[2]	
Interest During Construction	$64,125
Financing Fee	$13,897
Other	0
Total Financing Cost	$78,022
Other Project Cost (10% of Capital Cost)	$77,815
Total Project Costs	$933,982

1 Capital cost estimates provided by SAIC
2 Financing cost estimates based on factors included in Technical and Economic Assessment of Small-Scale Fischer-Tropsch Liquids Facilities, DOE/NETL-2007/1253, February 27, 2007.

For our reference design, total project cost is approximately $153,000 per bpd.

2.4.2.3 Operating Cost Estimate Operating costs are based on estimates from the 2007 NETL study, scaled to reflect the smaller size and adjusted to account for differing assumptions. See **Table 2.4.2.3-1** for the detail.

Table 2.4.2.3-1: Annual Operating Cost

Item	Costs ($1,000)
Fixed Operating Costs[1]	
Operating Labor	$17,765
Maintenance Labor	$9,034
Administrative and Support labor	$5,886
Total Fixed Operating Cost	**$32,685**
Variable Operating Costs[2]	
Maintenance materials	$9,741
Consumables[3]	
Water	0
Chemicals/Catalysts	$477
Waste Disposal	$9
Total Variable Operating Cost	**$10,227**
Coal Feed (2700 TPD @ $55/ton @ 85%)	**$46,072**
Total Annual Operating Cost, incl. coal	**$88,984**
Total Annual Operating Cost, excl. coal	**$42,912**

1 Staffing is assumed to be identical to that for the 4254 Tons per Day (TPD) reference plant in DOE/NETL-2007/1253. Smaller size does not significantly reduce the minimum workforce required to operate three shifts at this facility scale. This includes labor burden and overhead rates that cover all taxes and administrative charges.
2 Variable operating costs are scaled proportional to the coal feed (2700:4254 or 0.6347) compared to the reference plant in DOE/NETL-2007/1253.
3 Two major assumptions diverge from the reference plant in DOE/NETL-2007/1253. First, we assume no variable cost to water consumption. Second, we assume a market for slag as light aggregate and do not include waste disposal fees.

2.4.3 Revenue Estimates Based on the various assumptions and design criteria **Table 2.4.3-1** provides a summary of anticipated revenues once the facility is in full scale operation.

Table 2.4.3-1: Projected Revenues

Product	Market Price	Plant Output	Daily Revenue
Naphtha	$1.92/gal	2704 bpd	$218,051
Distillate	$2.89/gal	3394 bpd	$411,964
Wax	na	0 bpd	na
Total hydrocarbon product	na	6099 bpd	na
Gross power	na	71.8 MW	na
Net power	$60/MWh	25.1 MW	$36,144
Carbon dioxide	$4/ton @ 25% sold	3362 tons/day	$3,362
Sulfur	$40/ton	75.9 tons/day	$3,034
Slag	$9/ton	267.9 tons/day	$2,411
Total Daily Revenue			**$674,966**
Total Annual Revenue@85%			**$209,408,202**

With projected annual operating costs (including coal) of approximately $90 million the facility will be running annual net operating revenue over $120 million.

2.4.4 Business Case Modeling

2.4.4.1 Assumptions The base case economic assumptions are provided in **Table 2.4.4.1-1**.

Table 2.4.4.1-1: Model parameters and assumptions for Economic Analysis

Parameter / Assumption	Value
Construction Period	3 years
Incurred capital in: year 1	20%
year 2	50%
year 3	30%
Op year 1 availability (project year 4)	50%
Op year 2	70%
Op year 3 and beyond	85%
Plant lifetime	30 years
Depreciation method	double declining balance (15 years)
Debt Equity Ratio	70:30
Interest rate	10%
Tax Rate	38%
Other credits and incentives	10% investment tax credit
F-T diesel price	$2.89/gal
Naphtha price factor	$1.92/gal
Sulfur Price	$40/ton
Electricity price (sale continuous power)	$60/MWh
Slag price	$9.00/ton
CO_2 market price	$4.00/ton (assume only 25% sold)
Coal Price	$55/ton
Cost and price escalation	3% on everything

2.4.4.2 Business Case analysis The base case business analysis with the above assumptions yields a 18% internal rate of return and an 11 year payback period from the project launch (beginning of construction period). Given the levels of contingency built into project costs this base case provides a very conservative starting point for analysis. It is important to emphasize that except for an assumed 10 percent investment tax credit, no policy incentives are assumed.

Several tests of sensitivity are provided in **Table 2.4.4.2-1**. The results are all based on changing only one variable from the base case. Since the base case is positive, all sensitivity tests reported are negative to the base case.

Table 2.4.4.2-1: Economic Sensitivity Analysis

Scenario*	Rate of Return	Payback Period**
Base case	18%	11 years
EPC +20%	16%	11 years
15% interest rate	12%	18 years
50% D/E	14%	13 years
$70/t coal	14%	14 years
-20% price F-T	9%	20 years

*Each Scenario assumes one variable change from base case, as discussed in text.
**Time measured from beginning of construction.

EPC +20% assumed that we underestimated Erected Plant Costs (EPC) by 20 percent. This had only a modest impact on results.

15% Interest Rate assumes that the project would have to pay 15% interest for long-term debt. The return is still quite acceptable, but the payback period is lengthened considerably.

50% Debt-Equity Ratio (D/E) assumes that investors would be required to put substantially more equity into the project. The D/E is shifted from 70:30 to 50:50. Returns and payback remain acceptable.

$70/ton coal assumes that the cost of coal rises from the base case of $55 to $70 per ton. Again both returns and payback remain acceptable.

-20% price F-T is the most negative of the scenarios. This assumes that the prices of F-T diesel and naphtha decline 20 percent from the base case, with no other changes. Return drops below 10% and it takes 20 years from project launch to achieve payback.

2.4.4.3 Sensitivity Analysis Among the many analyses of CTL facilities, the same variables emerge in roughly the same order as most sensitive to assumption. In order of importance the top seven include:

- Diesel Price
- Facility Availability
- EPC
- Naphtha Price
- Delivered Coal Price
- Percent Debt Financing
- Tax Rate

2.4.5 Comparison to Other Analyses The analysis presented herein is in line with a variety of other recently published studies of CTL from various sources and using various coals. All of these studies tend to find that CTL is economic at crude oil prices substantially below current market prices ($100+/bbl). Depending upon a variety of assumptions, such as those listed below, and scale of the facility, these reports find that commercially profitable liquid fuels can be produced at risk adjusted crude oil prices in the range of $35 to $65/bbl without sequestration. The major recent reports are briefly summarized below.

- A SAIC/NETL Alaska-based 11,700 ton/day sub-bituminous (14,640 bpd F-T liquids) CTL facility design estimated:[28]
  - Total project cost of $2.24B
  - Operating cost (excluding coal) of approx. $100M
  - Production price (@12% Return on Investment (ROI)) of roughly $45/bbl oil equivalent (delivered sub-bituminous coal price of $15.30/ton)
- A Kentucky-based 5000 ton/day (10,000 bpd F-T liquids) CTL facility design estimated:[29]
  - Total project cost of $966M to $986M
  - Operating cost (excl. coal) of $58.1M to 61.0M
  - Production price (@15% ROI) of $50 per bbl oil equivalent (at $35/ton western KY coal)
- The recent Southern States Energy Board assessment of 16 CTL facility configurations from 5400 to 33,600 ton/day (10,000 to 60,000 bpd F-T liquids) estimated:[30]
  - Total project costs from $977M to $4.67B
  - Annual operating cost (excluding coal) of $63.5M to $296.0M
  - Production price (@15% ROI) of $35/bbl to $55/bbl oil equivalent (bituminous coal price $36/ton)
  - Various risk contingencies raised the oil threshold price to some $65/bbl oil equivalent

[28] NETL, *Alaska Coal Gasification Feasibility Studies – Healy Coal-To-Liquids Plant*, DOE/NETL-2007/1251, Final Report, July 2007.

[29] University of Kentucky, Center for Applied Energy Research, *Technologies for Producing Transportation Fuels, Chemicals, Synthetic Natural Gas and Electricity from the Gasification of Kentucky Coal*, July 2007.

[30] Southern States Energy Board, *The American Energy Security Stu: Building a Bridge to Energy Independence and a Sustainable Energy Future*, 2006, www.AmericanEnergySecurity.org.

- A 2007 NETL study on small scale CTL facilities using a 4254 ton/day (9,609 bpd F-T liquids) estimated:[31]
  - Total project cost of $976M
  - Annual operating cost (excl. coal) of $52M
  - Production price (@14% ROI) of $55/bbl oil equivalent (bituminous coal price $55/ton)

- 2008 SAIC/CCTR base case using a 2,704 ton/day (6,099 bpd F-T liquids) estimated[32]:
  - Total project cost of $934M
  - Annual operating cost (excluding coal) of $43M
  - Production price (@18% ROI) of $75/bbl oil equivalent (bituminous coal price $55/ton)
  - Production Price (@ 10% ROI) of $60/bbl oil equivalent (bituminous coal price $55/ton)

2.5 Economic, Technical and Political Challenges All of the studies reported above, and many others, have examined key economic assumptions and have assessed the most critical risks and sensitivities. There is broad consensus on the most critical issues that must be addressed in order to prepare for a commercial launch of a small scale CTL facility that meets the State of Indiana goals. These are summarized here and addressed again below in the policy discussion.

2.5.1 Key CTL Risks:

- Economic Risks
  - Collapse in market price of oil
  - Financing of large, complex, projects
    - Identification of lead investor/source of funds
    - No US-based team with track record in commercial CTL

- Design/Build/Operation Risk
  - Systems engineering and integration
  - Rapid construction cost escalation
  - Skilled labor availability
  - US commercial scale F-T system operations not demonstrated

- Competitive technology risk
  - Alternate processes for synthetic liquid fuels,
  - Electric vehicles

- Political/policy changes

- Total carbon footprint of Coal to Liquids facility compared to alternatives

2.5.2 Economic Risks

2.5.2.1 Crude Oil Price The single most important variable emerging from economic risk analysis is the market price of crude oil and the resulting selling price of F-T liquids. The price of crude sets the price structure for all fossil fuels. Previous US government interest and

[31] *Technical and Economic Assessment of Small-Scale Fischer-Tropsch Liquids Facilities*, DOE/NETL-2007/1253, Final Report for Subtask 41817.401.01.08.003, February 27, 2007.
[32] Estimated for this study.

investments in coal gasification and liquefaction in the 1970s were derailed by a sharp drop in world crude prices. With current oil prices in excess of $100/bbl and a consensus that a sustained price in the $50/bbl range would support economic CTL, a strong case can be made that the time is now to jump start the first US-based commercial-scale operation.

On the other hand, part of the high market price of crude oil reflects the weak US dollar. Trying to calculate a potential long-term equilibrium crude price thus requires making some assumptions about long term exchange rates. Without going into the complexities, and weaknesses, of calculating so-called real exchange rates, we use the purchasing power parity rates reported in the online World Bank, *World Development Indicators* data set to compute a rough real exchange rate between the dollar and the euro and use that to deflate the market price of oil. This is only a rough approximation, but serves to illustrate that if the currencies moved towards 2008 real exchange rates (US dollar gain in value) and nothing else affected the price of oil, the US dollar price of today's $100/bbl oil would be around $73/bbl.[33] This price remains high relative to the profitability points noted above, and the long term outlook for oil prices suggests that they will continue to rise and that OPEC is unlikely, and perhaps unable, to stem the rise on a sustained basis.

To the extent that policy can help stabilize or put a floor under the market price of oil or provide price supports on the output of CTL facilities, the investor community would be able to significantly discount the risk of another price collapse.

Among the options available for reducing oil price risk are:

- Negotiation of a price band for F-T diesel with the State. The facility is small enough and State demand for diesel large enough that it may be possible to establish a price band where the state would commit to pay a minimum price for some or all diesel output in return for a commitment to sell diesel to the state at a negotiated cap should market prices rise above that ceiling.
- Offering a state fuel tax reduction / credit on each gallon of F-T diesel (perhaps on a sliding scale based on market price).
- Negotiate long-term off-take contracts with major customers (which may include Crane)
- The State can provide incentives for customers to negotiate such long-term contracts (e.g., a tax credit or rebate for fuel consumption that is produced with Indiana coal or biomass).

Of course Federal actions are also possible, and would be extremely helpful.

- The Federal government could provide purchasing support through long-term guaranteed fixed price contracts (this would require dealing with the new lifecycle greenhouse gas ruling in the 2007 Act – more on this below).
- The $0.50 per gallon fuel excise tax credit for alternative fuels could be granted to new CTL facilities and extended well past its current September 2009 expiration date.[34] (Some proposed extensions under discussion include strong lifecycle greenhouse gas

[33] Germany was used as the most inflation conservative member of the Eurocurrency bloc. The estimated German purchasing power parity for early 2008 was compared to the US, which in turn was used to adjust the current euro-dollar exchange rate to a proxy for a longer-term equilibrium rate. Preparation of a comprehensive trade-weighted real exchange rate for tracking oil prices is beyond the scope of this analysis, but the order of magnitude estimate presented in the text provides us some confidence that a longer term correction in currency markets will not wipe out profitability. Data can be found at http://web.worldbank.org/WBSITE/EXTERNAL/DATASTATISTICS/.

[34] Joint Committee on Taxation, List of Expiring Federal Tax Provisions 2007-2020 (JCX-1-08), January 11, 2008.

language). By itself this can be the equivalent of additional $20/bbl revenue on finished F-T product.

2.5.2.2 Financing Risk Launch of an early stage, high investment cost, energy technology brings a relatively high capital risk This capital risk incorporates such factors as the premiums associated with financing and building large projects, the potential for construction delays and cost increases, regulatory and siting challenges, and product price uncertainty. Investors will, of course, expect higher hurdle rates of return to compensate for these risks.

Moreover, there are no large companies or consortia with meaningful commercial scale CTL experience to take the lead and bear a significant portion of the risk on projects of this scale. A team of organizations would have to be assembled, not only to share the risk but to provide deep expertise in the various component technologies that must be integrated.

Policy at the Federal and State level can have strong leverage on financing and financial risk. Loan guarantees and production tax credits are particularly attractive. Economic policy analysis from various studies provides similar conclusions regarding commonly-used Federal and State fiscal and tax incentives. The 2007 NETL study provides the following conclusions:[35]

- Loan guarantees have the largest impact, increasing the ROI by five percentage points or more from the base case
- Investment tax credits provide a two percentage point increase in ROI
- State bonds provide less than a one percentage point benefit
- Production tax credits could increase the ROI by two to eight percentage points depending on their magnitude and how the incentives are credited

2.5.3 Design/Build/Operation Risk Although the individual processes required for a CTL facility have been demonstrated world-wide, the system engineering and integration capability has not been developed in this country yet, and would require attention during the planning phase. When designing and building large and complex projects, considerable opportunity exists for costs to escalate and plans to require substantial modification during the process. Construction costs have escalated and scheduled delays are more prevalent in recent years resulting in projects coming in over budget and behind schedule. China (along with several other countries) has engaged so many key players in the coal gasification and CTL industry that a small US project could face significant manufacturing delays for major systems and components. Additionally, there is a lack of actual CTL facility building experience in the US.

Although the core technologies of coal gasification and F-T processing are not new or unproven, the lack of actual operating plants within the US would require engineering and operator expertise to be developed.

Moreover, with what essentially could be called a new design when compared to a traditional power plant or a refinery, considerable effort must be focused on enhancing the reliability of the commercial operation.

Some strategies include:

- Technology vendors and/or the engineering, procurement, and construction companies could be incentivized to offer performance guarantees.
- Evaluation of all F-T current and emerging technology sources (reference **Annex B**).

[35] *Technical and Economic Assessment of Small-Scale Fischer-Tropsch Liquids Facilities, op cit,* p 11.

- Experienced staffing/management concerns can be eased with focused attention paid to training and education from the onset. Since Indiana is already home to the Wabash gasification facility and will soon see construction begin on the Edwardsport IGCC facility this could prove beneficial to all. Working with these facilities and in concert with Purdue University, Ivy Tech Community College and Vincennes University (among others), CCTR is beginning to investigate the expertise needed and options to ensure that expertise will be available.
- The State, through the CCTR, can support aggressive investigation of a range of technical issues to determine how to ease some of the risks associated with the adoption of CTL as well as other coal-based technologies.[36] Among many others, such topics include:
    - Gasification alternatives, especially for the integration of biomass/biowaste streams.
    - Process improvements in gas cleaning and conditioning, both to reduce cost and optimize Syngas production for F-T performance.
    - Improvement in F-T catalyst processes, costs and life expectancy.
    - Improvement in the ability to select, enhance and optimize product mix in the F-T refining process for select products or customer requirements.
    - Collaboration with turbine and diesel engine manufactures to meet current and future commercial and defense applications.

2.5.4 Competitive Technology Risk

2.5.4.1 Efficiency and Conservation The US vehicle fleet (ground, air, and water) has become substantially more energy efficient over the three decades since the first oil-shock, and will continue to improve. Efficiency gains, will be evolutionary not revolutionary however. With current much higher liquid fuel prices, which are expected to persist, we should also begin to see behavior changes to select more fuel efficient vehicles, reduce travel, and seek alternatives (such as increased telecommuting).

2.5.4.2 Alternate Processes for Synthetic Liquid Fuels A vast amount of research is being devoted to alternatives to Fischer-Tropsch liquefaction, including improving current biofuel technologies, and developing processes for cellulosic conversion. At this point, many approaches are interesting, but none are developed enough to appear to offer significant cost advantages over Fischer-Tropsch within a relatively near-term investment horizon.

2.5.4.3 Electric Vehicles Electric, hybrid electric, and plug-hybrid vehicles (including fuel cell / hydrogen powered vehicles) all offer significant opportunity to reduce the growth in liquid fuel demand. However, even the most optimistic projections show the market penetration of such vehicles only accounting for a modest reduction in petroleum imports, much less total liquid fuel consumption.

Approximately 60% of petroleum consumption is currently imported. Even with some of the improvements noted, USDOE projections show import dependency headed towards 70% by 2025. These same projections all suggest prices will also continue to rise as the US competes with many other countries, especially China and India for petroleum. Barring a major technology leap, or a change in energy policies in this country, the US demand for liquid fuels and thus imported petroleum will continue to rise.

[36] Most of these process research issues are discussed in more detail in Kentucky, *op cit*, Chapter 4.

2.5.5 Political/Policy Change Investors have watched the wax and wane of public policy support for CTL, and are cautious about committing to large commercial scale projects that depend upon sustained policy support for long-term profitability. The most recent new source of uncertainty is the debate over greenhouse gasses and the extreme policy positions taken by some environmental pressure groups and political leaders. With crude market prices soaring, the convergence of forces noted in the introduction to this document has certainly caught investor attention. The economics of CTL are increasingly attractive. Key political policy concerns remain.

2.5.5.1 Changing Federal Policy towards CTL The *Energy Policy Act of 2005* provided incentives for clean coal and gasification deployment, including tax credits, loan guarantees, loans, and direct grants. Some of the more significant of the incentives had to be claimed within a three year window of enactment. The longer-term incentives that may be accessible to the proposed project are:[37]

- The Energy Policy Act enabled the DOE to provide US$200 million annually for nine years (2006 to 2011), for a total of US$1.8 billion, as loan guarantees, loans, and direct grants to gasification and other clean coal project developers (70% must be for gasification projects).
- Provisions under the Clean Air Coal Program aimed to increase efficient and economic use of energy to promote national energy security, diversity, and environmental performance. Authorized appropriations under this provision for new projects for 2007 to 2013 total US$2.5 billion.
- The Energy Policy Act also provided royalty incentives to promote enhanced oil production through injection of carbon dioxide and established a demonstration program to increase sequestration of CO_2 in enhanced oil recovery projects.

It is unclear how many of these incentives remain available to new applications, and whether funds will be appropriated. The proposed project certainly would qualify as a potential candidate if funding is available.

The *Energy Independence and Security Act of 2007* introduced relatively few, but important, provisions directly impacting clean coal.

- First, **Title 5-Energy Savings in Government and Public Institutions, Subtitle C-Energy Efficiency in Federal Agencies, Section 526-Procurement and Acquisition of Alternative Fuels**, "…prohibits federal agencies from entering into procurement contracts of alternative or synthetic fuel for any mobility-related use, other than for research or testing, unless the contract specifies that the lifecycle greenhouse gas emissions are less than or equal to emissions from the equivalent conventional fuel produced from conventional petroleum sources."[38]

- Second, **Title 7-Carbon Capture and Sequestration, Subtitle A-Carbon Capture and Sequestration Research, Development, and Demonstration, Sections 702 and 703** authorizes significant funding.[39]

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[37] See ICF International, *Impacts & Implications of the 2005 U.S. Energy Policy Act*, a series of Issue Papers from ICF International Experts, August 5 2005.
[38] Alliance to Save Energy, *2007 Energy Bill Detailed Summary*, p. 17.
[39] *ibid*, p. 24.

- **Section 702- Carbon Capture and Sequestration Research, Development, and Demonstration Program** authorizes $240 million per year for FY08 to FY12 for sequestration research, development, and demonstration.
- **Section 703-Carbon Capture** authorizes $200 million per year for FY09 to FY13 for DOE to carry out a program to demonstrate technologies for the large-scale capture of CO_2 from industrial sources.

The first provision directly hinders DoD, especially the Air Force, plans to aggressively pursue a CTL strategy to develop domestic sources of synthetic JP-8 for flight operations. It also has triggered serious criticism from Canada, whose development plans for their extensive oil sands include F-T liquefaction. Reps. Jeb Hensarling and Mike Conaway have filed a bill to repeal Section 526.[40] Concern has been raised that without long-term federal contracts, it may be difficult to create the price stability required to launch the first commercial scale CTL plant.

The carbon capture and sequestration provisions could work positively for the proposed project. If appropriated, the authorized funding could represent a substantial contribution to the success of the proposed project. As a smaller, but still commercial sized CTL facility, close to both EOR and pure geologic sequestration potential, the proposed facility and its timing are a good fit to meet the legislation's objectives.

The following is a list of a variety of other items are under discussion to promote clean coal at the federal level, but prospects for enactment are unclear.[41]

- Approval of long-term purchase contracts.
- Authorization and appropriation of significant deployment funding for an initial group of CTL facilities.
- Appropriation of loan guarantee funding authorized in the Energy Policy Act of 2005.
- Provision of investment tax credits (say 20% with a cap) and 100% expensing of investment in year of outlay for CTL facilities put into service during the next decade.
- Extension of the temporary expensing allowance for equipment used in refining to 100 percent of any required additions to existing refineries needed to handle domestic alternative liquid fuels products – thus redirecting refinery owners towards using domestic feedstocks.
- Elimination of the $10 million cap for tax exempt Industrial Development Bonds for alternative liquid fuels facilities. To encourage investment, certain pollution control and solid waste disposal facilities are currently not included in the $10 million limit on tax exempt Industrial Development Bonds (IDBs). Alternative liquid fuels production facilities could be added to this list of activities having no tax exempt IDB size limits.
- Provision of increased incentives for enhanced oil recovery and enhanced coal bed methane recovery using CO_2 captured from alternative fuel facilities. The capture and use of the CO_2 from alternative liquid fuel facilities can greatly expand domestic oil production from existing oil fields and enhance methane recovery from coal bed methane

[40] See Ben German, *E&E Daily*, April 1, 2008, "Climate: Hensarling seeks repeal of energy law procurement language" for one of many recent press discussions of the contentious debate triggered by Section 526.

[41] These various federal proposals have been recommended by multiple parties and in multiple venues. Detailed references are not provided, but many of the federal and state policy proposals discussed herein are explored in some detail in *The American Energy Security Study*, *op cit.*

operations. Some actions that will lower barriers to expanded use of CO_2 injection include:

- Exclusion of the oil produced from the Alternative Minimum Tax
- Increasing the investment tax credit to 50 percent
- Provision of federal royalty and severance relief until the investment in CO_2 injection is recovered
- Provision of access to federal lands for construction of CO_2 pipelines

2.5.5.2 State and Local Policy Options Besides taking advantage of the described federal incentives and promoting the adoption of additional incentives, a variety of other mechanisms are available to investors and States to help offset the high hurdle rates.

- The technology vendor, the engineering, procurement, and construction company, and/or other project partners (utility, refinery, etc.) can take equity positions and share risk.
- The State can authorize and fund multi-year state and local government purchases of alternative transportation fuels.
- The State can offer financing incentives for early adopters. It can provide:
  - matching loans or grants to private industry to assist with preliminary engineering and site qualification
  - project loans at favorable rates
  - qualification for industrial development bonds
  - loan guarantees.
- The State and local governments can offer tax incentives, such as:
  - Investment tax credits
  - Corporate tax abatement/credits
  - Property tax abatement.
- The State can become an investor in the total project, especially as it relates to establishing the "R&D Center" and assuring Crane "energy independence," by providing bond and grant financing of required physical infrastructure (roads, power lines, gas and water pipelines, etc.) and potentially supporting CO_2 sequestration infrastructure.
- With regard to the latter, the States can incentivize the use of CO_2 for carbon capture and storage
  - Provision of state royalty and severance tax relief until the investment in CO_2 injection is recovered
  - Provision of access to state lands for construction of CO_2 pipelines

A strong State commitment to CTL deployment at the most senior levels can be as important as specific incentives. Funding is critical, but so is serving as an aggressive convener to bring together appropriate partners in an effort to assemble the best team to carry the project forward.

Permitting Support: Although coal gasification is in widespread use worldwide, the US has limited commercial experience and regulators have been slow to approve facilities based on coal gasification. More than 15 gasification projects are being proposed nationwide. Recently there has been a surge in progress through the approval process for gasification projects.[42] This gives the community some confidence that utilities and regulators are beginning to reach consensus on

[42] There are 142 operating gasification plants (not IGCC plants) with a total of 420 gasifiers in operation worldwide, as reported by Steve Jenkins, CH2M HILL, "Gasification 101," presented at the Gasification Technologies Council Workshop, March 13, 2008, pp. 18, 19, and 43.

an array of fundamental issues around coal gasification. The F-T process is simply a refinery process that, under current rules, should face no insurmountable regulatory barriers. For states wishing to encourage coal gasification technologies, it is imperative that special attention be given to preparing the regulatory process to facilitate speedy consideration and review. The State can initiate a process to provide regulatory streamlining and coordination of the permitting process for alternative liquid fuels, including:

- Pre-qualification of sites
- Identification of options to meet air and water requirements
- Standardize and expedite permitting and siting under established timelines with joint federal, state and local processes, policies, and initiatives
- Make appropriate state and local government sites available for alternative transportation fuels manufacture
- Encourage local authorities to modify approaches to zoning and other land use and business regulations to accommodate alternative transportation fuels production facilities

2.6 Conclusions and Recommendations

This study concludes that while additional planning is required and risks exist in this volatile energy environment, that this design concept and/or related concepts could be economically and technically viable, contingent upon acceptable mitigation of risk. The only exception from a commercial viability standpoint may be the ability to provide a R&D capability as it may require a substantial non-commercial subsidy. Risk areas as described above that must be addressed include the price of crude oil, systems engineering and integration, construction and commodity costs including coal, and any possible CO_2 tax, legislation, and regulation. The opportunities realized may be quite substantial. Benefits could include reduced reliance on foreign oil, enhanced use of Indiana coal, more Indiana jobs, advances in technology and processes, industry profitability, and creation of regional supply for transportation fuels. In terms of risk, we believe the following:

Cost: It appears likely that the price of crude oil will remain high enough to support a business case for a CTL plant, even assuming an adjustment to a historically more appropriate exchange rate for the dollar.

Technical: The technical risk that this country has not yet demonstrated the ability to build a full cycle CTL plant can be mitigated. This can be done to a reasonable level by assembling the right team of "sub process" industry, academia and government experts, e.g. coal gasification, power generation, fuel refining, F-T process, construction, systems engineering, CO_2 compression and storage, and applying rigorous system engineering processes.

CO_2: The management of CO_2 issues represents a major technical and financial risk. The next 12 to 18 months should clarify the nation's position on CO_2 taxation and associated legislation and regulation. Numerous initiatives have been and are being mobilized to address CO_2 emissions, from Algae to full scale geologic sequestration, via DOE and state initiatives. Indiana, for example, is a member of a DOE funded state regional coalition and is in turn funding an initial sequestration project in Southwest Indiana. A project with output the size of this plant might not have to wait for a global solution to geologic sequestration, which may be potentially years away. As described, there are local CO_2 sale opportunities, and multi-state planning is ongoing for a CO_2 pipeline joining Indiana with EOR opportunities in the southwest, in the next

3 or 4 years. These two opportunities could satisfy future CO_2 emission requirements, especially for a "first plant" that could negotiate long term sales contracts. The inclusion of biomass as a feedstock with coal feedstock could also be evaluated, especially in Southwest Indiana, to further reduce carbon footprint.

Coal: The DOE Energy Information Agency (EIA) predicts that the percentage of energy supplied by coal will actually increase over the next twenty years. It seems prudent to continue to plan, to develop advanced clean coal technology, and to be well positioned as a State to react as solutions develop and market conditions dictate.

We specifically recommend the State of Indiana continue to aggressively motivate and incentivize the pursuit of clean coal technologies. Indiana has the natural resources readily available, the space required, the utilities necessary, and the drive to advance its technological aptitude in order to compete in today's rapidly evolving market. It is recommended that additional planning be done to accomplish the following:

- Develop a State-wide coal to alternative products strategy (liquid fuels, SNG, fertilizer, chemicals, electric power), including policy options and initiatives
- Position Indiana as a lead player in the effort to implement solutions to CO_2 management, with special attention to carbon dioxide management, product resale options, new technologies, enhanced oil recovery via pipeline and sequestration
- Determine the feasibility of coal/bio-mass feedstock mix for clean coal applications.
- Evaluate optimum locations state-wide, including Army National Guard sites

Annex A: Environmental Studies and Required Permits

A.1 Executive Summary The following summary of potential environmental requirements is based on the current level of detail available regarding the design of the proposed Coal-To-Liquids production facility. The enclosed information is preliminary and is subject to change based upon any revisions to the proposed project. The total cost for environmental permitting is estimated at $1,118,850 and the total estimated cost for environmental studies is $319,200 for a combined total of approximately $1.5 million dollars. Anticipated periodic maintenance, inspections, permit-required sampling, and reporting costs are not included in the estimate.

The Coal-To-Liquids facility will require multiple federal and state jurisdictional permits and assessments. Although a carbon dioxide (CO_2) gas storage well is not proposed in the current facility design, the permitting information is included for reference. It should also be noted that this report does not cover process related wastewater treatment facilities. If the facility expands its design efforts to include treatment facilities in order to meet prescribed water quality effluent limits, additional information and consideration will be required. Once the final facility design is received, a determination can be made as to which permits or assessments are required, need to be modified, or can be eliminated.

The following permits were evaluated for their applicability; Air Construction and Operation permits, Gas Storage Well permit, Indiana Department of Natural Resources (IDNR) Construction / Flood Control permit, National Pollutant Discharge Elimination System (NPDES) permit, Resource Recovery and Conservation Act (RCRA) permit, Sanitary Sewer construction permit, Solid Waste permit, Storm Water construction permit, and impact to Waters of the State permits.

The following environmental studies were evaluated for their applicability; Archaeological / Cultural Resources survey, Biological / Natural Resources / Natural Heritage data evaluation, Geotechnical evaluation, National Environmental Policy Act (NEPA), Phase I Environmental Site Assessment (Phase I ESA), Phase II Environmental Site Assessment (Phase II ESA), Pipeline Oil Spill Prevention and Response Plan, Pollution Prevention (P2) Plan, Spill Prevention Control and Countermeasures (SPCC) Plan, and Water Withdrawal Registration.

It is required that the facility personnel contact, meet, and work with the Indiana Department of Environmental Management (IDEM) prior to applying for the Air construction and operation permits. Although not required, it is strongly recommended that the facility personnel work closely with both federal and state organizations during all design, permitting, and construction phases.

Based on the design data available it is highly recommended that as part of the site selection process, the facility should be located in an area that will adequately facilitate the daily volume of discharged water without causing harm to human life or the environment due to flooding.

During the review of the potential permits and environmental studies, some exceptions to the requirements were identified;

- A RCRA hazardous waste storage permit will not be required so long as no hazardous waste is stored at the facility over ninety days. The facility will however be required to register as a hazardous waste generator and will be required to obtain a federal identification number.

- A Sanitary Sewer construction permit will be required only if the facility needs to construct a sewer extension for the disposal of sanitary waste.
- A Solid Waste permit will not be required unless the facility wishes to establish solid waste disposal onsite. The facility will however be responsible for identifying and characterizing its wastes so as to properly dispose of them.
- A Phase II ESA will only have to be conducted if the results of the Phase I ESA identify any potential contamination issues at the site.
- An Oil Spill Prevention and Response Plan will only be required if the facility's pipeline system meets the regulatory specified length, diameter, and proximity to a public water supply or environmentally sensitive area.
- A SPCC Plan will only be required if the facility meets a specific storage capacity for petroleum products.
- The facility will have to register with the Indiana Department of Natural Resources (IDNR) as a significant water withdrawal facility if the facility is designed with the capacity to withdraw water at a rate equal to or greater than 100,000 gallons per day.

It should be noted that if the facility receives any federal funding or if a federal organization has a significant vested interest in the project, it will be the responsibility of the federal agency to make the necessary provisions to comply with the National Environmental Policy Act (NEPA). Based on relevant experience, it can be expected that federal involvement will require that an Environmental Impact Statement be developed under the NEPA. Similarly, if the facility receives any federal funding or federal vested interest, it will also be required to construct a P2 Plan.

The following tables list the permits and studies that may be required to construct the Coal-To-Liquids Facility.

Table A.1-1 Coal-To-Liquids Facility Permitting Summary				
Permit	**Regulation**	**Regulatory Agency**	**Estimated Timeframe**	**Approximate Cost**
Air (construction and operation)	40 CFR 72 / 326 IAC 2	IDEM	18 Months	$200,000
Gas Storage Well	40 CFR 144 / 312 IAC 16	IDNR	3 Months	$11,000 Permitting only
IDNR Construction permit / flood control	IC 14-26 - IC 14-29	IDNR	2 Months	$2,000-$15,000
NPDES (wastewater, and storm water)	40 CFR 122 / 327 IAC 2	IDEM	21 Months	$65,100
RCRA HW Storage	N/A *Permit required only if store HW > 90 Days*	IDEM / EPA	2 Weeks	$100 to obtain HW generator ID (is NOT a permit)
Sanitary Sewer Construction	327 IAC 3	IDEM	2 Months	No permitting fee
Solid Waste	N/A	*Only required if operating waste disposal site*		
Storm Water Construction	327 IAC 15	IDEM	4 Months	$796,650
Waters of the State (includes Wetland study)	Section 401 Water Quality Act	IDNR/IDEM/ USACE	14 Months	$31,000

Total Estimated Cost: $ 1,118,850

CFR - Code of Federal Regulations
EPA - *United States* Environmental Protection Agency
HW – Hazardous Waste
IAC - Indiana Administrative Code
INDOT - Indiana Department of Transportation
IDEM - Indiana Department of Environmental Management
IDNR - Indiana Department of Natural Resources
–
NEPA – national Environmental Policy Act
NPDES - National Pollutant Discharge Elimination System
P2 - Pollution Prevention
RCRA – Resource Conservation and Recovery Act
SPCC - Spill Prevention Control Countermeasure Plan
SWP3 – Storm Water Pollution Prevention Plan
USACE - United States Army Corp of Engineers

Table A.1-2 Coal-To-Liquids Facility Specialized Assessments and Studies Summary				
Assessment	**Regulation**	**Regulatory Agency**	**Estimated Timeframe**	**Approximate Cost**
Archaeological Surveys / Cultural Resources	36 CFR 61 / 36 CFR 800	IDNR / State Historic Preservation Office	7 Months (and apply 6 months in advance)	$172,000
Biological/Natural Resources /Natural Heritage Data	36 CFR 800	IDNR	10 Months (and apply 6 months in advance)	$97,100
Geotechnical Evaluation	675 IAC 13	Indiana Fire and Building Code Enforcement	3 Months- Entire construction phase	Cost should be included in construction bid
NEPA	N/A	*Only required if facility receives federal funding.*		
Phase I Environmental Site Assessment	42 U.S.C. § 9601	Normally required by lending institution	3 Months	$6,000-$10,000
Phase II Environmental Site Assessment	42 U.S.C. § 9601	Normally required by lending institution	3 – 5 Months	$6,000-$12,000
Pipeline Oil Spill Prevention and Response Plan	49 CFR 190 – 49 CFR 199	INDOT	6 Months	$12,000-$16,000
P2 Plan	N/A	*Only required if facility receives federal funding*		
SPCC Plan	40 CFR 112	EPA	3-6 Months	$10,000-$12,000
Water Withdrawal Registration	IC 14-25-7-15	IDNR	2 Weeks	$100

Total Estimated Cost: $319,200

CFR - Code of Federal Regulations
EPA - *United States* Environmental Protection Agency
HW – Hazardous Waste
IAC - Indiana Administrative Code
INDOT - Indiana Department of Transportation
IDEM - Indiana Department of Environmental Management
IDNR - Indiana Department of Natural Resources
N/A – Not Applicable
NEPA – national Environmental Policy Act
NPDES - National Pollutant Discharge Elimination System
P2 - Pollution Prevention
RCRA – Resource Conservation and Recovery Act
SPCC - Spill Prevention Control Countermeasure Plan
SWP3 – Storm Water Pollution Prevention Plan
USACE - United States Army Corp of Engineers

Annex B: Overview of Major Process Steps and Alternatives for Producing Hydrocarbon Liquids from Coal

B.1 Coal Gasification Commercial technologies available for the production of synthesis gas from coal can be grouped into two major categories; dry and slurry feed systems. The dry feed system sends coal into the gasifier without any significant amounts of water that is converted to steam in the combustor. The oxygen to carbon molar feed ratio in this system is approximately 0.42 which leads to the maximum amount of synthesis gas. Commercial systems are available through Shell and Siemens. These systems can produce in the range of 1.5 to 2.0 barrels of liquids (pentane and higher hydrocarbons) from the Fischer-Tropsch synthesis per ton of coal (assuming the carbon content of the coal is greater than 70 wt %). Number 6 coal meets the requirements of the dry feed system. These systems have been designed to produce as much synthesis gas as possible while minimizing the energy of combustion through the relatively low oxygen in the feed.

The slurry-feed system utilizes a feed system that sends the coal to the combustor in a water-slurry mixture. In this system, the oxygen to carbon molar feed ratio is on the order of 0.62. The added oxygen provided by the water in the slurry increases the relative amount of combustion (and resulting higher carbon dioxide production) compared to the dry feed system. Converting the water to steam in the slurry absorbs the additional combustion heat such that the operating temperature in this system is similar to that in the dry coal gasification system. The added heat release is recoverable through the quench cooling of the exit gas which generates high pressure steam. Commercial systems that use the slurry feed systems are available from companies such as General Electric and Conoco Phillips.

Both technologies generate comparable hydrogen to carbon monoxide synthesis gas ratios (H_2/CO). However, the dry feed system generates approximately 15% to 30% more combined hydrogen and carbon monoxide per unit volume in the synthesis gas. The primary difference in the composition of the generated synthesis in the two systems is the quantity of carbon dioxide.

Both gasification systems can employ a quench heat boiler to generate high pressure steam as the synthesis gas is cooled from the typical exit temperature of 1800 to 2000°F to approximately 500°F. The slurry system with the higher oxygen content will generate significantly more energy in the form of steam due to the higher rate of combustion caused by the presence of water in the slurry feed. This is an advantage when considering integration with power generating facilities.

All of the commercial gasification systems must deal with particulates in the hot exit gas. The exit gas is too hot to perform contaminant removal (scrubbing) and the temperature needs to be reduced to less than 800°F and more typically to less than 500°F to initiate these activities. Consequently, particles are typically removed from the hot exit gas using cyclones. However, smaller particles not captured by the cyclone will typically pass on with the gas to the down stream cooling/quench exchange systems. These particulates can foul quench exchanger surfaces causing shut down in the best case scenario. The quench exchange systems are very expensive pieces of equipment due to the high pressure service, large temperature gradients and the metallurgy associated with minimizing metal dusting.

The exchanger in the dry feed system operates at more severe conditions relative to the slurry feed system. The Siemens technology is moving away from the use of a quench heat exchanger and replacing it with a direct water quench system.

The use of a direct water quench results in a loss in operating efficiency since the heat from the hot exit gas is not recovered by generating steam. However, elimination of the quench exchanger saves capital and potential operating time loss caused by surface fouling. Shell may also be moving away from the quench exchanger and using direct water injection for cooling to the 300 to 500°F required for down stream processes. It is not clear if the high oxygen slurry feed systems are moving away from the use of quench exchangers. These systems face the same particulate fouling of the exchanger surface and the issues related to operating factors can be a concern. The primary advantage of the high oxygen slurry coal feed system is the generation of high pressure steam through the waste heat exchanger. Operations with direct water quench cooling system (elimination of quench exchanger) reduce operational concerns associated with fouling but there is a lost in the amount of recovered energy (circa 5 to 10%) but this gasifer configuration should be considered since it may offer advantages with respect to capital and/or operating cost. Additionally, the direct quench configuration may offer additional advantages if it is found to be more compatible with Syngas conversion chemistries such as Fischer-Tropsch that utilize a 2:1 H_2 to CO feed ratio.

A major capital and energy cost involves the synthesis gas clean up. The Rectisol process is the leading technology with respect to current commercial applications. Cost information on this technology does not appear to be publicly available since it is a combination of licensing fees and the specific configuration for each gasifier. A factored cost estimate (beyond scope of this study) is possible based on maximizing the heat integration of the multiple flash steps and the two principal towers. The current maximum sizing of a Rectisol unit is equivalent to 14,000 bpd (2/1 ratio). However larger sizes (17,000 bpd) are supposedly being built in China.

B.2 Simplified Process Schemes for Coal Gasification to Fischer-Tropsch (F-T) Liquids There are numerous options associated with the integration of a F-T system to a coal gasifier. The major issue involved is: how much of the Syngas energy is committed to products as opposed to export energy? The capital and product (energy and F-T liquids) tradeoff is strongly dependent upon site specific issues involving water management. This annex will step through the major components of the currently proposed project, based on the most recent DOE/NETL reference design and highlight select problematic issues in the processing scheme and catalyst system that will need to be addressed in a future detailed design. Following this overview, some of the optional design criteria and schemes will be discussed.

B.2.1 Select Issues Associated with the Reference Design Iron Catalyst Process Scheme Based on DOE/NETL-2007/1253

The flow scheme presented needs to be refined with respect to the amount of naphtha and diesel produced per ton of coal. Typical F-T product selectivities are in the range of 10 to 20 mole % hydrocarbon gases (C1 to C4) with the remaining material consisting of liquid products C5+. This selectivity range is primarily due to the operating temperature where higher values increase catalyst productivity while lower temperatures reduce the amount of lighter hydrocarbons.

Recycling these light hydrocarbon products through an auto thermal reformer (ATR) would allow higher yields of C5+ products but product yields may not reach the assumed 2.25 barrels (bbl) of product per ton of feed carbon. Estimated yields approaching 2.05 bbl/ton of coal for high quality coal (carbon at approximately 85 wt %) can be demonstrated. Higher product yields remain to be demonstrated. A more detailed analysis of the process model is necessary in order to compare the heat and material balances for each major process step.

The DOE/NETL scheme is based on an iron catalyst system where a H_2/CO synthesis gas ratio can be well less than 1:1 which is significantly lower than that required for optimum F-T performance (2.1:1). Iron based catalysts offer the advantage of performing the water-gas shift reaction ($H_2O + CO \rightarrow H_2 + CO_2$) at the same conditions and within the same reactor vessel as the F-T synthesis. The principal downside to this catalyst system is the lower activity (typically 60 to 70% of that of a cobalt based catalyst on a comparable Syngas composition basis). The F-T reaction rate is depressed by the presence of high CO_2 levels (>15 vol %) and H_2/CO ratios well below the consumption value.

Comparison of the F-T reaction rates (catalyst productivities) is provided in a subsequent section.

The iron catalyst process (scheme 1) utilizes a quench heat boiler (radiant exchange boiler) to recover the sensible heat in the exit gas from the gasifier. This step is offered with the General Electric gasifers, and utilizes relatively high O_2 rates in the process flow scheme. Other process schemes utilize lower oxygen to carbon ratios. At this point, it is unclear if the heat integration associated with the ASU, Selexol and Claus facilities have been optimized with respect to capital cost and energy consumption. A potential option is to utilize a Rectisol unit (instead of Selexol) in order to remove the CO_2, mercury and reactive nitrogen compounds. Additionally, other reactive metals will be removed with this process. This option is discussed in the subsequent section. It is not clear if the Selexol process preferentially removes sulfur. The Coffeyville, Kansas facility utilizes Selexol for downstream production of hydrogen. Discussions with the Selexol vendor would be necessary to confirm the effluent stream (rich in H_2S) composition and the impact of further processing in a Claus facility.

The CO_2 removal step for the effluent F-T gas has been described as an amine acid gas removal process. Energy consumption for this process is significant. The aqueous organics recovered in the F-T products can be recycled to the gasifier or ATR as opposed to further product recovery and potential waste water treatment. Recycling of the light F-T naphtha offers the opportunity to improve diesel yields but further model evaluations should be conducted to determine the best split for meeting the tail (fuel) gas energy requirements. A separate economic analysis of the ATR recycle loop should be performed in order to determine the cost trade-off between the hydrogen and additional capital and energy costs.

The hydrogen recovery step assumes a relatively high mole fraction of this component in the F-T effluent gas It will be a challenge for most commercial F-T catalyst systems to produce these relatively high partial pressures of H_2. Most Fe catalyst systems tend to have a water-gas shift reaction that is slower than that of CO conversion via F-T. When operating at sub-stoichiometric ratios, it will be difficult to achieve the H_2 partial pressures with exit H_2/CO increasing from approximately 0.8:1 to 18.7:1.

In the upgrading steps (hydrotreating, hydroisomerization and hydrocracking), typical hydrogen consumption values are in the range of 600 to 800 standard cubic feed/barrel (scf/bbl), however iron catalysts (when operating at the proposed H_2/CO ratios) can produce a greater fraction of olefins leading to higher consumption values. The upgrading sequence typically utilized on F-T liquids involves a mild hydrotreating to convert olefins and oxygenates to paraffins, followed by hydro-isomerization. The hydrocracking steps for the very heavy hydrocarbons (C_20+) can be done in conjunction with the hydroisomerization or performed separately on the distilled cut. There are numerous technology vendors for this processing since the F-T liquids represent an ideal hydrocarbon fraction with respect to these types of chemistries.

B.3 Iron vs Cobalt Based Catalyst F-T Reactors B.3 of this annex compares the F-T reactors for iron and cobalt based slurry catalysts. In addition to the obvious catalyst parameters such as productivity and selectivity, there are other critical parameters unique to a slurry system. The attrition resistance of the catalyst is paramount in defining filterability (solids removal from liquid products) and hydrodynamic stability over extended operating periods. The deactivation rate is also very important since it defines the amount of catalyst trafficking through the reactor in order to maintain volumetric productivity. The filter and solids management systems for F-T slurry systems can be as expensive as the reactor itself, especially if the filter flux rates and other solid/liquid separations become a limiting production factor.

The F-T process literature contains several solid/liquid separation schemes which are strongly dependent upon catalyst properties. Detailed design will address the most appropriate method to achieve the highest product quality for commercial development. It is critical to develop support data for attrition, filtration and catalyst consumption parameters as well as performance reactor data showing the desired conversion and selectivity targets that match process performance with commercially available systems.

B.3.1 Gasifier and F-T Operations using 2:1 H_2/CO

The primary purpose of this section is to introduce a potential alternate processing scheme which may prove more commercially achievable due to the reduction in the F-T reactor size and simplicity in operations. The configuration is referred to as scheme II. This process configuration utilizes the same feed basis as scheme 1 with the following changes;

1. A water quench is employed instead of the quench heat exchanger.
2. Both high temperature and low temperature shift reactors are used to produce an F-T feed gas ratio near the anticipated consumption value of 2.1:1. Some heat recovery is performed between the shift reactors.
3. The F-T reactor operates as a once through system at 80% CO conversion. In all likelihood additional process modeling will show that a two F-T stage system will be more desirable to improve both product selectivity and overall carbon efficiency.
4. Product upgrading would consist of identical steps as that of scheme 1 (hydrotreating-hydroisomerization-hydrocracking). The hydrogen requirements would be obtained from a membrane unit operating upstream of the power recovery turbine where the partial pressure is the greatest.
5. There are two tail gas management units, the combustion system for heat recovery and fuel export to power facility.

Although further optimizations are required, this process scheme represents the basis for a commercial system which possesses full heat integration and requires no outside power utilities except for water treatment and startup. The absence of a quench heat exchanger simulates gasifer technology outside of General Electric and can be applied to suppliers who utilize a dry coal feed which possesses higher thermal efficiency as compared to coal slurry feed systems (Siemens or Shell).

Scheme II is the preferred configuration for a cobalt based slurry catalyst which possesses negligible shift activity relative to an iron catalyst. A similar synthesis gas is generated as in scheme 1. However, the worse case scenario of direct water quench is employed for Syngas cooling. The fraction of the quenched stream passes through a pair of shift reactors to make the hydrogen required for achieving a 2:1 H_2/CO. The potential advantage of this configuration involves the shift reactors cost compared to the incremental F-T reactor volume and partial cost of the CO_2 removal system in scheme 1.

The Rectisol clean up system is more expensive than the Selexol process; however it has the advantage of removing all catalyst contaminants including heavy metal, reactive nitrogen compounds, sulfur as well as CO_2. The HYSYS model details does not contain the full details of the system which includes two major towers (for primary absorption and H_2S recovery) and the multiple flash drums (approximately 4 to 7) which provide the bulk of the heat integration through use of the CO_2 flash. The cost of the Rectisol can be offset by the mercury absorption beds and partial savings of the scheme 1 CO_2 removal step and F-T reactor size. As in scheme 1, sulfur management must be considered and the Claus facility is the safe and sure method. It may be worthwhile to look at other alternatives. The hydrogen recovery system lies between the Rectisol system and the power recovery turbine. In this configuration, the hydrogen recovery cost will be less due to the higher source stream partial pressure.

The cobalt based catalyst F-T reactor system (more fully discussed and compared to an iron based catalyst system in the next section) will be significantly smaller than that of scheme 1. The effluent product water (containing very small quantities of oxygenates) can be recycled back to the gasifier regardless of the choice of the gasifer technology.

In summary, process scheme 2 presents the initial steps in the development of an alternate process configuration which may prove to be more cost effective compared to scheme 1. Both process schemes require further development with respect to heat integration and product optimization (especially scheme 2). Scheme 1 requires further work in securing F-T catalyst performance data and Selexol selectivity which meets the desired process requirements.

B.3.2 Overview of Iron and Cobalt based Catalyst F-T Reactor Systems

Scheme 1 presents the classical configuration for an iron based catalyst F-T system in which the sub stoichiometric synthesis gas is allowed to undergo both F-T and shift reactions simultaneously. The F-T reactor vessel must be sized to account for the residence time required for the relatively slow shift reaction. When operating at the same temperature, pressure and comparable Syngas ratio, iron based catalyst (either bulk or supported) have significantly lower productivities as compared to a cobalt catalyst (typically at least 40% lower). Decreasing the ratio into the range of 1:1 further depresses the iron catalyst productivity compared to a cobalt catalyst.

It is a well established fact that the kinetics of the F-T process is negative order in the CO partial pressure and at least first order in the partial pressure of hydrogen. In scheme 2, the H_2/CO ratio maintains a value slightly greater than 2:1 and a combined inlet partial pressure of approximately 240 psig decreasing to 66 psig at the outlet. In scheme 1, the inlet H_2/CO ratio is 0.81 at a total partial pressure of 259 psig and is anticipated to increase to 18.5:1. If this is indeed the case, one can expect a higher rate coupled with extremely light products possessing much lower than reported diesel and naphtha yields. Historically, the F-T based literature has shown that iron catalysts have much lower rates than cobalt based catalysts when operating at substoichiometric ratios requiring a significant amount of shift conversion.

The preliminary sizing of a F-T reactor can be done through an estimation of the amount of catalyst and basing the reactor volume using a 25% solids holdup. The reactor diameter is based on establishing a minimum gas velocity that will ensure churn turbulent mixing. The literature establishes this minimum velocity in the range of 10 cm/sec with higher velocities preferred. Decreasing the reactor diameter in order to increase the gas velocity results in an increase in the total reactor height. The diameter of the reactor is set so as to provide a minimum gas velocity to ensure a churn turbulent flow requiem to maximize heat and mass transfer between the phases. Preliminary estimates for the F-T reactor in scheme 1 would indicate a diameter of 20 ft in order to ensure an inlet gas velocity of approximately 13 cm/sec (near minimum value for hydrodynamic regime).

Assuming a catalyst productivity of 200 (volume of CO consumed per volume of catalyst per hour, v/v-hr), the required volume would correspond to a reactor height of approximately 175 ft of straight side. The assumed productivity is based on the CO conversion in both water-gas shift and F-T synthesis. Potential vendors may claim higher productivities (e.g. 400 v/v-hr) which would result in a proportional decrease in the reactor height. However it is unlikely that this productivity can be achieved at the desired product selectivity.

The scheme 2 configuration using a cobalt based catalyst with a productivity of 400 v/v-hr corresponds to a reactor with a 10 ft diameter operating at 24.5 cm/sec which is well into the desired churn turbulent range. The total reactor height would correspond to approximately 80 ft of straight side.

The cobalt catalyst system offers the potential to be far more attrition resistant than an iron catalyst due to the intrinsically higher activity of the cobalt metal which permits formulation on hard refractory supports (e.g. alumina or titania). Although improvements have been made in iron based catalysts, supported cobalt catalysts continue to be significantly more attrition resistance than bulk iron formulations. The combination of higher intrinsic activity, selectivity, attrition resistance and product selectivity (no water-gas shift activity) has lead to cobalt based catalysts being the catalyst of choice for the Sasol, Exxon-Mobil, Conoco Phillips, and Syntroleum slurry systems. Both Sasol and Rentech offer an iron catalyst but it is not clear that any significant potential advantages exist with this catalyst, other than the ability to operate at lower H_2/CO ratios.

Other potentially significant difference between iron and cobalt catalysts involves deactivation and regenerability. Iron catalyst systems are generally much less expensive in terms of cost per pound of fresh catalyst. However, this catalyst cannot be readily regenerated (due to sintering and loss of active catalyst area). Spent iron catalysts are typically sent off site for either metal reclaiming or disposal. Cobalt catalysts are more expensive but in many cases can be regenerated. The detailed design analysis will make a cost comparison involving the capital for regeneration and re-use versus once through and replaced. The deactivation rate is a critical parameter in this analysis. Cobalt systems that are regenerable and possess lower deactivation rates usually are more cost effective than once through iron catalyst. However, one should review the deactivation data of several vendors and utilize a solids management model which incorporates all of the above parameters in a detailed multi-year economic assessment.

B.4 Overview of Fixed Bed Systems The fixed bed reactor can be comparable in economic viability as the slurry for smaller F-T systems (<5000 bpd and possibly slightly larger). The scale-up of the fixed bed system is much more straight forward compared to the slurry since it involves the demonstration of a single tube scaled to multiple tubes in a well defined steam boiler system. The scale-up of slurry reactors involves several non-linear parameters associated with estimating productivities in combined plug flow/backmixed hydrodynamic regimes as well as attrition mechanisms for differently sized vessels.

Typically F-T fixed bed reactors are in the 1” to 1.5” range due to the high heat release and the poor internal heat transfer rates. The reactor systems are flow limited due to the combination of relatively low productivities (typically < 300 v/v-hr) and the pressure drop. Consequently, operation at sub stoichiometric Syngas ratios can lead to greater reactor volume requirements due to the volume of CO_2 (dilution impact on Syngas) associated with the shift reactor.

The most efficient fixed bed systems utilize a cobalt based catalyst operating at a 2:1 H_2/CO ratio. Shell utilizes this technology and also operates at sub stoichiometric ratios in order to increase the product yield of heavy paraffins at the expense of CO productivity. Another advantage of the fixed bed system is that catalyst regeneration can potentially occur in-situ, avoiding the cost and capital of transfer to external regeneration systems.

ANNEX C

STATEMENT OF JAY RATAFIA-BROWN

SENIOR ENGINEER

SCIENCE APPLICATIONS INTERNATIONAL CORPORATION

BEFORE THE UNITED STATES SENATE

COMMITTEE ON ENERGY AND NATURAL RESOURCES

MAY 24, 2007

Good Morning Mr. Chairman, Senator Domenici and Members of the Committee. Thank you for the opportunity to appear this morning to discuss the technical feasibility of co-converting coal and biomass to gaseous and liquid fuels via gasification and Fischer-Tropsch synthesis technologies. My testimony is based on over 30 years of broad experience conducting technical and environmental assessment and systems analysis for large-scale energy conversion methods, including recent project work.

Co-gasification of combined 'coal + biomass' feedstock is being advocated by researchers as a potential means of producing significant quantities of transportation fuels while yielding very low levels of pollutant discharges, as well reduced or near-zero release of carbon dioxide (CO_2), a greenhouse gas (GHG) forcing agent. To achieve these goals both rapidly and cost-effectively, this concept likely needs to utilize the technological strengths of large-scale, commercial coal gasification technology, which enables co-conversion of *renewable crop-based biomass* feedstock with coal, generation of suitably "clean" Syngas at required pressure/temperature conditions, and the capability to efficiently capture carbon dioxide (CO_2) for sequestration. Since the addition of biomass into a coal-based conversion system introduces unique technical requirements and challenges, my goal in this testimony is to discuss the potential for successfully engineering of such a hybrid energy conversion system.

DRIVERS FOR 'BIOMASS + COAL' CO-CONVERSION

The primary motivation for converting our substantial domestic coal and biomass resources to transportation fuels and chemicals is to displace the use of imported oil and, thereby, help mitigate its high price and supply security concerns. Inclusion of biomass in this endeavor also represents a potential means of reducing the environmental footprint of this transformation on a sustainable basis. In this regard, ambitious national and international goals, like *the U.S. Biomass Research and Development Act of 2000* and the *Biofuel Directive of the European Union*, call for large biomass-based energy conversion capacity in order to diversify the resource base for transportation fuels, chemicals, and power/heat generation. The ***U.S. Vision*** recommends that *biomass supply 5% of the nation's power, 20% of its transportation fuels, and 25% of its chemicals by 2030*. The ***EU Vision*** (as of March 2007) sets a goal of 10% biofuels use for transportation by 2020.

Key roadblocks to this resource conversion are associated with: 1) environmental consequences of greatly increasing coal consumption, particularly related to amplified release of greenhouse gas emissions (GHG); 2) small-scale, high specific-cost and relatively poor performance of available biomass conversion technologies; 3) availability of sufficient biomass feedstock (locally) for an economic plant size; and 4) shut-off risk or curtailment of operations if there is a biomass supply shortage or reduction in supply.

A very promising approach to resolution of most of these roadblocks is to combine conversion of coal and biomass in a large-scale facility that incorporates *gasification technology* to convert solid feedstock to Syngas (primarily H_2, CO, CO_2, H_2O, and CH_4); *Syngas processing* to remove unwanted contaminants such as sulfur, potassium, and mercury; *Fischer-Tropsch (F-T) synthesis technology* to convert Syngas to clean liquid fuels (naphtha and diesel); *carbon capture and storage (CCS)* technologies technology to allow efficient and safe sequestration of CO_2; and *power generation technology* to both supply internal requirements and electricity for sale. Individual plants would have to be very large to capture required economies-of-scale: **Transportation Sector ─** 25,000 to 50,000 bpd; and **Chemical Sector ─** 5,000 bpd equivalent. I will refer to this as the coal/biomass-to-liquids (CBTL) concept.

The environmental consequences of this approach, particularly as related to the net release of CO_2, have been investigated by researchers from the Princeton Environmental Institute.[43] Their findings indicate that a plant that combines co-gasification of biomass (switchgrass) and coal could potentially achieve a near-zero net CO_2 emission rate by exploiting the negative emissions of storing photosynthetic CO_2 in roots and soils. By comparison, the CO_2 emission rate for coal-only F-T liquids production, with CCS, could be reduced to about the same rate as crude oil-derived fuels. This approach could also require considerably less net biomass input to realize near-zero emissions than conventional biofuels conversion, such as cellulosic ethanol.

Let me summarize the key drivers for CBTL concept as I see them: **1**) Reduction of imported crude oil; **2**) Continued use of our abundant coal resources in an environmentally acceptable manner; **3**) Greater utilization of our abundant biomass resources in accordance with our national goals; **4**) Efficient and cost-effective utilization of biomass resources; **5**) Coal acts as a "flywheel" to keep a facility operating even if biomass is not sufficiently available; **6**) Within a strict carbon-constrained framework, such as McCain-Lieberman, this approach should become cost-effective, **7**) Use of reliable coal in concert with more environmentally acceptable renewable feedstock may reduce project financial risk for large-scale energy conversion plants; and **8**) Gasification-based projects could benefit significantly from the more positive public attitude displayed towards co-utilization of renewable feedstock, as well as development of a reliable multi-source fuel supply network for such projects.

Successful technical and cost-effective implementation of CBTL particularly depends on adoption of *suitable gasification technolog*y, addressing *biomass handling challenges*, satisfying *Syngas "cleanup" constraints*, and effectively *integrating CCS*. My intent in the remainder of this testimony is to focus on the challenges that each represent and their potential for enabling this concept to function effectively.

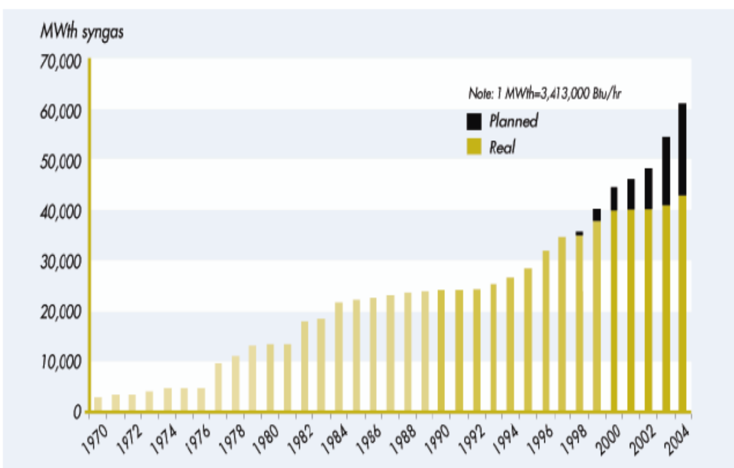
[43] Williams, R., "Synthetic Liquid Fuels From Coal + Biomass with Near-Zero GHG Emissions," Princeton Environmental Institute, Princeton University, January 12, 2005.

GASIFICATION TECHNOLOGY CAPABILITY AND EXPERIENCE

First, I want to convey that gasification technology is in widespread use today. The 2004 World Gasification Survey, sponsored by DOE, shows that in 2004 existing world gasification capacity had grown to 45,000 MWth of Syngas output at 117 operating plants with a total of 385 gasifiers. Coal (49% of capacity), petroleum products (37%) and natural gas (9%) currently dominate the gasification market as the primary feedstocks for production of F-T liquids, chemicals, and power. Note, however, that biomass gasification only accounts for about 2% of the total Syngas production. Figure 1 presents a summary of large-scale gasification experience.

The gasification technology represents the most critical component that impacts system design and operation of a CBTL facility. The desirable design characteristics for co-gasification technology for F-T liquids applications (using high rank coals) are: *large individual gasifier throughput* (>1000 MWth); *high temperature* (> 2,300^{o} F to eliminate tars/oil contaminants in the Syngas); *high pressure* to increase Syngas throughput and reduce process component sizes; *oxygen-blown* (as opposed to air-blown) to eliminate nitrogen as a Syngas diluent; *slagging* (a consequence of high temperature operation) to render most of the feedstock ash as a benign byproduct for utilization purposes; *dry feed* of biomass since it is difficult to handle as a slurry, and use of a relatively *large particle size* to reduce feedstock preparation.

Exhibit 1. Summary of Large-Scale Gasification Experience
(2004 DOE World Gasification Survey)



Worldwide gasification capacity is increasing by 3 GW_{th} per year and will reach 61 GW_{th} in 2004

- **In 2004**
- By activity:
- 24 GW_{th} chemicals
- 23 GW_{th} power
- 14 GW_{th} synfuels
- By region:
- 9 GW_{th} China
- 10 GW_{th} N America
- 19 GW_{th} W Europe
- 23 GW_{th} Rest of world

By feedstock:
- 27 GW_{th} petroleum residuals
- 27 GW_{th} coal
- 6 GW_{th} natural gas
- 1 GW_{th} biomass

Fortunately, these design characteristics are generally met with the widely used *entrained-flow gasification* technology, which currently dominates the large-scale gasification market with 85% of the installed units. (Note that this technology also continues to benefit from a variety of related R&D efforts sponsored by DOE to further improve performance and cost, including development of a compact transport-type gasifier technology.) While these gasifiers are quite flexible with regard to feedstock characteristics, their high reaction rates demand very small feedstock input size (e.g., < 100 micron or 0.004 inches) that is easily achievable for friable materials like coal, but more challenging and energy-consuming for biomass feedstock. Compounding this important issue is the high pressure injection requirement for the entrained-flow technology, which may present a challenge to biomass injection into the gasifier. Also, the chemical make-up of biomass ash will cause it to behave differently that coal ash, which must be accounted for in design and operation. Several large-scale demonstrations of entrained-flow co-gasification of coal and biomass have already been performed here and in Europe.

Commercial scale co-gasification of biomass with coal has been demonstrated at the 253 MWe Nuon IGCC power plant in Buggenum, The Netherlands (using the dry-feed Shell entrained-flow technology), as well as at Tampa Electric's 250 MWe Polk IGCC power plant (using GE entrained-flow technology). (The latter was built in the 1990s as part DOE's Clean Coal Demonstration Program.) The Nuon plant recently tested biomass content up to 30% by weight (17% of total energy input), which requires up to 205,000 tons/year of biomass feedstock and coal feed is about 435,000 tons/year. Besides gasification of *demolition wood*, tests were also conducted with *chicken litter* and *sewage sludge*. The co-gasification tests conducted at the Polk plant used up to 1.5% by weight of woody biomass harvested from a 5-year-old, locally-grown Eucalyptus grove. Since the plant uses 2,200 tons/day of coal, the biomass co-gasification basis was 33 tons/day (about 10,000 tons/yr).

Not only did these plants operate normally, but we can generally conclude that biomass feed size can be on the order of 1 mm (0.04 inches) due to biomass' high reactivity relative to coal. The importance of this lies in the capability to minimize biomass milling power consumption and possibly avoid other efficiency-reducing pre-treatment processes. The Nuon experience has also shown that a relatively high throughput of biomass is possible in an entrained-flow unit that is co-gasifying coal. Pilot-scale tests were also tests were also conducted at the National Energy Technology Laboratory (NETL)/Morgantown some years ago with coal and up to 35% biomass.

COAL+BIOMAS CO-GASIFICATION CHALLENGES

Below, I provide a brief overview on key challenges associated with oxygen-blown, entrained-flow gasification of coal and biomass.

Oxygen feed to the gasifier – standard cryogenic method of oxygen production is both costly and energy intensive; however, DOE is well into development of so-called ion transport membrane (ITM) technology, which promises significant cost reductions and efficiency gains.

Biomass and coal injection – Feedstock injection into high pressure gasifiers is challenging. Conventional dry-feed methods employ a series of complex lock hoppers. Due to the low energy density of biomass, lock hoppers have two major disadvantages: (1) large amounts of inert gas are required and must be compressed, and (2) gasification efficiencies drop due to the dilution of the Syngas. Fortunately, DOE's gasification program has been developing a rotary dry-feed coal pump that, when fully tested, should allow the feedstock to be "pushed" directly into the gasifier.

Biomass particle size – While entrained-flow gasifiers require very small coal particle sizes (< 0.004 inches), recent commercial 'coal + biomass' tests suggest a much larger size (0.04 inches) is likely feasible due to the high reactivity of biomass due to its high O_2 and volatiles content

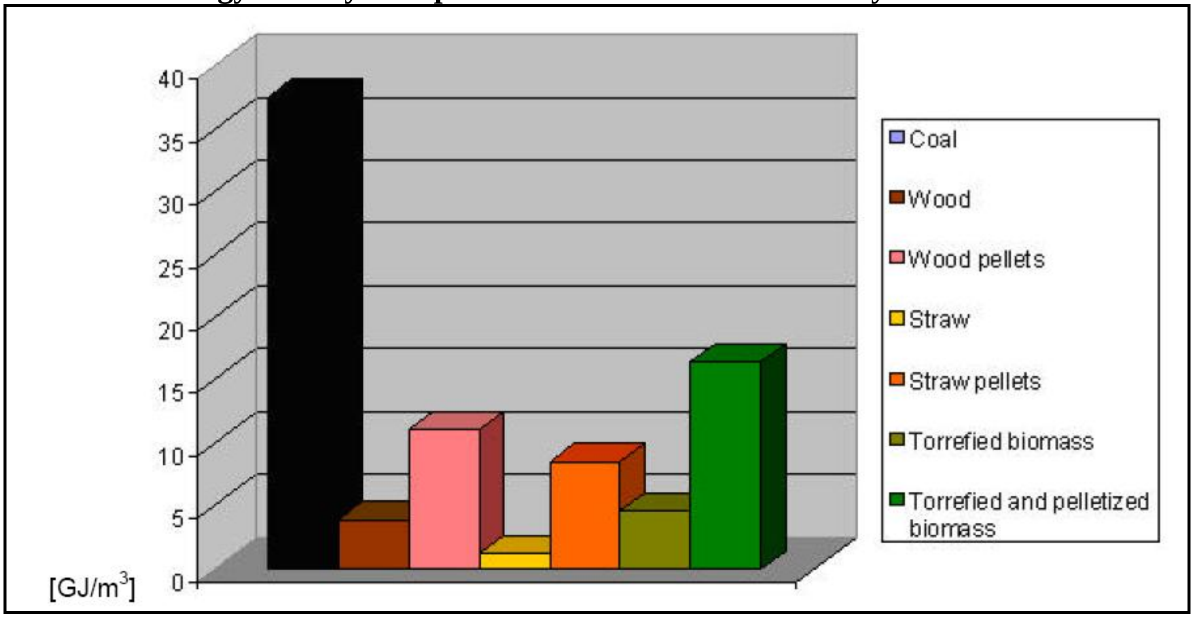
Biomass ash slagging behavior – While the slagging performance of the biomass ash may be an issue, testing has shown that "flux" material (aluminum-silicates) can be added to the gasifier to re-establish acceptable ash slagging performance.

The bottom-line is that the practical limit of biomass co-processing with high rank coals (bituminous and subbituminous coals) is probably associated more with biomass preparation and feed issues and desired Syngas production level, than the capabilities of the entrained-flow gasification process.

BIOMASS HANDLING CHALLENGES

Our work has primarily focused on crop-based biomass, particularly prairie grass/switchgrass and short rotation woody crops (SRWC), such as Poplar and Eucalyptus. These are defined as fast-growing, genetically improved trees and grasses grown under sustainable conditions for harvest at 1 to 10 years of age. In general, their biomass heating values [MJ/kg] and particle densities are about half of that of coal, whereas bulk raw densities [kg/m^3] are about 20% of that of coal, resulting in overall biomass energy density [MJ/m^3] approximately 10% of coal (see Exhibit 2). As a consequence, when co-gasifying raw biomass at a 10% heat input rate with coal, the volume of coal and biomass can actually be similar; therefore, *biomass requirements with regard to transport, storage and handling are very high in comparison to its heat contribution.*

Exhibit 2. Energy Density Comparison of Different Biomass Physical Forms with Coal



Biomass either has to be located very close to a conversion facility and processed immediately, or some form of "densification" needs to be implemented to mitigate handling issues. Since this is a well-recognized issue for biomass, especially for conversion processes that can consume very large quantities, a number of methods have been developed, albeit currently at small-scale, that are applicable. These are *pelletization*, which is a drying/compression method that increases energy density of switchgrass pellets by a factor of eight. *Torrefaction* is a "roasting" treatment that operates within a temperature range of 200 to 300 °C and is carried out under atmospheric conditions in the absence of oxygen. This process not only increases the energy density of wood by about 25%, but also greatly reduces the milling energy consumption to reduce size. Combined torrefaction and pelletization can increase the energy density of wood by about five times. *Pyrolysis* is an option to produce a liquid product (pyrolysis oil) from biomass, via its thermal decomposition, at temperatures of 450-550° C. Yield efficiency of pyrolysis oil production averages about 70%, and volumetric energy content of pyrolysis oil is 19 68,300 Btu/gal compared with # 6 Oil at 144,000 Btu/gal.

SYNGAS "CLEANUP" CONSTRAINTS

The CBTL concept requires strict limits on various contaminants in the Syngas, most of which come from coal, but biomass co-contributes certain elements and related compounds such as calcium (Ca), phosphorous (P), chlorine (Cl), sodium (Na) and potassium (K). The limits are intended to prevent poisoning of the F-T catalysts and fouling/corrosion of downstream system components, such as heat exchangers and gas turbine blades. As an example, constraints on alkali metals (Na + K) are less than 10 parts per billion by volume (ppbv) and halides (HCL + HBr + HF) are also less than 10 ppbv. These and other limits are controlled via the integration of a group of processes that sequentially treat the Syngas once it exits the gasifier. These include dry particulate removal, wet Syngas scrubbing for fine particulate and gases, mercury removal, and acid gas (H_2S and CO_2) removal. Experience with commercial IGCC power plants, such as the Polk IGCC plant and the Wabash River plant (another DOE Clean Coal Technology Program investment), as well as refinery gasifiers, have established that the CBTL Syngas limits can be met with appropriate system design.

CARBON CAPTURE AND STORAGE CHALLENGE

Operation of a CBTL facility will reduce CO_2 emissions relative to a more conventional Coal-To-Liquids (CTL) design, even without integration of CCS technology. The extent of the reduction depends on the relative level of biomass energy input. For example, the 30% (by weight) biomass feed to the Nuon plant that I discussed previously, resulted in an effective CO_2 reduction of about 17% or 220,000 tons/yr (excluding GHG emissions related to biomass collection and treatment). On the other hand, integration of CCS technology will reduce the GHG footprint of CBTL to a much greater extent. However, while CO_2 capture technology is commercially available and well-proven for gasification-type applications, it increases capital expenditure and operating costs; DOE is currently developing advanced membrane technologies to lower this impact. More importantly, the actual sequestration of CO_2 is far from commercially available and acceptable. As stated by DOE, key challenges are to demonstrate the ability to store CO_2 in underground geologic formations with long-term stability (permanence), to develop the ability to monitor and verify the fate of CO_2, and to gain public and regulatory acceptance. DOE's seven Regional Carbon Sequestration Partnerships are engaged in an effort to develop and validate CCS technology in different geologies across the Nation. This is vital to sequestration's future and use with the CBTL technology.

CONCLUSION

Even without considering currently favorable government programs to encourage investment in CTL and CBTL technology, I've endeavored to convey that that there are considerable drivers that strongly support continued development. *Importantly, it takes advantage of the significant investment and progress that the country has made with gasification and related technologies over the past twenty-five years.* Commercial entrained-flow gasification technology has been proven to be capable of co-gasifying coal and biomass, which at the minimum would permit reduced GHG emissions from future CTL facilities. Incorporation of CCS technology, when sequestration is technically available and appropriate to regulatory conditions, can have a major impact on the sustained use of our abundant coal resources and greater use of our biomass resources. Although, I've reported on some successful tests of coal and biomass co-gasification, I've also attempted to convey that R&D is needed to deal with significant challenges related to biomass handling and feeding issues that are important to plant operability and cost-effectiveness. Also, longer-term, large-scale tests of the CBTL concept are required to better understand how a well-integrated design will perform and function. Overall, I strongly believe this is a technology that has great potential to improve our energy security while also being a good steward of the environment.

I will be happy to answer any questions.

Annex D: Detailed Conceptual Cost Summary

									Report Date:	29-Feb-08
	Project:	Indiana Clean Energy Project - Fischer Tropsch & Power Plant								
	Plant Size:	25.089	MW,net		Estimate Type:	Conceptual				$ x 1,000
		6,099	FT Liquids bbl/day							
Acct		Equipment	Material	Labor		Bare Erected	Eng'g CM	Contingencies		TOT. PLANT
No.	Item/Description	Cost	Cost	Direct	Indirect	Cost $	H.O. & Fee	Process	Project	COST $
1	**Coal & Sorbent Handling**	6,892	1,324	5,546	388	14,151	1,132		3,821	19,104
2	**Coal-Water Slurry Prep & Feed**	10,641	2,161	8,168	572	21,542	1,723		5,816	29,081
3	**Feedwater & Misc Bop Systems**	2,061	1,794	2,011	141	6,006	480		1,622	8,108
4	**Gasifier & Accessories**									
4.1	Gasifier & Auxiliaries	56,644	24,892	43,498	3,045	128,079	10,246	14,161	38,405	190,891
4.2	Syngas Cooling	w/4.1								
4.3	Asu/Oxidant Compression	54,264		w/equip.		54,264	4,341	13,566	18,314	90,485
4.4-4.9	Other Gasification Equipment	9,797	11,249	12,708	889	34,643	2,771	4,899	10,676	52,989
	Subtotal 4	120,705	36,141	56,206	3,934	216,987	17,358		67,395	334,365
5A	**Gas Cleanup**	27,199	3,341	26,555	1,859	58,955	4,716	13,600	19,590	96,860
5b	**Fischer-Tropsch Systems**	46,908	5,160	9,382	657	62,106	4,968	40,223	27,193	134,490
6	**Combustion Turbine Generator**									
6.1	Combustion Turbine Generator	32,031	0	1,047	74	33,152	2,652		8,951	44,755
6.2-6.9	Combustion Turbine/Generator Accessories	0	171	150	12	333	27		90	450
	Subtotal 6	32,031	171	1,197	86	33,485	2,679		9,041	45,205
7	**Hrsg, Ducting & Stack**									
7.1	Heat Recovery Steam Generator	3,191	0	362	26	3,579	286		966	4,831
7.2-7.9	Hrsg Accessories Ductwork And Stack	309	195	231	16	752	60		203	1,015
	Subtotal 7	3,501	195	593	42	4,331	346		1,169	5,846
8	**Steam Turbine Generator**									
8.1	Steam Tg & Accessories	10,947	0	1,356	95	12,398	992		3,347	16,737
8.2-8.9	Turbine Plant Auxiliaries & Steam Piping	4,498	268	2,224	156	7,146	572		1,930	9,648
	Subtotal 8	15,445	268	3,581	251	19,544	1,564		5,277	26,385
9	**Cooling Water System**	2,277	1,420	1,999	140	5,837	467		1,576	7,880
10	**Ash/Spent Sorbent Handling Sys**	7,733	4,329	7,318	513	19,893	1,591		5,371	26,855
11	**Accessory Electric Plant**	2,004	892	2,255	158	5,309	425		1,433	7,167
12	**Instrumentation & Control**	3,102	469	2,327	163	6,061	485		1,636	8,182
13	**Improvements To Site**	1,431	844	3,159	221	5,654	452		1,527	7,633
14	**Buildings & Structures**	0	1,826	2,961	207	4,994	400		1,348	6,742
15	**2.0 Mile Heavy Rail Track**	237	2,693	1,239	87	4,255	340		1,149	5,744
16	**7 Mile PVC Water Main f/Lake, 1,000 GPM**	60	2,210	639	48	2,957	237		798	3,992
17	**Power transmition to Grid**									
17.1	Main power Transformers	1,325	550	120	10	2,005	160		541	2,706
17.2	Substation and Relay Equipment	453	286	338	23	1,100	88		297	1,485
	Subtotal 17	1,778	836	458	33	3,105	248		838	4,191
18	**Fuel Storage and Transfer**	25	162	44	3	234	19		63	316
	TOTAL COST	$284,032	$66,235	$135,638	$9,500	$495,404	$39,630	$86,448	$156,663	$778,145