SB 228

SENATE COMMITTEE REPORT
First Committee of Referral

DATE: 1/19/10 FURTHER: Finance

Date of 5-Day Notice: _____
(in accordance with Uniform Rule 23)

DATE TURNED
IN TO OFFICE: _____

Resources Committee considered SENATE BILL NO. 228

SB 228 TAX INCENTIVES FOR GAS-TO-LIQUID

"An Act providing for an industrial incentive investment tax credit and including a gas- to-liquids facility as an eligible investment; and providing for a production tax limit on gas used as a raw material for producing liquids or petrochemicals from gas in the state."

and recommends:

[ ] be **replaced** with [ ] **SCS** or [✓] **CS** SB 228 (RES)

[ ] adopt **previous** [ ] **SCS** or [ ] **CS** _____ (_____)

[ ] attached amendment(s)

[ ] adopt _____Letter of Intent

[ ] further referral to _____Committee

SENATE BILL:
[ ] Same Title
[✓] New Title

HOUSE BILL:
[ ] Same Title
[ ] Technical Title Change
[ ] New Title w/ SCR #_____

NEW FISCAL NOTE(S):

Department	Date	Fiscal	Indet.	Zero	FN#
REV	02/06		✓		

PREVIOUS FISCAL NOTE(S):

Department	Date	Fiscal	Indet.	Zero	FN#

[ ] **APPROPRIATION - no fiscal note**

SIGNATURES AND RECOMMENDATIONS:	PRINTED LAST NAME	DO PASS	DO NOT PASS	NO REC	AMEND
	Huggins			✓	
	Stevens			✗	
					✓
	French			✓	
CO-CHAIR:	McGuire	✓			
CO-CHAIR:	Wielechowski	✓			

CS FOR SENATE BILL NO. 287(RES)

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-SIXTH LEGISLATURE - SECOND SESSION

BY THE SENATE RESOURCES COMMITTEE

Offered:
Referred:

Sponsor(s): SENATORS MCGUIRE, Davis

A BILL

FOR AN ACT ENTITLED

"An Act amending the powers and duties of the Alaska Railroad Corporation related to the exercise of authority to purchase, transport, and sell natural gas produced on the North Slope for in-state use, and transferring exclusive and primary responsibility for the initiation and development of that project to that corporation; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

*** Section 1.** The uncodified law of the State of Alaska is amended by adding a new section to read:

LEGISLATIVE FINDINGS AND PURPOSE. (a) The legislature finds that

(1) by 2018, declining oil flow through the Trans Alaska Pipeline System will seriously diminish state revenue;

(2) Cook Inlet natural gas reserves are depleting at a rate that could cause significant short-term shortages for residential and commercial gas users in Southcentral

Alaska by 2013;

(3) a proposed natural gas pipeline to deliver North Slope gas reserves to the North American domestic gas pipeline grid at a connection in central Alberta will not produce revenue for the benefit of the state before 2020;

(4) the state's significant reserves of natural gas should be made available on a priority basis in the state to enhance employment opportunities, expand the state's economy, and supply a significant portion of community energy needs;

(5) the Alaska Natural Gas Development Authority is studying a pipeline spur, aggregating in-state demand for natural gas, and facilitating delivery of natural gas and natural gas liquids to Alaskans; and

(6) in light of competing demands for future uses of the state's North Slope natural gas reserves, an aggressive effort involving planning, permitting, and coordination of information sharing, of necessary agreements and commitments, and commercial negotiations among interested parties is necessary for completion of construction of an in-state natural gas pipeline that will provide significant direct benefit to the people of the state at the earliest possible date.

(b) It is the purpose of this Act

(1) to give general direction to the Alaska Railroad Corporation, an agency that enjoys express authority to acquire, construct, improve, maintain, equip, and operate a natural gas pipeline and related facilities for the transportation of natural gas recovered from the North Slope without regard to whether the facilities are or will be owned in whole or in part by the corporation or located on land owned by the corporation, to plan and develop construction of a high pressure in-state natural gas pipeline of appropriate diameter between Alaska's North Slope and Cook Inlet sufficient to provide for the distribution of natural gas for residential and commercial purposes at locations along the pipeline route; and

(2) to advance to the point of project sanction an in-state natural gas pipeline that will provide significant direct benefit to the people of the state at the earliest possible date.

*** Sec. 2.** AS 42.40.460 is amended by adding a new subsection to read:

(l) The provisions of AS 42.40.560(d) prevail over the provisions of this section for the purpose of development of the North Slope natural gas pipeline project

described in that section.

* **Sec. 3.** AS 42.40.560 is amended to read:

Sec. 42.40.560. North Slope natural gas pipeline. The corporation may provide [FINANCING] for the acquisition, construction, improvement, maintenance, equipping, and operation of a natural gas pipeline and related facilities**, and for the financing of the pipeline project and related facilities,** for the transportation of natural gas recovered from the North Slope of this state without regard to whether the facilities are or will be owned in whole or in part by the corporation or located on land owned by the corporation. **The authority provided by this section is limited to the project popularly identified as the Stand-Alone Pipeline Project, or Stand-Alone Project, that**

(1) proposes to develop a gas pipeline system to transport natural gas, and possibly additional natural gas liquids to markets in the Anchorage bowl area, and the Kenai Peninsula, and to additional customers along the transportation route;

(2) contemplates the commercial development of two primary sources of natural gas, the Prudhoe Bay Central Gas Facility and the Gubik gas field located in the northern foothills of the Brooks Range, and allows for use of gas from either or both of those gas sources or from any other source of natural gas;

(3) projects a pipeline system routing generally along the state's existing transportation corridors between the North Slope and Southcentral Alaska, starting from each potential gas source location, making its way to the Trans Alaska Pipeline System and Dalton Highway corridor, generally paralleling that corridor from the North Slope to the vicinity of Livengood, north of Fairbanks, and continuing to the Cook Inlet area, using one of two routes that are the existing transportation corridors between Fairbanks and Cook Inlet: the Parks Highway and the Richardson and Glenn Highways; and

(4) is compatible but not competitive with the project described in and authorized by AS 41.41 or the project described in and authorized by AS 43.90.

* **Sec. 4.** AS 42.40.560 is amended by adding new subsections to read:

(b) In the exercise of its authority under (a) of this section for a North Slope natural gas pipeline project, the corporation shall

(1) establish, maintain, and operate a subsidiary of the corporation to perform the work described in this section;

(2) aggressively pursue the acquisition of all necessary federal permits and authorizations essential for the development and operation of the project;

(3) provide monthly reports to the presiding officers of each house of the legislature and to the governor on the corporation's activities relating to the project;

(4) initiate a cost study for construction of a gas-to-liquids facility; in the exercise of its authority under this paragraph, the corporation may arrange for essential engineering and design work; and

(5) initiate efforts to identify and develop in-state markets for the natural gas to be delivered by the project and, to the extent necessary to ensure the long-term feasibility of the project, work to identify and develop overseas markets for the gas.

(c) Subject to AS 36.30.015(e), the board may provide that all or any portion of the project described in this section shall be subject to competitive sealed bid or competitive sealed proposal procedures.

(d) To fulfill its obligations under this section, the corporation shall identify all or a portion of a proposed natural gas pipeline transportation corridor:

(1) to the maximum extent possible consistent with ensuring the long-term feasibility of the project, the corporation shall make reasonable efforts to locate the proposed corridor between Fairbanks and the Kenai Peninsula on its land;

(2) notwithstanding any contrary provision of law, the Department of Natural Resources shall grant the corporation a right-of-way lease under AS 38.35 for the transportation corridor identified under (1) of this subsection if

(A) the corporation submits a complete right-of-way lease application under AS 38.35.050;

(B) the lease application is made the subject of notice and other

reasonable and appropriate publication requirements under AS 38.35.070; and

(C) the corporation agrees to be bound by the right-of-way lease covenants set out in AS 38.35.120;

(3) notwithstanding any contrary provision of law, a right-of-way lease granted under (2) of this subsection is subject to AS 38.05, except that the best interest findings requirements of AS 38.05 do not apply to a lease made under this subsection.

*** Sec. 5.** The uncodified law of the State of Alaska is amended by adding a new section to read:

ALASKA RAILROAD CORPORATION: TRANSITIONAL PROVISIONS AFFECTING OBLIGATIONS UNDER AS 42.40.560. (a) Subject to (c) of this section, in discharging its obligations under AS 42.40.560(b)(2), enacted by sec. 4 of this Act, the Alaska Railroad Corporation shall

(1) initiate permit and acquisition applications in accordance with the federal permit schedule that was provided to the legislature by the Office of the Governor on or about December 15, 2009;

(2) seek letters of intent from buyers and sellers of natural gas to ship gas using the facilities of the project and, from information obtained, by February 15, 2011, define the project parameters that would allow the project to be commercially viable;

(3) seek letters of interest from private pipeline construction and operating companies to develop the project; the work under this paragraph should be initiated between November 15, 2010, and shall be completed by March 15, 2011;

(4) prepare and submit to the governor and the presiding officer of each house of the legislature, by December 15, 2010, any initial legislation necessary to advance the project;

(5) identify or define and submit to the legislature, not later than January 15, 2011, the corporation's estimates of any long-lead time cost items or work tasks to achieve an early start-up for the project;

(6) prepare a final bankable feasibility document; the work under this paragraph should be initiated by July 1, 2011, and shall be completed by June 30, 2012; and

(7) unless otherwise provided in the monthly report required by AS 42.40.560(b)(3), enacted by sec. 4 of this Act, prepare and submit a report at each of the

dates set out in (1) - (6) of this subsection to the governor, the speaker of the house of representatives, and the president of the senate.

(b) The parties having responsibility for contracts, permit and acquisition applications, and studies in progress on the effective date of this Act entered into by the Office of the Governor or a state agency shall transfer those obligations and initiatives to the Alaska Railroad Corporation. Transfer of those obligations and initiatives may not be unreasonably delayed.

(c) The corporation shall cease its activities under this section and AS 42.40.560, as amended by secs. 3 and 4 of this Act, if the corporation receives a communication that

(1) the governor, after setting out with particularity the reasons that support the decision, has entered a finding that

(A) an agreement has been entered into that will result in construction of the project described in AS 43.90;

(B) construction of the project described in this section would prevent initiation and completion of the project described in AS 43.90; or

(C) other circumstances warrant cessation of activities under this section and AS 42.40.560;

(2) the legislature expresses its approval of the finding of the governor made under (1) of this subsection by concurrent resolution.

*** Sec. 6.** This Act takes effect July 1, 2010.

ADOPTED
03/18/10

26-LS1324\P
Bullock
3/17/10

CS FOR SENATE BILL NO. 228( )

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-SIXTH LEGISLATURE - SECOND SESSION

BY

Offered:
Referred:

Sponsor(s): SENATORS MCGUIRE, Wielechowski, Ellis

A BILL

FOR AN ACT ENTITLED

"An Act providing for a tax credit for investment in a facility that produces liquids from gas, coal, or biomass; and providing for a production tax limit on gas used in the state as a raw material for producing liquids or petrochemicals from gas."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

*** Section 1.** AS 43.20 is amended by adding a new section to article 1 to read:

Sec. 43.20.046. Special investment tax credit to produce liquids from gas, coal, or biomass. (a) Subject to (b) of this section, for purposes of calculating eligible taxes, the taxpayer may apply as a credit against eligible taxes the following percentage on only the first $1,000,000,000 of investment in the state for each taxable year after December 31, 2010, for a facility that produces liquids from gas, coal, or biomass: (1) 100 percent on the first $50,000,000 of investment; (2) 80 percent on investment over $50,000,000 but not exceeding $100,000,000; (3) 70 percent on investment over $100,000,000 but not exceeding $150,000,000; (4) 60 percent on investment over $150,000,000 but not exceeding $200,000,000; and (5) 40 percent on

investment over $200,000,000 but not exceeding $1,000,000,000. A credit may not be allowed under this subsection for leased property. The credit under this subsection may not exceed $475,000,000 for a single facility.

(b) A taxpayer may not claim an investment tax credit under (a) of this section unless the facility that produces liquids from gas, coal, or biomass or the mining project began operation and production after December 31, 2010. A facility for producing liquids from gas, coal, or biomass or a mining project is considered to have begun operation and production when the first liquids from gas, coal, or biomass or the first minerals are produced that are ultimately either sold or transferred for further processing or ultimate use.

(c) The investment tax credit for a taxable year allowed by (a) of this section may not exceed 60 percent of the eligible tax liability. Any unused portion of the investment tax credit may be carried forward.

(d) A tax credit under this section may not be claimed for investments made after December 31, 2020.

(e) In this section,

(1) "biomass" has the meaning given in 26 U.S.C. 45K(c)(3) (Internal Revenue Code);

(2) "facility for producing liquids" means the integrated plant, facilities, and equipment used for producing liquids from natural gas, coal, or biomass;

(3) "liquids" means a product stream of commercial quality that is a mixture of hydrocarbon molecules, each of which has between five and 20 carbon atoms with attached hydrogen atoms, none of which contain oxygen or other elements.

*** Sec. 2.** AS 43.55.900(24) is amended to read:

(24) "used in the state" means delivered for consumption as fuel in the state, including as fuel consumed to generate electricity **or used as fuel or feedstock in a manufacturing process creating an end product in the state, regardless of the final disposition of the manufactured end product**.

*** Sec. 3.** AS 43.55.900 is amended by adding a new paragraph to read:

(25) "manufacturing process" means the process of forming a valuable compound by chemically converting gas or components of gas or chemically

combining gas or components of gas with other substances; "manufacturing process" does not include gas processing, gas treatment, dehydration, fractionation, compression, or liquefaction.

ALASKA STATE LEGISLATURE

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Senate Committee on World Trade, Technology and Innovations

Co-Chair
Senate Resources Committee

Member
Senate Judiciary Committee

SENATOR LESIL MCGUIRE

Summary of Changes to SB 228 in CSSB 228, Version 26-LS1324\S

The following changes were made to SB 228 (26-LS1324\R) *Tax Incentives for Gas to Liquids* in order to include coal-to-liquids or biomass-to-liquids in the list of eligible facilities for the proposed investment tax credit as originally intended by the sponsor, and to correct an error in the original version related to provisions in the federal income tax code.

Changes to Section 1:

From: (26-LS1324\R) Section 1: Page 1, line 11-12: "for a gas-to-liquids facility:"

To: (26-LS1324\S) Section 1: Page 1, line 10-11: "for a **facility that produces liquids from gas, coal or biomass**:"

In the version of SB 228 that was introduced (26-LS1324\R), a facility had to be a "gas-to-liquids" facility in order to qualify for the proposed credits. While either coal (CTL) or biomass (BTL) must first be converted to a synthetic gas before they can be converted to a liquid, Legislative Legal Services recommended expanded language to ensure that a CTL/BTL facility qualified as the sponsor originally intended.

Changes to Section 1-6

Sections 1-6 have been consolidated into a single section in the S version and established as a separate "Special industrial incentive tax credit" under a new section in AS 43.20; the Alaska Net Income Tax Act. The change was made because of the linkage to 26 U.S.C 38 (Internal Revenue Code) in section 1 of the R version. 26 U.S.C. 38 was changed and the proposed facilities would not qualify under the current federal code.

Since the State adopts by reference the federal code in Alaska's Net Income Tax Act, the creation of a separate section was necessary in order to provide the desired incentive. It is important to note that as currently drafted, the S version provides a substantially greater credit than originally proposed in the R version. Separate provisions of Article 20 limit deductions to 18% of any federal credit. As drafted, the S version does not contain this limit.

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Joint Armed Services Committee

Senator.Lesil.McGuire@legis.state.ak.us

Sponsor Statement for Senate Bill 228: Tax Incentives for Gas-to-Liquids

Fischer-Tropsch is a chemical process through which synthesized gas is converted into a liquid hydrocarbon. The liquid hydrocarbons created through a Fischer-Tropsch process are a synthetic crude oil or synthetic diesel fuel that are both significantly cleaner burning than traditional oil or even ultra-low sulfur diesel, and command a premium in the market. The synthesized gas required by the process can be created from a wide variety of resources, ranging from wood and biomass to coal or natural gas. The technology is therefore often described as either a: BTL (biomass-to-liquids), CTL (coal-to-liquids), GTL (gas-to-liquids) or XTL ("X" resource-to-liquids) process.

Alaska has prolific coal, biomass and natural gas reserves that could provide the resources necessary for a robust XTL industry. When coupled with the growth in worldwide demand for the cleaner synthetic crude oils and clean diesels created through the Fischer-Tropsch processes, XTL technology presents an important opportunity for Alaska. XTL is a value-added, labor intensive process that can provide thousands of high-paying jobs in the State.

However, XTL facilities are capital intensive investments that often require billions of dollars and hundreds of thousands of man hours to construct. This is why Senate Bill 228 provides a corporate income tax credit for the construction of an XTL facility in Alaska. SB 228 allows a company to claim a credit against their future corporate income taxes based on a declining percentage of the first billion dollars of investment they make in Alaska. The amount of tax credits they may claim in any given year is limited to 60% of their tax liability, which ensures Alaska will have the revenue to provide this incentive.

SB 228 also clarifies that gas used in Alaska for value added industries like GTLs or petrochemicals receives the same tax treatment as gas used to generate electricity or heat Alaskans homes.

South Africa has been producing diesel from coal and natural gas for generations. Through XTL technology they have created an extensive value-added industry that is a foundation for their economy. The purpose of SB 228 is to open Alaska to these promising technologies and attract the investment necessary to establish a vibrant, value-added economy in Alaska.

LEGAL SERVICES

DIVISION OF LEGAL AND RESEARCH SERVICES
LEGISLATIVE AFFAIRS AGENCY
STATE OF ALASKA

(907) 465-3867 or 465-2450
FAX (907) 465-2029
Mail Stop 3101

State Capitol
Juneau, Alaska 99801-1182
Deliveries to: 129 6th St., Rm. 329

MEMORANDUM January 28, 2010

SUBJECT: Sectional Summary for SB 228 (Work Order No. 26-LS1324\R)

TO: Senator Lesil McGuire
Attn: Mike Pawlowski

FROM: Donald M. Bullock Jr.
Legislative Counsel

You have requested a sectional summary of the above-described bill.

As a preliminary matter, note that a sectional summary of a bill should not be considered an authoritative interpretation of the bill and the bill itself is the best statement of its contents. If you would like an interpretation of the bill as it may apply to a particular set of circumstances, please advise.

Section 1. Amends AS 43.20.042(a) to authorize a tax credit on the first $1,000,000 of qualified investment during a taxable year for a gas-to-liquids facility. The credit is applicable to investments made after December 31, 2010.

Section 2. Amends AS 43.20.042(b) to increase the amount of qualified investment for exploration, drilling of wells, development, or mining of certain minerals and other natural deposits that is eligible for a tax credit, to $1,000,000 for each taxable year. The credit is applicable to investments made after December 31, 2010.

Section 3. Amends AS 4320.042(c) to make the credits in secs. 1 and 2 only applicable to a gas-to-liquids facility or mining project that began operation and production after December 31, 2010. Describes when a gas-to-liquids or mining project is considered to have begun operation and production.

Section 4. Amends AS 43.20.042(f) by updating the reference to an Internal Revenue Code provision for carrying forward the investment tax credit. Provides that the credit may not be carried forward to a tax year beginning after December 31, 2025.

Section 5. Amends AS 43.20.042(g) by stating that investments made after December 31, 2020 are not eligible for the credit under AS 43.20.042, except as provided in AS 43.20.042(f).

Section 6. Repeals and reenacts AS 43.20.042(h) and includes definitions for term used in AS 43.20.042.

Section 7. Amends the definition of "used in the state" in AS 43.55.900(24). The definition is relevant to particular tax limits in AS 43.55 (Oil and Gas Production Tax and Oil Surcharge).

DMB:plm
10-041.plm

ALASKA STATE LEGISLATURE

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Joint Armed Services Committee

Senator.Lesil.McGuire@legis.state.ak.us

SB 228 Backup Materials Table of Contents

1. *Reaching New Energy Frontiers Through Competitive GTL Technology*. Sasol Corporation
2. *Issues in Focus; Bringing Alaska North Slope Natural Gas to Market*. U.S. Energy Information Administration, 2009 Annual Energy Outlook
    a. *Bringing Alaska North Slope Natural Gas to Market*. Unedited White Paper for 2009 Annual Energy Outlook
3. *Beluga Coal-Gasification Feasibility Study*. U.S. Department of Energy/National Energy Technology Laboratory
4. *Alaska West Cook Inlet Coal to Liquids Project*. State of Alaska, AIDEA power point.
5. *Advanced Coal Technology: Wyoming Coal to Liquids Technology and State Incentives*. Legislative Research Services

Additional information will be available electronically.

FISCAL NOTE

STATE OF ALASKA
2010 LEGISLATIVE SESSION

Fiscal Note Number: 1
Bill Version: CSSB 228(RES)
(S) Publish Date: 3/23/10

Identifier (file name): SB228-REV-TAX-02-06-10
Title: Tax Incentives for Gas-to-Liquid
Sponsor: Senator McGuire
Requester: (S) Resources

Dept. Affected: Revenue
RDU: Taxation and Treasury
Component: Tax Division
Component Number: 2476

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	Appropriation Required	Information					
OPERATING EXPENDITURES	**FY 2011**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**	**FY 2016**
Personal Services							
Travel							
Contractual							
Supplies							
Equipment							
Land & Structures							
Grants & Claims							
Miscellaneous							
TOTAL OPERATING	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
CAPITAL EXPENDITURES							
CHANGE IN REVENUES ( )	**0.0**	**0.0**	***	***	***	***	***

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts							
1003 GF Match							
1004 GF							
1005 GF/Program Receipts							
1037 GF/Mental Health							
Other Interagency Receipts							
TOTAL	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Estimate of any current year (FY2010) cost:

POSITIONS

Full-time							
Part-time							
Temporary							

ANALYSIS: *(Attach a separate page if necessary)*

Changes in revenue are indeterminate. See attached analysis.

Prepared by: Johanna Bales, Deputy Director — Phone (907) 269-6628
Division: Tax Division — Date/Time 2-5-10; 6:44pm
Approved by: Ginger Blaisdell, Director — Date 2-6-10; 1:36pm
Administration Services Division

(Revised 11/6/2009 OMB)

3549

STATE OF ALASKA
2010 LEGISLATIVE SESSION

BILL NO. CSSB 228(RES)

ANALYSIS CONTINUATION

Bill Language:

This bill will allow an incentive tax credit for investment in a facility constructed to produce liquids from gas, coal, or biomass against a taxpayer's corporate income tax (CIT) liability. The credit would be 100 percent on the first $50 million of investment; 80 percent on the second $50 million of investment; 70 percent on the third $50 million of investment; 60 percent on the fourth $50 million of investment; and 40 percent of investment over $200 million but not more than $1 billion.

A taxpayer could only claim the credit on a project which begins operation and production after December 31, 2010 and on investments made after December 31, 2010 and before January 1, 2021 . The maximum credit that a taxpayer could claim for its investment in such a facility would be $475 million. However, the credit could not offset more than 60 percent of a taxpayer's CIT liability in any given tax year and any unused credit could be carried forward through tax years prior to January 1, 2026 (15 years). The first tax credits that could be claimed under the provisions of this bill would be in fiscal year 2012.

For Example: The State currently receives about $600 million a year in corporate income tax from our oil and gas taxpayers. If 10 taxpayers pay, an average of $60 million a year each, and two of those taxpayers build a GTL plant, the maximum credit they can claim is $475 million. That credit is limited to 60% of their current tax liability. So, if their tax liability increased to say $70 million due to sales from the facility, they could tax a maximum credit of $42 million each year for up to 15 years or until the full $475 million credit has been taken. Based on two taxpayers doing this, the effect would be $84 million in reduced corporate income tax for approximately 11.5 tax years.

Additionally, Section 7 of this bill would amend the definition of gas used in state to include gas used as raw material for producing liquids or petrochemicals.

Revenues:

Corporate income tax revenue would decline as a result of this bill by as much as $475 million per facility. However, since a taxpayer could not offset more than 60 percent of its current CIT liability in any given year, the decline in revenue would be limited each year as recoupment of the investment would be spread over several tax years. It is difficult to determine how many taxpayers would take advantage of this tax credit and invest in constructing a facility of this type in Alaska. Therefore, total affect on corporate income tax revenue as a result of this bill is indeterminate.

The provision in Section 7 of this bill would broaden the production tax treatment provided in AS 43.55.011(o) to include gas manufactured or otherwise converted to liquids or petrochemicals. The tax impact of this provision is also indeterminate for several reasons, including the uncertainty as to whether companies will take advantage of the provision, and if so, the magnitude of the project to be undertaken, the amount of gas to be committed, the price of the gas, and other factors.

Expenditures:

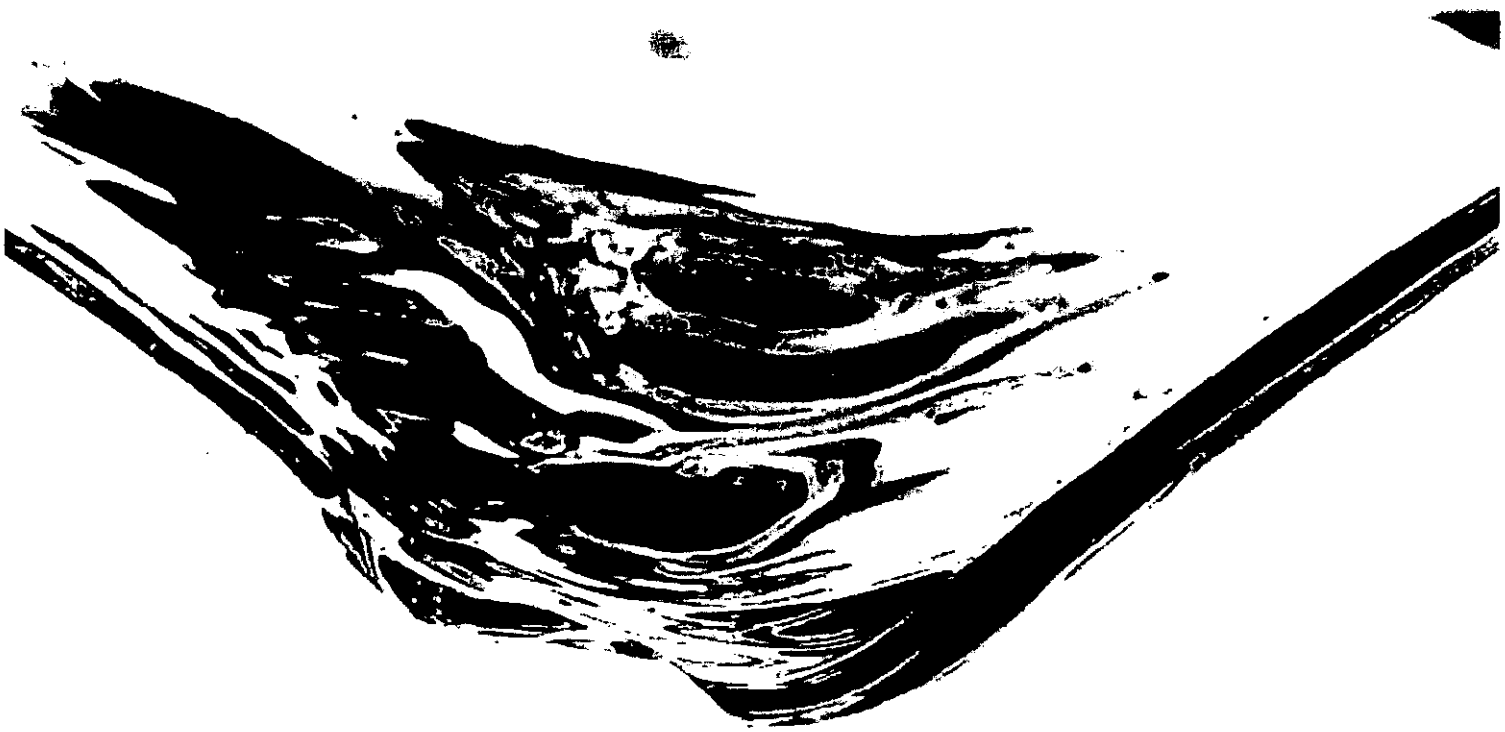
The provisions of this bill would most likely require the hiring of additional audit staff. It is not known at this time the number of position(s) that would be needed. Additional administrative work required of the Department would be dictated by the number of taxpayers who take advantage of the credit and the associated work required to validate those credits.

sasol
reaching new frontiers

reaching new energy frontiers

through competitive GTL technology

Sasol's integrated gas-to-liquids (GTL) solution offers significant economic, strategic and environmental benefits for many of the world's gas-rich countries. This proven technology – based on many years of focused research and development in Fischer-Tropsch synthesis technology in South Africa – presents an opportunity for gas-rich countries to diversify and expand their national energy sectors, while also substantially reducing the undesirable emissions produced by burning conventional diesel fuels.



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sasol at a glance

Leading the way through Fischer-Tropsch technology

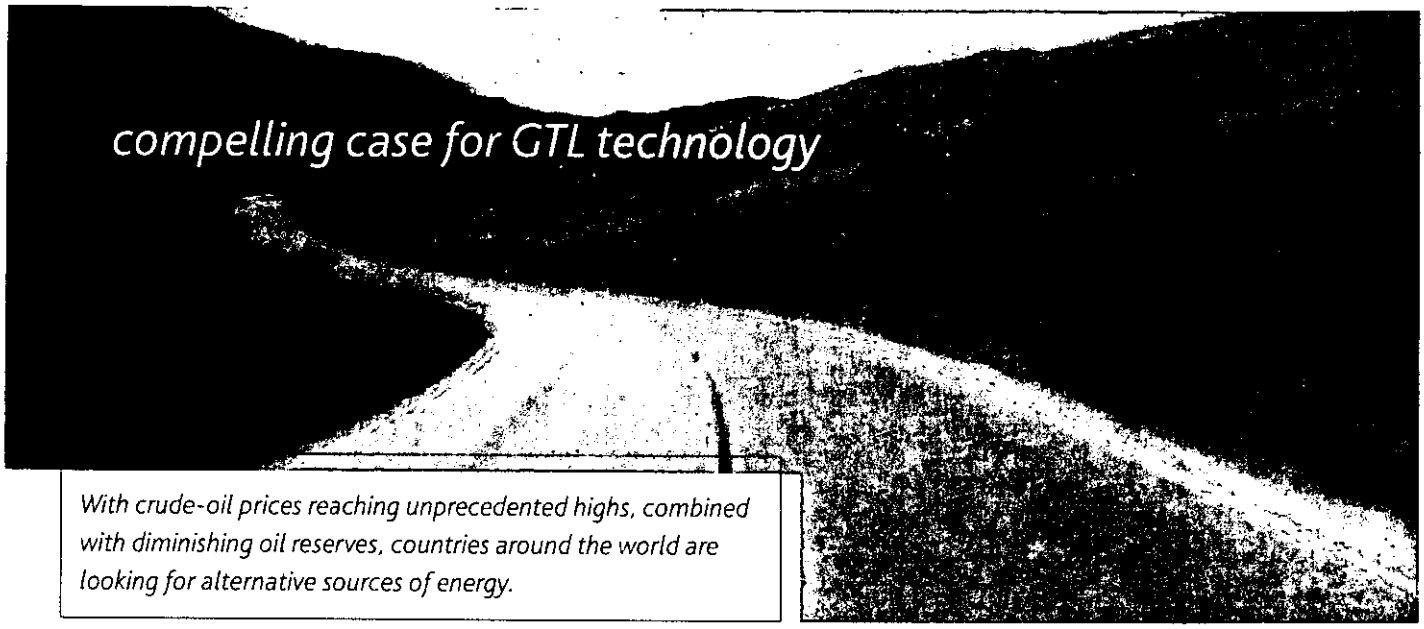
Sasol is an integrated oil and gas company with substantial chemical interests. Based in South Africa and operating worldwide, the company is listed on the New York Stock Exchange and the JSE stock exchange in Johannesburg, South Africa. Sasol is the leading provider of liquid fuels in South Africa and a major international producer of chemicals. It uses proprietary Fischer-Tropsch technologies to commercially produce synthetic fuels and chemicals from low-grade coal and natural gas.

Sasol has more than 50 years of proven commercial experience in producing synthetic fuels. Gas-to-liquids (GTL) technology is a step within the proven coal-to-liquids (CTL) technology that Sasol has perfected in South Africa. In fact, today, Sasol is world-renowned for operating the only world-scale coal-based synthetic fuel manufacturing facility in Secunda, south-east of Johannesburg. The Secunda plant produces 160 000 barrels a day (b/d) of fuel from coal.

Sasol manufactures more than 200 fuel and chemical products that are sold worldwide. In South Africa, Sasol also operates coal mines to provide feedstock for its synthetic fuels plants.

Sasol produces crude oil off the coast of Gabon, refines imported crude oil into liquid fuels in South Africa and retails liquid fuels and lubricants through a growing network of Sasol convenience centres and Exel service stations. Its liquid fuels interests also include wholesaling in South Africa and overland exports to several sub-Saharan African countries.

Sasol produces natural gas in Mozambique for supply to customers and as feedstock for some of its fuel and chemical production in South Africa. The company commissioned its first international joint-venture GTL plant in Qatar in 2006 and a second GTL plant is under construction in Nigeria for planned commissioning in 2009. These GTL ventures incorporate the proprietary Sasol Slurry Phase Distillate™ process.



compelling case for GTL technology

With crude-oil prices reaching unprecedented highs, combined with diminishing oil reserves, countries around the world are looking for alternative sources of energy.

Rising to global energy challenges

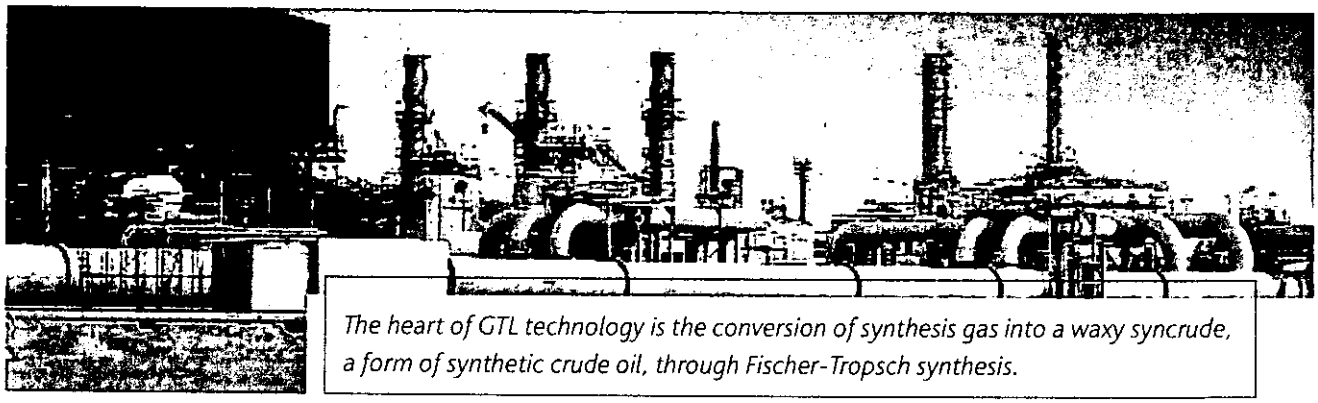
The case for investing in gas-to-liquids (GTL) fuel-production technology has become increasingly compelling. GTL technology offers an exciting opportunity for stakeholders to:

- *monetise underutilised natural gas resources;*
- *diversify economies and create new employment opportunities;*
- *reduce dependence on crude oil;*
- *counter geopolitical risks;*
- *use cleaner fuels and reduce emissions to the atmosphere; and*
- *manage dieselisation - the rapid growth in diesel-powered vehicles compared with their petrol-powered (gasoline) counterparts.*

With crude-oil prices reaching unprecedented highs (exceeding US$70,00 a barrel during May 2006), combined with diminishing oil reserves, countries around the world are looking for alternative sources of energy. Many are turning to gas. The world has abundant gas reserves, with an estimated 50% substantially underutilised.

Today, Sasol is providing its proven GTL technology to gas-producing countries like Qatar and Nigeria, allowing them to convert some of their gas reserves into a low-sulphur, low-aromatics form of synthetic diesel, GTL diesel. Backed by five decades of operational experience, as well as comprehensive research and development in Fischer-Tropsch process technology, Sasol has developed, and is marketing worldwide, its unique GTL technology, the Sasol Slurry Phase Distillate™ process.

understanding GTL technology



The heart of GTL technology is the conversion of synthesis gas into a waxy syncrude, a form of synthetic crude oil, through Fischer-Tropsch synthesis.

Turning gas into cleaner diesel

GTL technology comprises proven chemical processing technologies to convert natural gas into liquid fuels and related petrochemicals.

The heart of GTL technology is the conversion of synthesis gas into a waxy syncrude, a form of synthetic crude oil, through Fischer-Tropsch synthesis. Synthesis gas – or syngas – is a blend of hydrogen and carbon monoxide that can be used as the building block for producing more-complex molecules, such as those needed to make high-quality GTL diesel.

In the case of the Sasol Slurry Phase Distillate™ (Sasol SPD™) process, Sasol uses its proprietary low-temperature Slurry Phase Fischer-Tropsch technology to convert natural gas into GTL diesel, GTL naphtha and some liquefied petroleum gas (LPG). *(See page eight).*

Naphtha – a mixture of light hydrocarbons – is used as a feedstock for producing certain chemicals. GTL naphtha is ideal as a feedstock for producing ethylene. It is also ideal for fuel-cell applications.

LPG comprises gaseous hydrocarbons or petroleum gases such as propane, butane and pentane that are pressurised in liquefied form and used for heating.

The Fischer-Tropsch process – incorporated into both GTL technology and coal-to-liquids (CTL) technology – was first developed during the 1920s and has been advanced by Sasol in South Africa since the 1950s. Sasol's original Fischer-Tropsch research and development was focused on improving CTL technology.

During the 1980s, Sasol's focus began to include GTL technology. From this commitment, the group's unique GTL technology was born: the Sasol SPD™ process.

abundant gas reserves

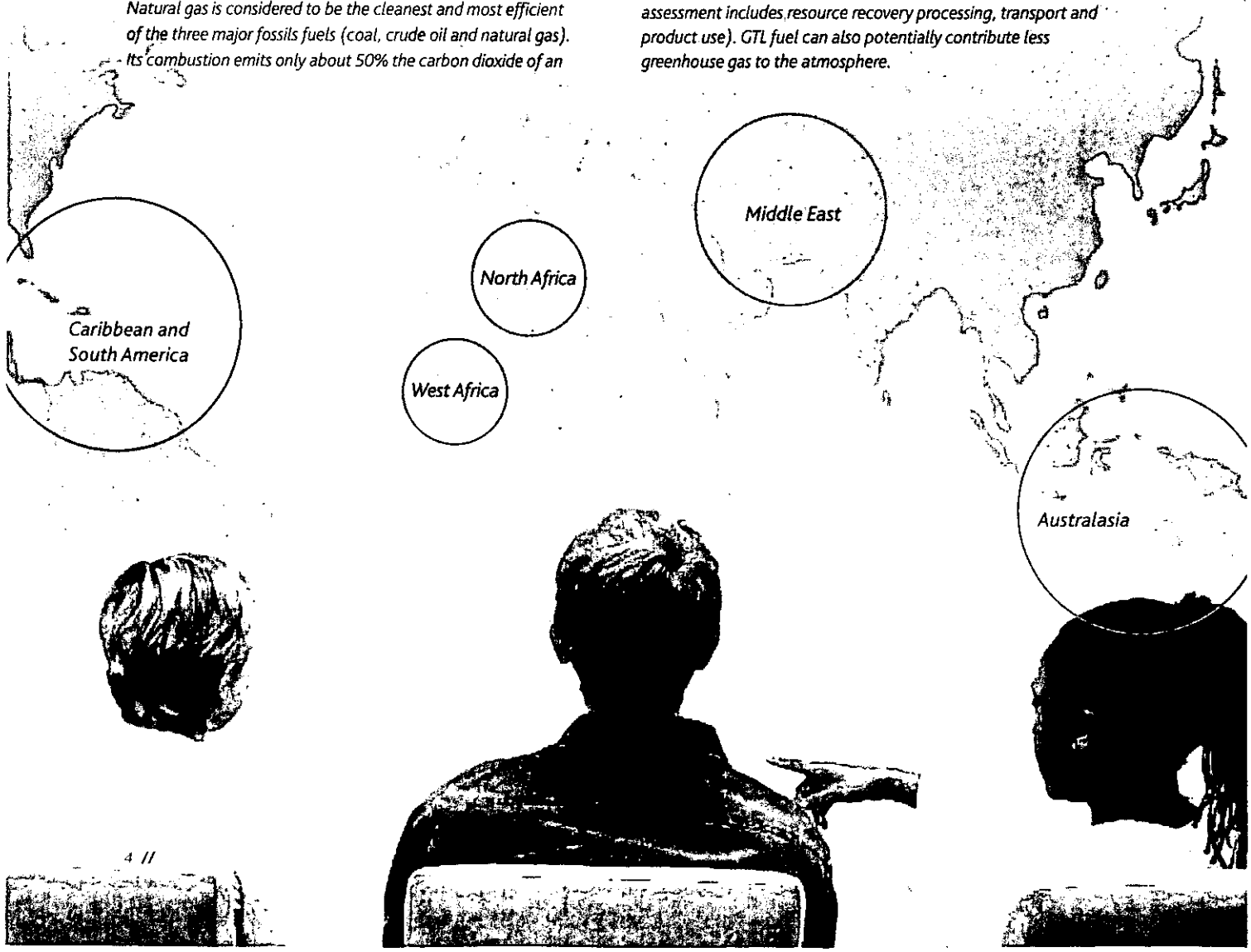
Providing an important new gas-monetisation solution

GTL plants are ideally suited for gas-rich countries, especially where the reserves are underutilised or where large amounts of associated gas are flared during commercial oil production.

The world has abundant reserves of natural gas: about 175-trillion cubic metres – an oil equivalent of at least 1 000-billion barrels. Major underutilised reserves are found in Russia, Iran, Qatar, other parts of the Middle East, parts of North America and Australia. Countries looking to eliminate the flaring of associated natural gas, like Nigeria, also present ideal opportunities for GTL.

Natural gas is considered to be the cleanest and most efficient of the three major fossils fuels (coal, crude oil and natural gas). Its combustion emits only about 50% the carbon dioxide of an equivalent amount of combusted coal. On the strength of this, along with its abundance, natural gas has in recent years become increasingly attractive as a hydrocarbon energy source for developed and emerging economies around the world.

Independent comparative studies recently conducted between traditional crude-oil refining and GTL technologies came to the same conclusion: volatile organic compounds, which contribute to smog, acidifying emissions like sulphur oxides and nitrogen oxides, as well as particulate emissions and waste are all drastically reduced in favour of the GTL product life cycle. (A full-product life-cycle assessment includes resource recovery processing, transport and product use). GTL fuel can also potentially contribute less greenhouse gas to the atmosphere.



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dieselisation and the changing energy paradigm

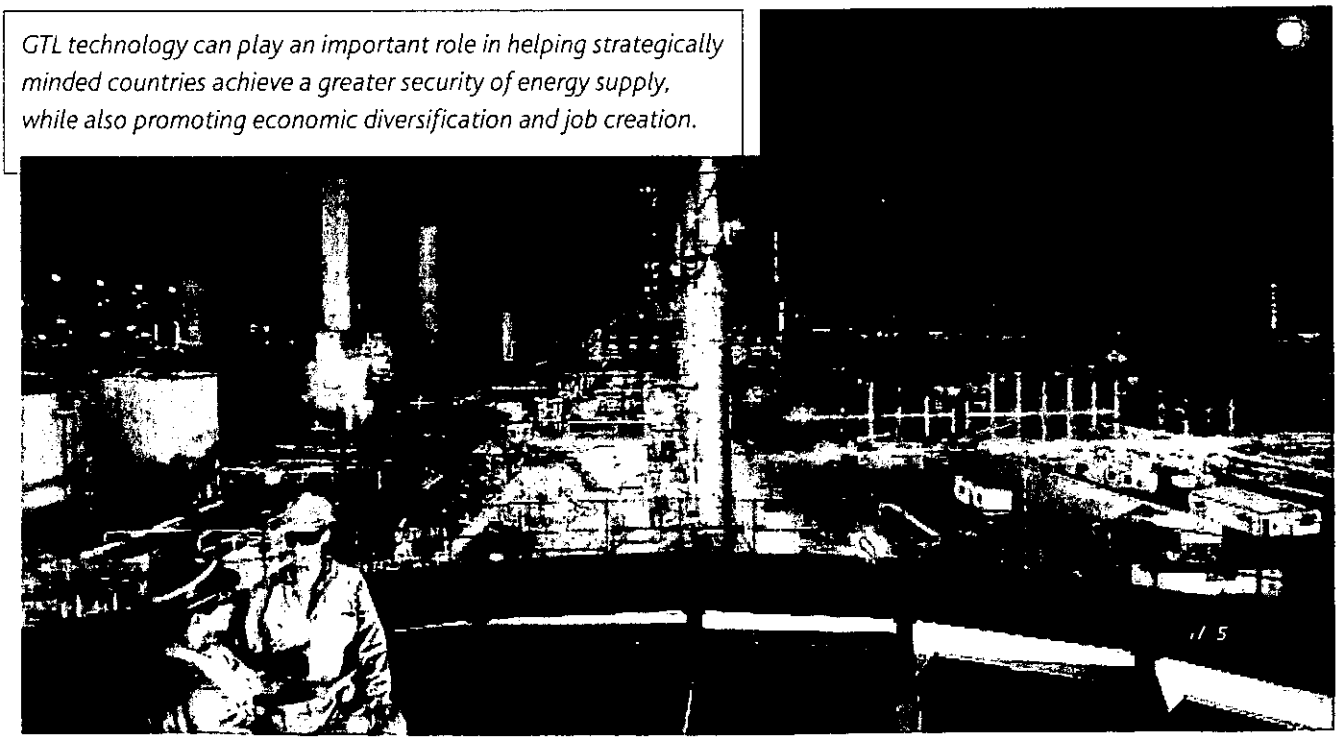
Bringing a smart solution to rapid dieselisation

GTL diesel offers a potentially far-reaching solution for the world's changing energy paradigm, most notably because of the dramatic rise in diesel consumption in both developed and emerging economies.

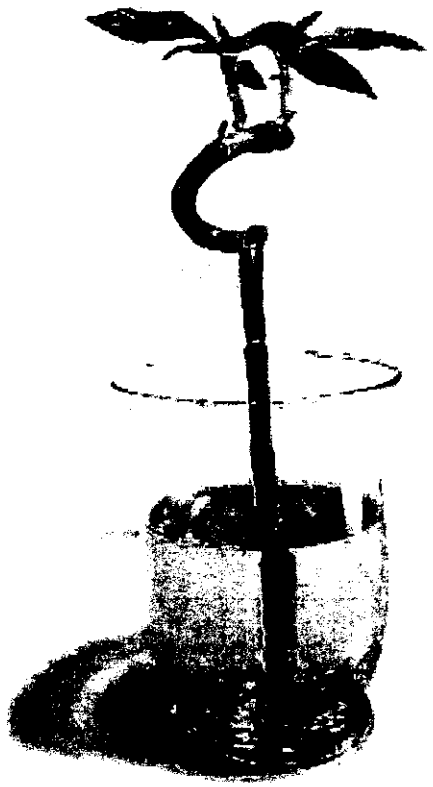
With crude-oil prices escalating, GTL technology plays an important role in helping strategically minded countries achieve a greater security of energy supply, while also promoting economic diversification and job creation.

The case for GTL technology is further strengthened by the growing demand from consumers, environmentalists, governments and automotive producers for cleaner, higher-performing fuels. Diesel is far more energy efficient than petrol and contributes to the drive to reduce carbon dioxide emissions in the transportation sector.

GTL technology can play an important role in helping strategically minded countries achieve a greater security of energy supply, while also promoting economic diversification and job creation.



benefits of GTL products



GTL diesel is positioned as a clean, premium product or as a blend stock to enhance the quality of conventional diesels.

Offering a cleaner, better-performing diesel

GTL diesel is of significant higher quality than diesel derived from crude oil. GTL diesel has a high cetane number (at least 70 compared with a 45 to 55 rating of most diesels), low sulphur (less than five parts per million), low aromatics (less than 1%), and good cold flow characteristics, which can be optimised to suit specific applications.

GTL diesel is positioned as a clean, premium product or as a blend stock to enhance the quality of conventional diesels.

Best of all, GTL diesel can be used in all modern diesel engines. Its high-quality properties result in reduced noise and other performance benefits. The high cetane number and very low levels of sulphur and aromatics ensure a more efficient and cleaner-burning combustion environment. This leads to a substantial reduction in engine wear and exhaust emissions.

Significantly, too, GTL diesel is compatible with established fuel distribution infrastructures. It can therefore be distributed by ship, road tanker or rail tanker without transport operators having to undertake new investments to modify their equipment. It can also be used with both current and envisaged future engine and exhaust technologies. Compression-ignition vehicles using GTL diesel do not need to undergo any engine or exhaust system modifications.

GTL ventures offer other benefits. A high-quality GTL naphtha is also produced in the Fischer-Tropsch process. With a high content of paraffins and very low contents of sulphur, naphthenes and aromatics, it is ideal as cracker feedstock to produce ethylene for the plastics industries (mostly for producing polyethylene and polyvinyl chloride).

sasol's role in promoting GTL

Promoting optimum competitiveness

Since the mid-1990s, Sasol has focused on developing GTL ventures internationally with world-renowned partners.

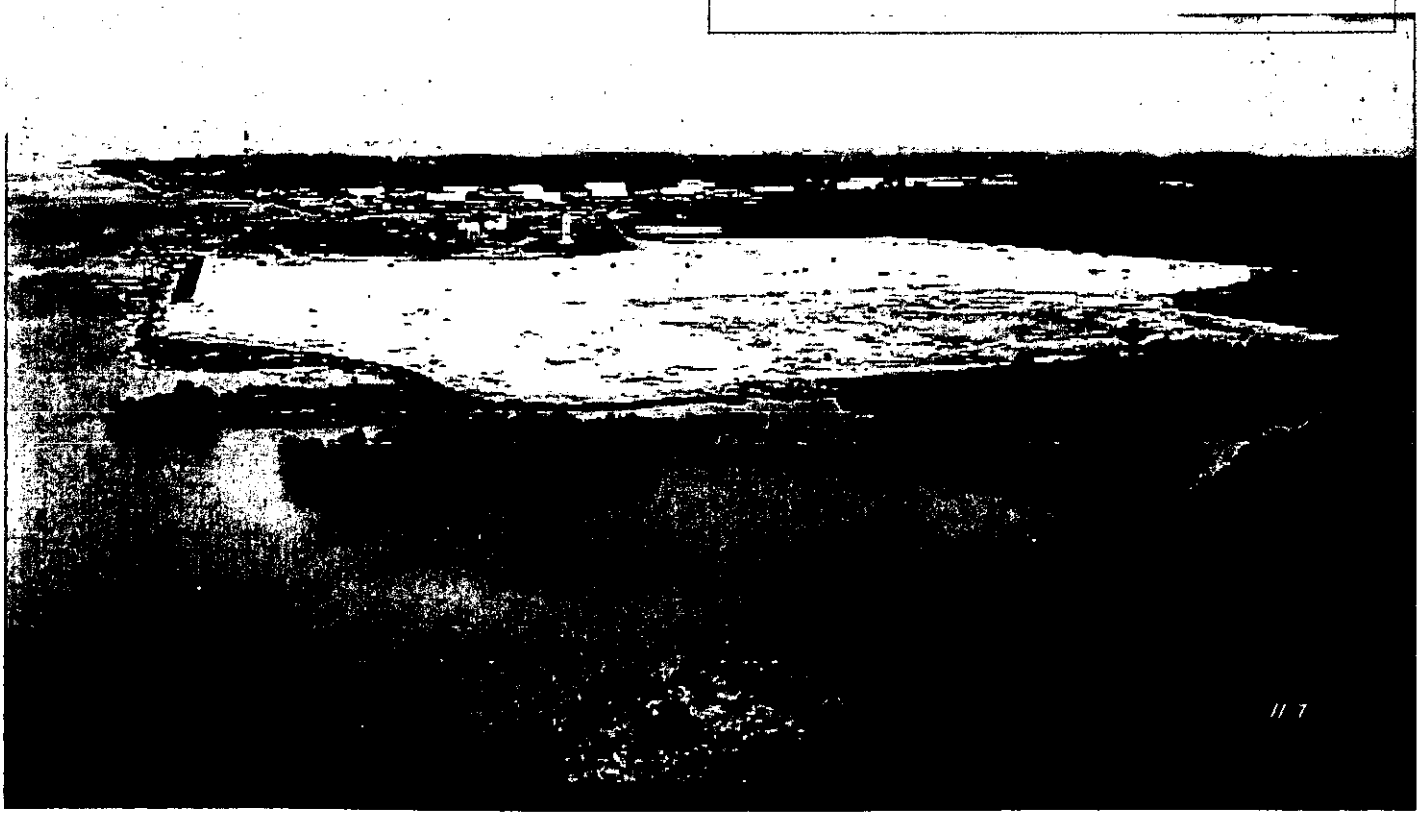
Sasol formed a joint venture with Chevron of the USA, Sasol Chevron, to develop sustainable GTL projects, as well as market and distribute GTL products worldwide.

Such partnerships make good business sense. Besides creating greater synergy in areas such as technology, plant design and plant operations, GTL partnerships also enable large capital investments. GTL ventures, such as the ORYX plant in Qatar, require at least US$1-billion to develop.

In Qatar, Sasol has partnered with the state oil company, Qatar Petroleum, while in Nigeria it has, through Sasol Chevron, entered into a venture with the National Nigerian Petroleum Company and Chevron Nigeria Limited.

Sasol offers gas-rich countries a proven gas-beneficiation technology that can be used to monetise underutilised gas reserves. Sasol also offers extensive operating experience, having brought on stream its first Fischer-Tropsch-based CTL venture in 1955. Since then, Sasol has undertaken extensive research and development in Fischer-Tropsch synthesis technology and patented several processes and specialised catalysts.

Sasol offers countries such as Nigeria extensive operating experience.



sasol Slurry Phase Distillate ™ process

Converting natural gas into high-quality diesel

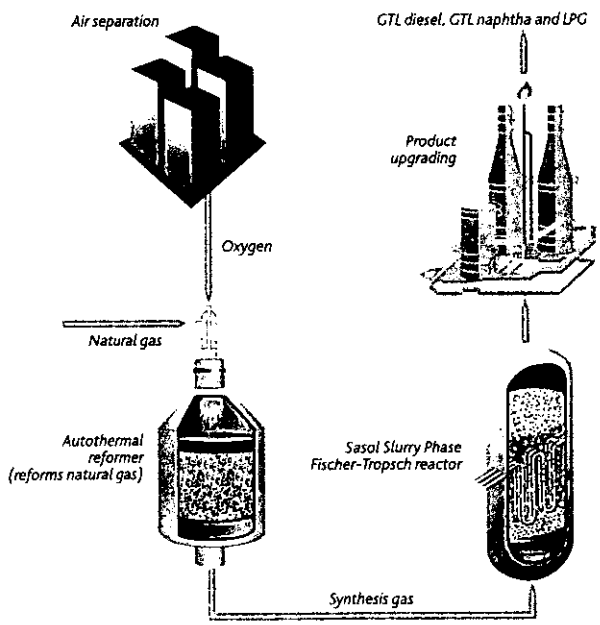
The fully integrated, three-step Sasol Slurry Phase Distillate ™ (Sasol SPD ™) process dates back to the 1980s when Sasol developed its low-temperature Slurry Phase Fischer-Tropsch reactor at Sasolburg. Combined with a proprietary iron- or cobalt-based catalyst, this technology allows for the creation of chemicals and liquid fuels from either coal or gas.

The first Sasol SPD™ process step is gas reforming. Here, natural gas reacts with oxygen and steam over a catalyst to produce synthesis gas (syngas). To achieve this, Sasol and its global GTL partners use Haldor Topsøe's proven autothermal reforming technology.

The second process step entails Fischer-Tropsch synthesis through which syngas is converted into longer-chain or waxy hydrocarbons in the reactor. Syngas is fed to the bottom of the reactor where it is distributed into a slurry consisting of liquid wax and particles of Sasol's proprietary advanced cobalt catalyst. As the gas bubbles up through the slurry, it diffuses into the catalyst and is converted into waxy syncrude.

The long-chain wax product is then separated from the slurry containing the catalyst particles in a proprietary Sasol process. The lighter, more volatile fractions leave in a gas stream from the top of the reactor. The gas stream is cooled to recover the hydrocarbons that have a lower molecule weight (the lighter cuts), as well as some quantities of water.

The hydrocarbon streams are then sent to the product-upgrading unit for the third step, which uses Chevron Isocracking™ technology. This step produces the final GTL diesel, GTL naphtha and LPG.



Sasol Slurry Phase Distillate ™ process

leading the way in Qatar and Nigeria

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Sasol's first two GTL projects

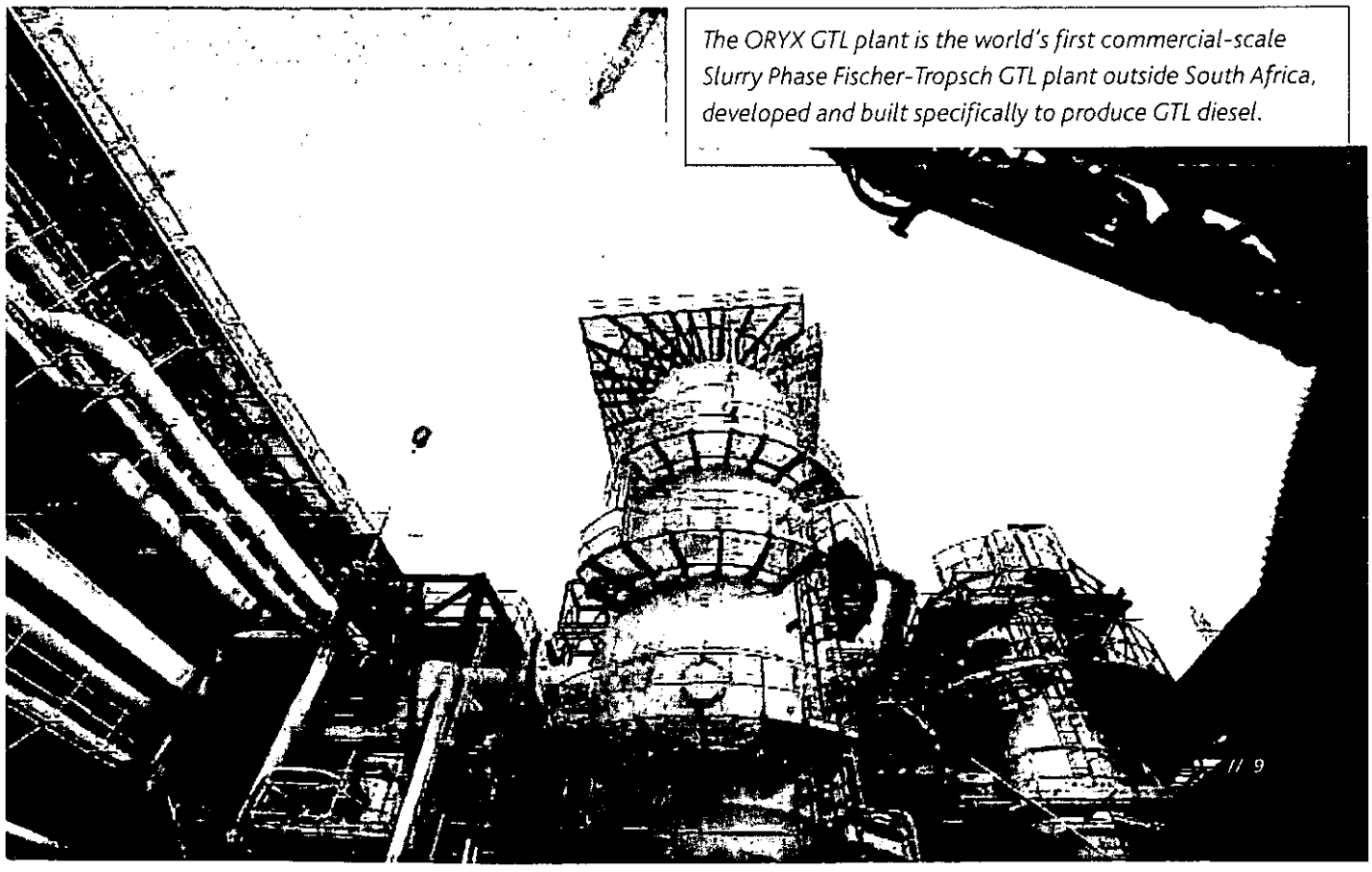
Sasol inaugurated its first GTL project, the ORYX GTL venture, at Ras Laffan on the north-eastern seaboard of Qatar, in partnership with Qatar Petroleum, in June 2006.

The engineering, procurement and construction contract for this project commenced in early 2003. Developed at a cost of about US$1-billion, the 34 000 b/d ORYX GTL plant uses the Sasol SPD™ process.

The ORYX GTL plant is the world's first commercial-scale Slurry Phase Fischer-Tropsch GTL plant outside South Africa, developed and built specifically to produce GTL diesel and, to a lesser extent, GTL naphtha and LPG. It will produce about eight-million barrels a year of GTL diesel as a fuel to be used either neat or as blend stock.

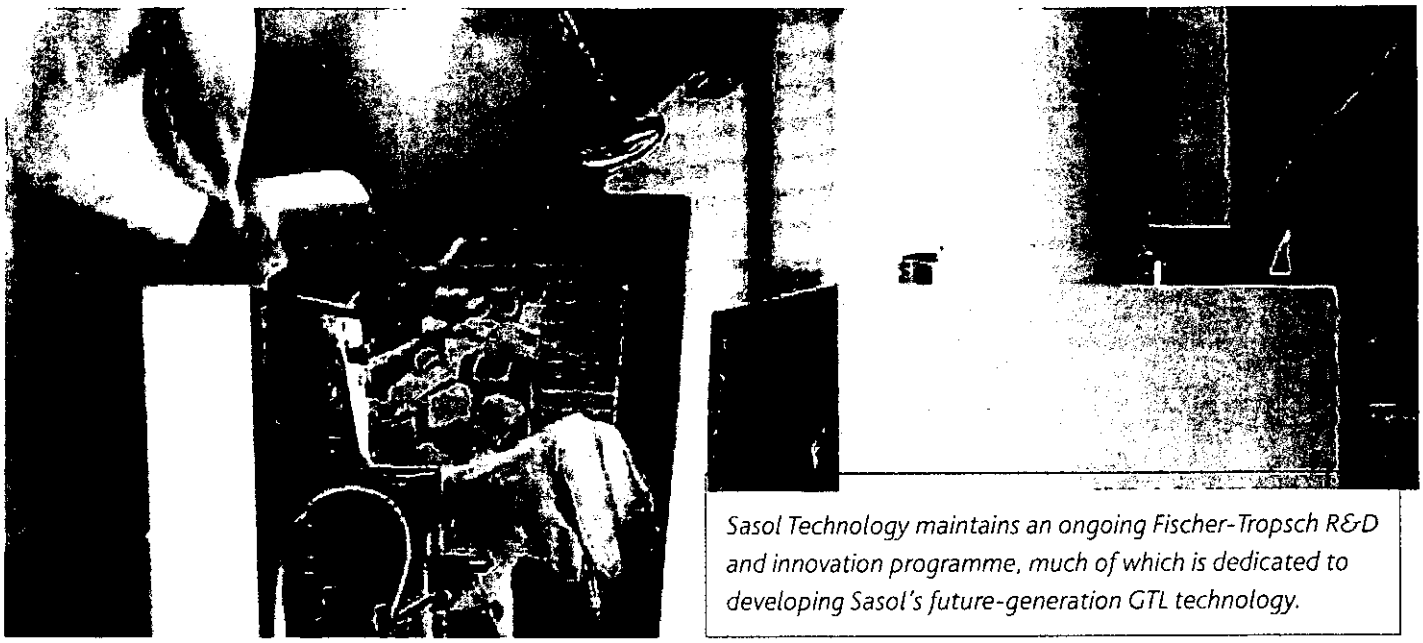
To complement the ORYX project, Sasol and Sasol Chevron are working with the National Nigerian Petroleum Corporation and Chevron Nigeria Limited to develop another 34 000 b/d GTL project, the EGTL plant at Escravos in the Niger Delta. Construction work commenced in 2006 and the plant is expected to go into production in 2009. It will also use the Sasol SPD™ process to produce GTL diesel, GTL naphtha and some LPG.

Sasol is engaged in exploratory discussions with other gas-rich countries with a view to developing additional GTL plants.



The ORYX GTL plant is the world's first commercial-scale Slurry Phase Fischer-Tropsch GTL plant outside South Africa, developed and built specifically to produce GTL diesel.

technological development and support



Sasol Technology maintains an ongoing Fischer-Tropsch R&D and innovation programme, much of which is dedicated to developing Sasol's future-generation GTL technology.

Partnering to sustain a culture of innovation

Sasol has long been an enthusiastic champion of its Fischer-Tropsch technology, having invested substantial funds and intellectual capital to advance this technology.

Sasol Technology maintains an ongoing Fischer-Tropsch R&D and innovation programme, much of which is dedicated to developing Sasol's future-generation GTL technology. Its research – covering specifics such as iron- and cobalt-based catalysis and Fischer-Tropsch reactor design – is focused on opportunities to enhance the performance of Sasol's GTL process, while also lowering capital costs, increasing process flexibility and improving eco-efficiency.

To strengthen its Fischer-Tropsch R&D, Sasol operates two complementary research groups at St Andrews University in Scotland and Twente University in the Netherlands. The group also maintains technology partnerships with other major technology players, including Chevron for Isocracking™ and Haldor Topsøe for reforming.

At De Meern, near Utrecht in the Netherlands, Sasol has partnered with the US-based catalyst producer, Engelhard, to commercialise and operate a unique chemical plant devoted to producing Sasol's advanced cobalt catalyst now being used in the ORYX GTL plant.

Sasol Technology maintains other beneficial partnerships, some of which are focused on Sasol's GTL fuel technology. Sasol has been working with original equipment manufacturers, including Caterpillar, Citroën, DaimlerChrysler, Peugeot and Volkswagen. It is also collaborating with Engelhard, Johnson Matthey and other catalyst producers to evaluate the effects of new-generation Sasol diesel and petrol on automotive catalysts.

Sasol also maintains close links with reputable research and testing organisations in Europe and the USA, including the Southwest Research Institute at San Antonio, Texas. These collaborators have been closely involved in testing the technical and environmental characteristics of the GTL diesel produced through the Sasol SPD™ process.

In addition, Sasol has an alliance with the Ishikawajima-Harima Heavy Industries (IHI) engineering consortium in Japan for the fabrication of the specialised Slurry Phase Fischer-Tropsch reactors used in the Sasol SPD™ process. IHI fabricated the two reactors for the ORYX GTL plant and is fabricating another two for the EGTL project.

GTL glossary

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reaching new frontiers

associated gas: *natural gas found with crude oil in an underground geological formation.*

autothermal reformer: *a type of catalytic partial-oxidation reactor in which the endothermic heat needed for chemical reforming is provided by combustion reactions of oxygen in the feed.*

beneficiation: *a process used to increase the value of a material or chemical.*

blend stock: *an ultra-low-sulphur diesel that is blended with a conventional diesel to reduce the latter's sulphur content on a parts-per-million basis.*

catalyst: *usually a metal or metallic compound that enables a reaction to occur between two or more chemicals that would not otherwise react – or to promote the speed and efficiency of a reaction between these chemicals.*

cetane (hexadecane, $C_{16}H_{34}$): *a colourless, liquid, straight-chain paraffin (alkane) used to standardise the knock rating of diesel.*

chain: *chemically, pertaining to a line of atoms of the same type in a molecule. A chain can be open (straight-chained or branch-chained) or closed (ringed).*

cold-start ignition: *the ability to start a vehicle's engine in cold conditions, usually at temperatures of below freezing.*

distillation: *boiling or re-evaporating a liquid and then recondensing it and collecting the vapour.*

hydrocarbons: *a general term for organic compounds containing only, or primarily, carbon and hydrogen molecules.*

Isocracking™: *proprietary Chevron technology used to selectively crack long-chain waxy molecules to produce the mildly isomerised middle-distillate products of GTL diesel, kerosene and GTL naphtha.*

life-cycle assessment: *a process of formally identifying and understanding the flow of energy and materials through a manufacturing system, commencing from a raw material in the ground, through processing and product manufacture, and ending with post-consumer product disposal.*

linear: *pertaining to organic chemicals with a straight-chain molecular structure, rather than branched chains.*

liquefied petroleum gas (LPG): *gaseous hydrocarbons such as propane, butane and pentane pressurised in liquefied form and used for heating.*

methane (CH_4): *a colourless, odourless gas that combusts easily and produces a pale, slightly luminous flame; it is the main constituent of natural gas and can undergo chemical reforming to produce syngas.*

naphtha: *a generic term for a flammable, light distillate or hydrocarbons feedstock, or a mixture of light hydrocarbons, used for gas or petrochemicals manufacture.*

paraffins (alkanes): *saturated aliphatic hydrocarbons of the generic formula CnH_{2n+2} found in natural gas and crude oil. They are indifferent to oxidising agents, hence the Latin-derived name of paraffin meaning "little allied". The names of specific paraffins end with an -ane suffix and include methane, ethane, propane, butane, pentane, heptane and octane. The first four, methane to butane, are gases, the higher numbers are liquids and those above $C_{16}H_{34}$ are waxy solids.*

particulates: *microscopic air-borne material, such as sand, ash or dust, from either natural occurrences, such as volcanoes and dust storms, or industrial activities, such as coal burning.*

reactor: *an enclosed vessel inside which a predetermined and controlled chemical reaction occurs as part of a chemical manufacturing process.*

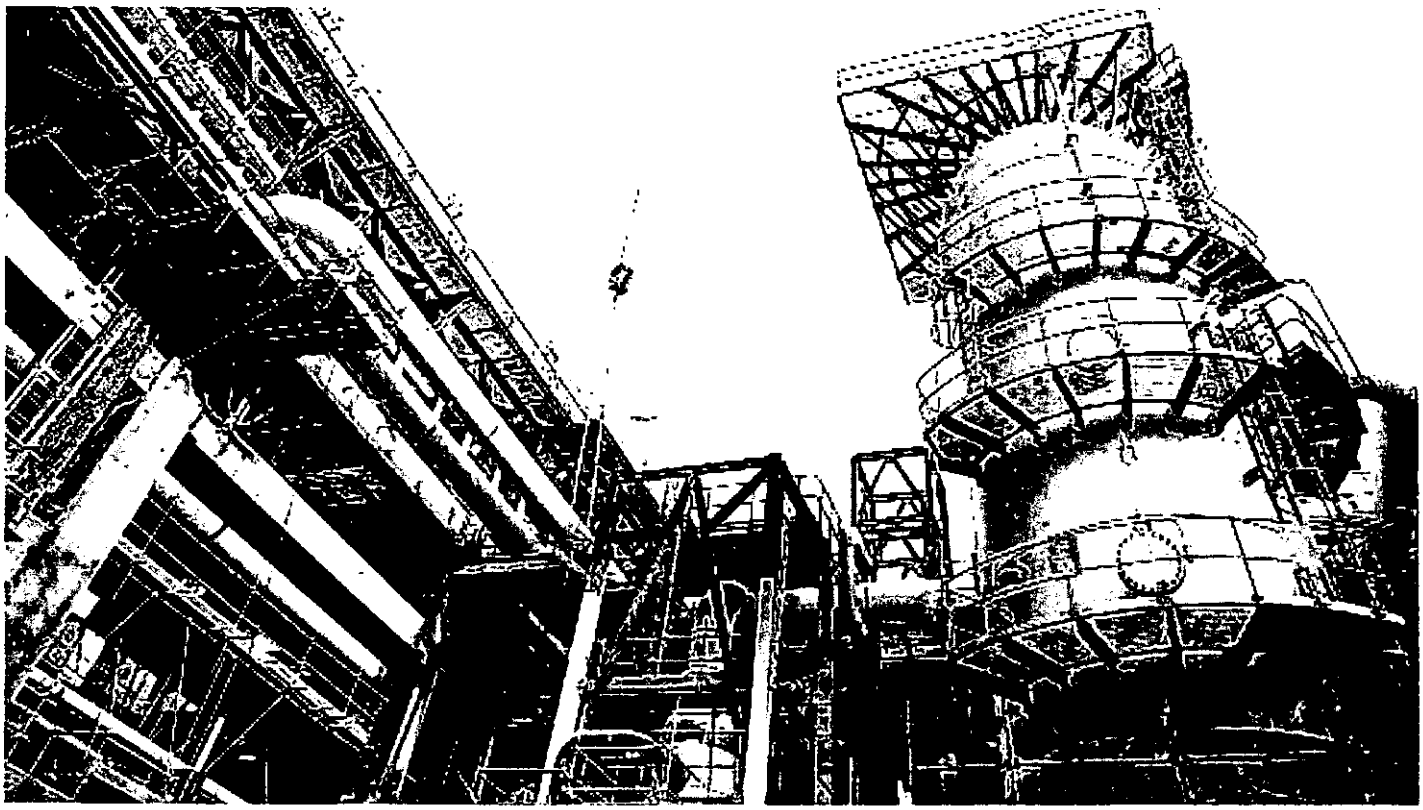
reforming: *the conversion of straight-chain paraffins into branch-chained ones through cracking or catalytic reaction.*

slurry: *a liquid containing an appreciable amount of suspended solids.*

synthesis: *the formation of more-complex chemical compounds or molecules from simpler compounds or molecules.*

synthesis gas (syngas): *a carbon monoxide-hydrogen mixture used as a petrochemicals feedstock for synthesis and normally derived from the partial oxidation, or catalytic reaction with steam, of methane, which can be derived through natural gas reforming or coal gasification.*

contacts



For more information on Sasol's GTL technology and strategy, please contact ***Anne Buchanan****, communications manager of Sasol Synfuels International*

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disclaimer

Forward-looking statements

In this publication we make certain statements that are not historical facts and relate to analyses and other information based on forecasts of future results and estimates of amounts not yet determinable, relating, among other things, to volume growth, increases in market share, total shareholder return and cost reductions. These are forward-looking statements as defined in the US Private Securities Litigation Reform Act of 1995. Words such as "believe", "anticipate", "expect", "intend", "seek", "will", "plan", "could", "may", "endeavour" and "project" and similar expressions are intended to identify such forward-looking statements, but are not the exclusive means of identifying such statements. Forward-looking statements involve inherent risks and uncertainties and, if one or more of these risks materialise, or should underlying assumptions prove incorrect, actual results may be very different from those anticipated.

The factors that could cause our actual results to differ materially from such forward-looking statements are discussed more fully in our most recent annual report under the Securities Exchange Act of 1934 on Form 20-F filed on October 26 2005 and in other filings with the United States Securities and Exchange Commission (SEC).

Such forward-looking statements apply only as of the date on which they are made, and we do not undertake any obligation to update or revise any of them, whether as a result of new information, future events or otherwise.

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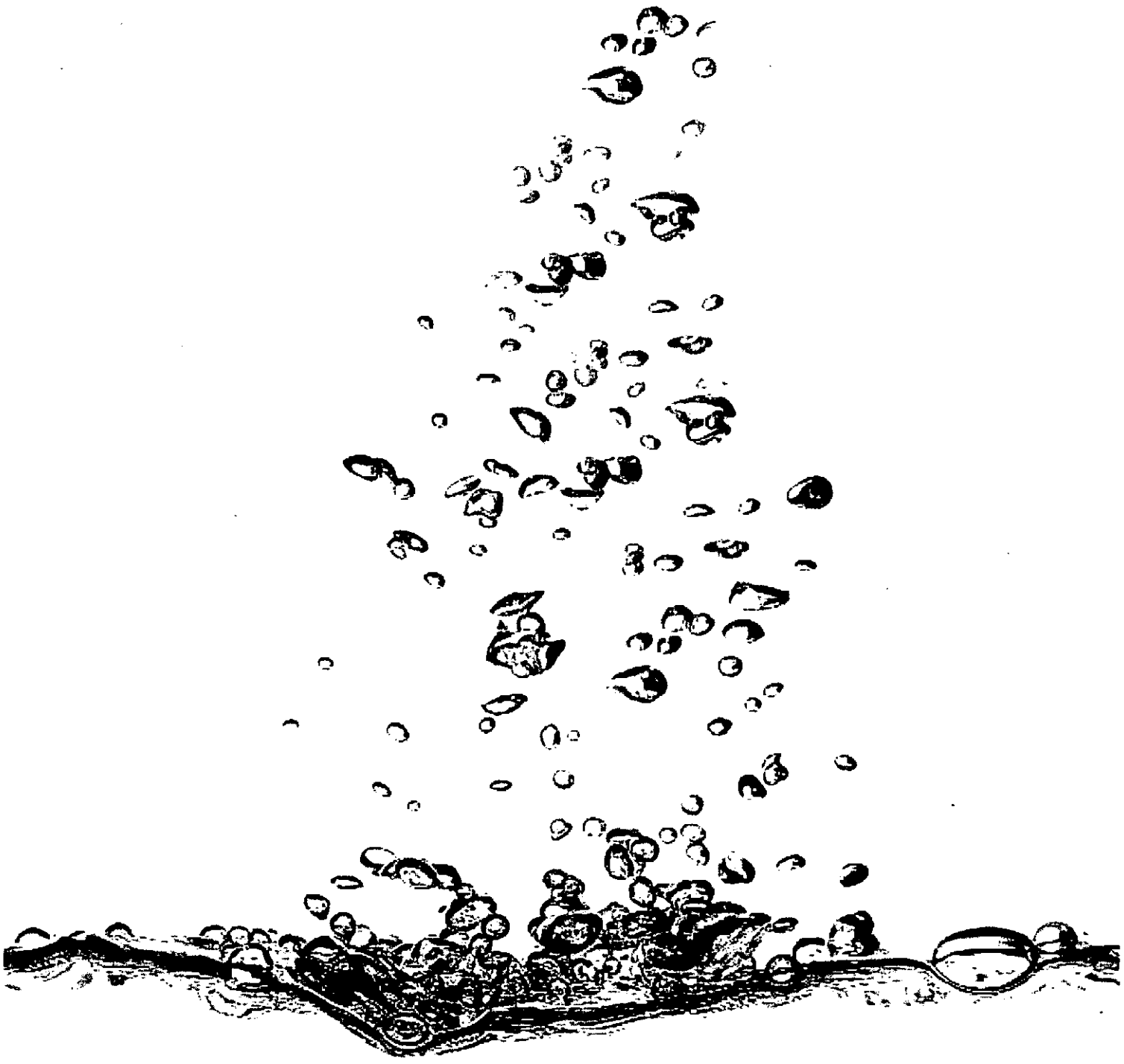
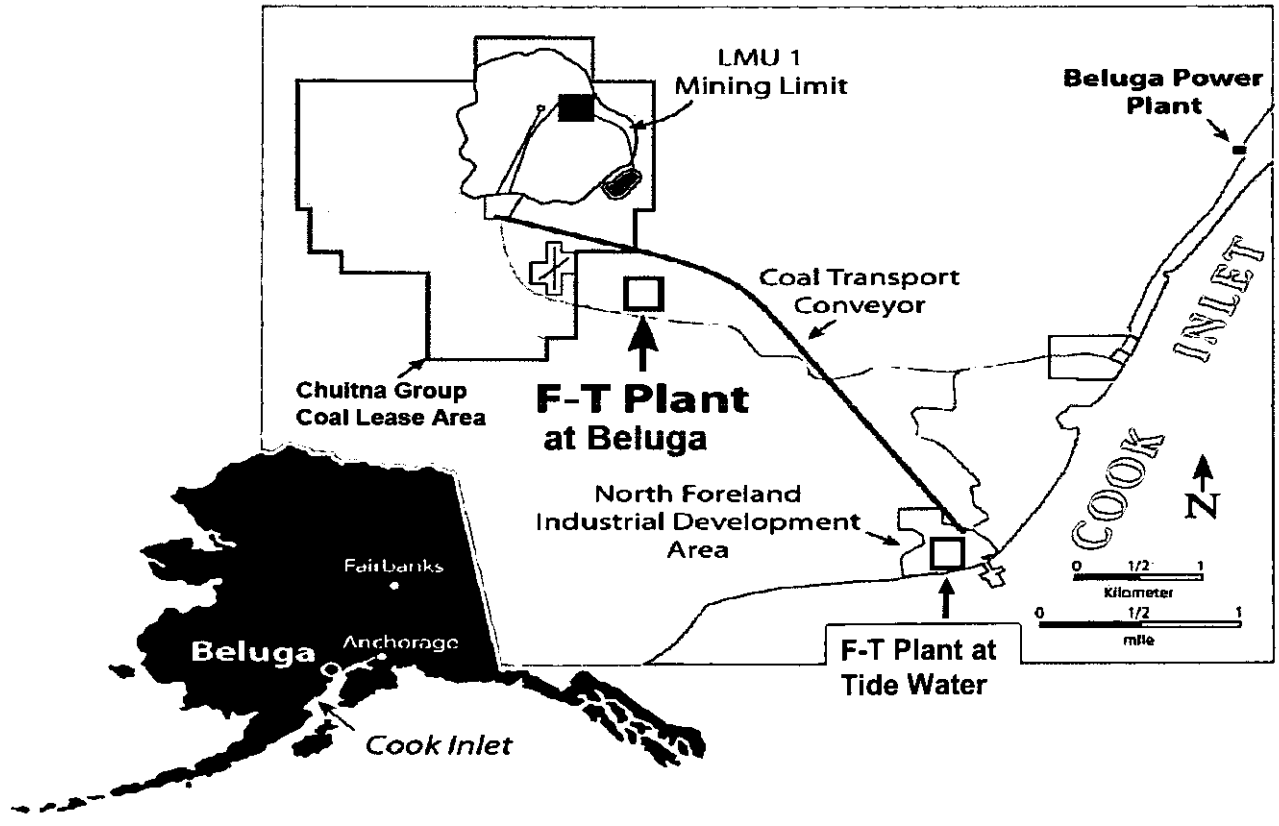


ALASKA WEST COOK INLET
Coal To Liquids Project

80,000 bbl/d Coal To Liquids "Beluga CTL Plant"
(Mine Mouth or Tide Water)



ALASKA BELUGA CTL PROJECT – THE RIGHT CHOICE...✓

- ☑ REASONABLE RATE OF RETURN FOR EQUITY OWNERS;
- ☑ Beluga CTL plant and coal reserves next to the tide water;
- ☑ The Beluga coal field has 50+ years of supply;
- ☑ CO_2 sequestering available through local depleted gas fields;
- ☑ CO_2 enhanced oil recovery in local reservoirs – 150 to 300 million barrels;
- ☑ Local electric market needs 350 to 450 MW of new power;
- ☑ 12 miles from electric grid serving 85% of Alaska's electric load;
- ☑ 10 miles from natural gas transmission system delivering 500 mmcf/d;
- ☑ Almost half of Alaska's population lives within 65 miles of CTL site;
- ☑ 80% of the engineering, design, fabrication, construction and operating companies serving Alaska's North Slope and Cook Inlet oil and gas industry are located within 45 miles of the proposed CTL site;

ADDITIONAL POINTS THAT WILL FAVOR AN ALASKA CTL PLANT

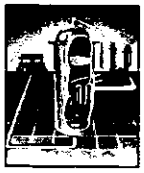
- ☑ 30 miles from Drift River oil export terminal - 500,000 bbl tankers;
- ☑ 20 miles from an existing
  - ☑ 70,000 bbl/d crude oil refinery - Tesoro
  - ☑ A 1.5 million ton/yr fertilizer plant – Agrium
  - ☑ A 1 million barrel tank farm with import/export dock and a products pipeline to the Anchorage fuels market;
- ☑ The Port of Anchorage 45 miles from CTL plant site;
- ☑ The State of Alaska has received a Federal Grant to build a bridge across the inlet from Anchorage to the west side of the Cook Inlet;
- ☑ The State of Alaska has obtained right of way & is looking at building a road and extending the Alaska Rail Road down the west side of the Cook Inlet to aid in commercial development;
- ☑ Alaska Rail Road could potentially provide tax free revenue bonds to aid in financing;
- ☑ Weather conditions similar to Chicago – not the arctic;
- ☑ The Alaska CTL site is a short tanker trip to one of the highest price fuel markets

WHAT DOES A BELUGA CTL PROJECT REPRESENT FOR ALASKANS?

- A $5 Billion World Class CTL Plant
- 1,300 Permanent Jobs
  - Over 5,000 during construction
- 2 Billion Barrels of Transport Fuels
  - Equivalent to a 6 billion bbl oil field
- 6 TCF of Natural Gas
  - Energy Equivalent in waste heat recovery
- 350 + Million Barrels of EOR Crude Oil
  - $1.75 billion in State Royalty money
- 380 MW of Low Cost Waste Heat Electricity
  - $900 million in rate payer savings over 15 years
  - Near Zero CO_2 Emission Electricity
- State and Local Tax Revenue
  - $1 billion in local tax revenue over 20 years
- Western Cook Inlet Land Development
- Over 16 Million ton/yr of Coal Production
- Manufacture of Value Added Products in Alaska

CONVERTING PROVEN WEST COOK INLET BELUGA COAL RESERVES INTO

"PROVEN"
TRANSPORTATION FUELS
&
PETROCHEMICAL FEED STOCKS

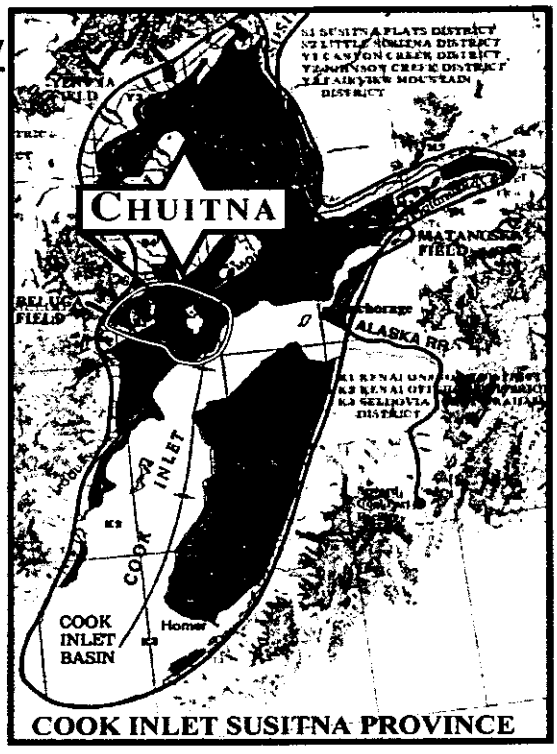


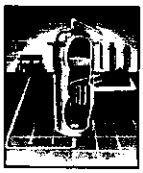
COOK INLET/SUSITNA COAL PROVINCE

Resource & Reserve Summary

million tons of coal – billion of barrels of equivalent liquids

Coal Resource	M-tons	B-bbls
° Hypothetical Resource	64,230	96
° Identified Resource	10,550	15.6
• Measured Resource	1,300	2.0
• Chuitna Measured Reserve	1,000	1.5
° Chuitna Proven Reserves	700	1.05
° Barrick Reserves	600	1.0





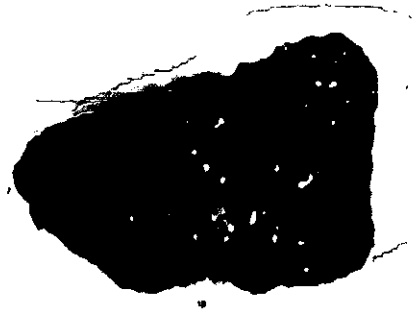
COAL TO LIQUIDS

F-T DIESEL

BILLIONS OF TONS OF COAL

EQUALS

BILLIONS OF BARRELS

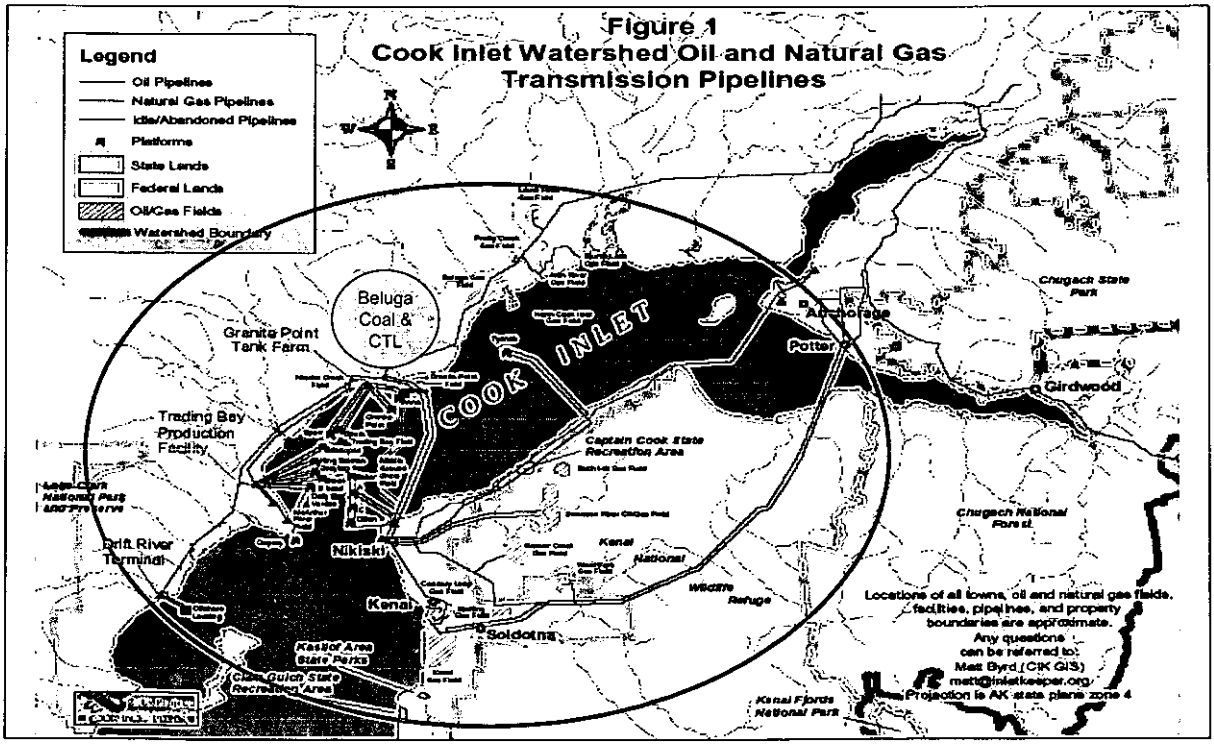


WHAT DOES 1.3 BILLION TONS OF WEST COOK INLET COAL REPRESENT

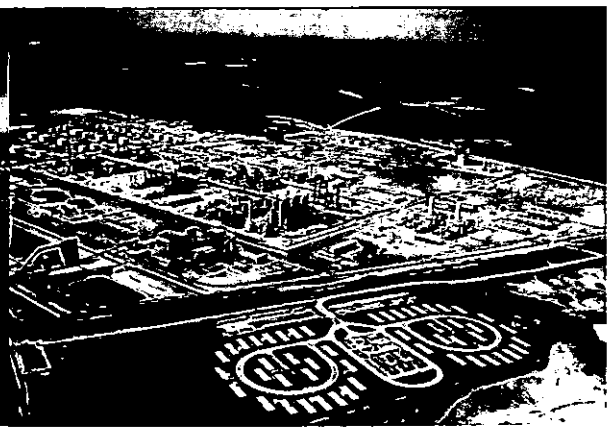
- 2 BILLION BARRELS OF FUELS
  - The SASOL F-T process will turn 1 ton of West Cook Inlet coal into 1.5 barrels of product
  - 1.5 barrels x 1.3 billion = 2 billion barrels of fuels
- 2 Billion of "RECOVERABLE" barrels
  - 2 Billion barrels of recoverable crude is the equivalent of a 6 Billion barrel oil find

Note: the F-T conversion process depends upon the quality of the coal, (ie. the carbon content)
Assume that 3 to 4 tons of Alaska coal will produce 1 ton of F-T fuels. 1 ton of F-T fuels is approximately 326 gallons.
326 gallons is equal to 7.76 barrels thus 1 ton of Alaska coal could produce 2 to 2.6 barrels of finished fuels.

COOK INLET OIL & GAS FACILITIES



South African Secunda 150,000 BPD Coal to Liquids (CTL)



South African Mossgas 47,000 BPD Gas to Liquids (GTL)

Shell Bintulu 15,000 BPD Gas to Liquids (GTL)

THE F-T PROCESS IS COMMERCIAL

260,000 bbl/d already proven and operational in South Africa & Malaysia

500,000 bbl/d coming soon to Qatar

300,000+ bbl/d coming soon to China

A CTL/BTL PLANT PRODUCES FISCHER-TROPSCH (F-T) TRANSPORT FUELS AND PETROCHEMICAL FEEDSTOCKS SOME OF THE CLEANEST FUELS IN THE WORLD

BUT WHAT IS THE F-T PROCESS?

The Fischer-Tropsch Synthesis

$$2\,CO(g) + H_2(g) \rightarrow (-CH_2-)_n(l) + CO_2(g) + H_2O$$

Okay, don't let the chemistry scare you!

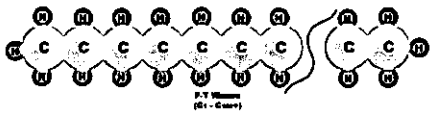
Let's take a look.....

Three Steps in GTL/CTL/BTL Refining to make F-T Fuels

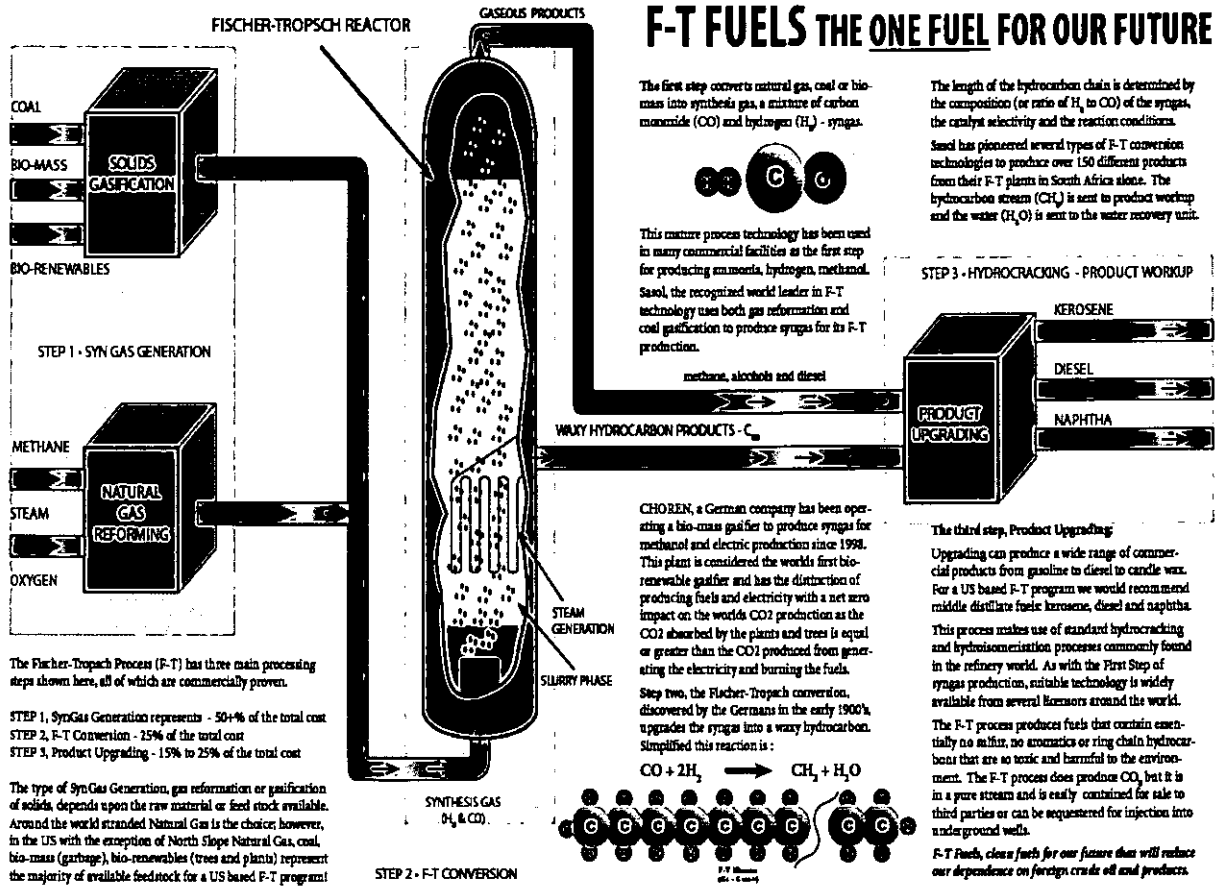
GTL/CTL/BTL Processes use 3 distinct steps to convert a gas or solid into synthetic transport fuels:

- Step 1 - Syn-Gas generation (H_2 & CO)

- Step 2 - The F-T reaction (paraffin wax)



- Step 3 - Product upgrading
  - Kerosene – Diesel – Gasoline - Jet Fuel - Naphtha



F-T FUELS THE ONE FUEL FOR OUR FUTURE

The first step converts natural gas, coal or bio-mass into synthesis gas, a mixture of carbon monoxide (CO) and hydrogen (H_2) - syngas.

This mature process technology has been used in many commercial facilities as the first step for producing ammonia, hydrogen, methanol.

Sasol, the recognized world leader in F-T technology uses both gas reformation and coal gasification to produce syngas for its F-T production.

CHOREN, a German company has been operating a bio-mass gasifier to produce syngas for methanol and electric production since 1998. This plant is considered the worlds first bio-renewable gasifier and has the distinction of producing fuels and electricity with a net zero impact on the worlds CO2 production as the CO2 absorbed by the plants and trees is equal or greater than the CO2 produced from generating the electricity and burning the fuels.

Step two, the Fischer-Tropach conversion, discovered by the Germans in the early 1900's, upgrades the syngas into a waxy hydrocarbon. Simplified this reaction is :

The length of the hydrocarbon chain is determined by the composition (or ratio of H_2 to CO) of the syngas, the catalyst selectivity and the reaction conditions.

Sasol has pioneered several types of F-T conversion technologies to produce over 150 different products from their F-T plants in South Africa alone. The hydrocarbon stream (CH_2) is sent to product workup and the water (H_2O) is sent to the water recovery unit.

The third step, Product Upgrading:

Upgrading can produce a wide range of commercial products from gasoline to diesel to candle wax. For a US based F-T program we would recommend middle distillate fuels: kerosene, diesel and naphtha.

This process makes use of standard hydrocracking and hydroisomerization processes commonly found in the refinery world. As with the First Step of syngas production, suitable technology is widely available from several licensors around the world.

The F-T process produces fuels that contain essentially no sulfur, no aromatics or ring chain hydrocarbons that are so toxic and harmful to the environment. The F-T process does produce CO_2 but it is in a pure stream and is easily contained for sale to third parties or can be sequestered for injection into underground wells.

F-T Fuels, clean fuels for our future that will reduce our dependence on foreign crude oil and products.

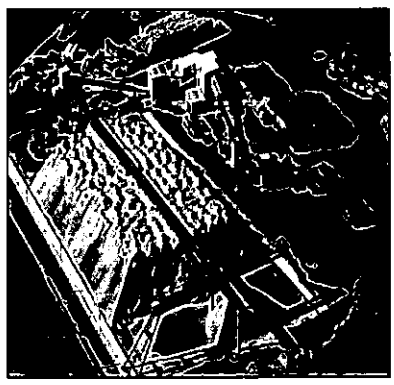
The Fischer-Tropach Process (F-T) has three main processing steps shown here, all of which are commercially proven.

STEP 1, SynGas Generation represents - 50+% of the total cost
STEP 2, F-T Conversion - 25% of the total cost
STEP 3, Product Upgrading - 15% to 25% of the total cost

The type of SynGas Generation, gas reformation or gasification of solids, depends upon the raw material or feed stock available. Around the world stranded Natural Gas is the choice; however, in the US with the exception of North Slope Natural Gas, coal, bio-mass (garbage), bio-renewables (trees and plants) represent the majority of available feedstock for a US based F-T program!

DIFFERENT DOMESTIC NATURAL RESOURCES –THE SAME END FUEL

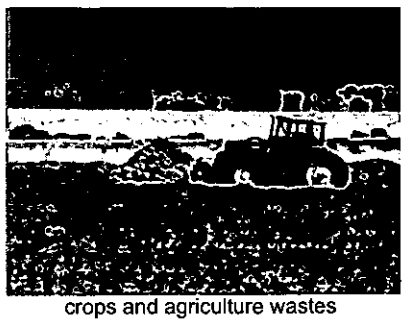
wood - forests - plantations



wood – residue / waste

MSW – garbage - treated human waste

coal



crops and agriculture wastes

identical fuel from all resources

SYNTHETIC DIESEL

F-T DIESEL
AS CLEAN AS CNG

U.S. EPA* APPROVED

NON-TOXIC

ZERO SULFUR

ZERO AROMATICS

70 + CETANE

PM10 ≤ CNG

*EPA Water Docket, EB 57 located at 401 M Street SW Washington DC, 20460 Reference Docket No. W-98-26 in UNOCAL data file 4.A.a.3, Vol 13

WHAT DOES A BELUGA CTL PROJECT NEED TO BE SUCCESSFUL?

- **ATTRACT ONE OF THE WORLDS F-T TECHNOLOGIES TO ALASKA**
  - THERE ARE AT LEAST TWO F-T TECHNOLOGY OWNERS IN THE WORLD CAPABLE OF DESIGNING AND BUILDING A COMMERCIAL SCALE CTL PLANT!
    - **BOTH SASOL AND SHELL ARE BUILDING GTL PLANTS IN QATAR, 3 CTL PLANTS IN CHINA AND 1 IN AUSTRALIA**
    - **BOTH MAY BE PEOPLE CONSTRAINED TO PARTICIPATE IN MORE THAN 1 OR 2 ADDITIONAL CTL PROJECTS**
- ALASKA MUST BE COMPETITIVE WITH OTHER CTL/GTL PROJECTS ACROSS THE WORLD – (NEED *AS GOOD OR BETTER RETURN's*)
  - **(China, Australia, Indonesia, Iran, Qatar, South America)**
- ALASKA MUST BE BETTER THAN OTHER POTENTIAL CTL PROJECTS IN COAL RICH STATES IN THE LOWER 48
  - **Montana, Wyoming, Ohio, North Dakota, Illinois, Indiana, New Mexico, Arizona, Texas, Utah**
- IF ALASKA DOESN'T BUILD THE FIRST CTL PLANT IN THE US, IT MAY HAVE TO WAIT 10 TO 20 YEARS FOR THE NEXT OPPORTUNITY

WHAT DOES THE ALASKA BELUGA CTL PROJECT NEED?

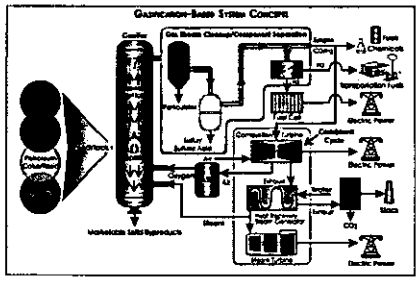
- THERE IS NO QUESTION THAT AT TODAY'S CRUDE OIL PRICES CTL IS ECONOMIC - HOWEVER
- BANKS DON'T LEND MONEY ON $50 CRUDE OIL PRICES
- S&P REQUIRES 1.5 TIMES DEBT COVERAGE AT $28 CRUDE OIL
- THE CURRENT 50¢/GALLON ENERGY CREDIT IN THE TRANSPORTATION BILL - HR-3 IS AN ANSWER - BUT
  - REQUIRES RENEWAL EVERY 5 YEARS
- EXTENDING (GUARANTEEING) THE TERM OF THE F-T ENERGY CREDIT IS ONE SOLUTION
  - Senate Bill 3325 (Coal to Liquids Fuel Promotion Act of 2006)

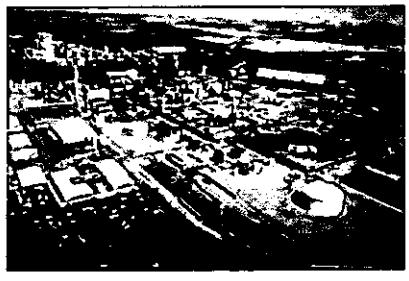
MORE THAN JUST A CTL PROJECT

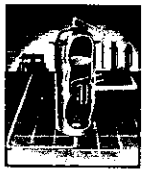
HUNDREDS OF VALUE ADDED BUSINESSES ARE POSSIBLE

VALUE ADDED INDUSTRIES

- The Sasol CTL plants in South Africa produce over 150 different value added products from effluent streams.
- The North Dakota Gasification plant uses the Lurgi process to convert 6 million tons per year of lignite coal to syngas and liquids. The average daily production at Great Plains is about 160 million cubic feet of high quality pipe line natural gas.
- Many by-products are also produced at the plant, including: ammonium sulfate, anhydrous ammonia, carbon dioxide, dephenolized cresylic acid, krypton and xenon gases, liquid nitrogen, naphtha, phenol, and methanol.







SYN-GAS ECONOMICS

THE MARKET FOR SYN-GAS PRODUCTS IN ALASKA IS VERY LIMITED

IT CAN NOT SUPPORT A LARGE SCALE COMMERCIAL GASIFICATION COMPLEX!

Export is the only option

F-T Diesel - world market unlimited

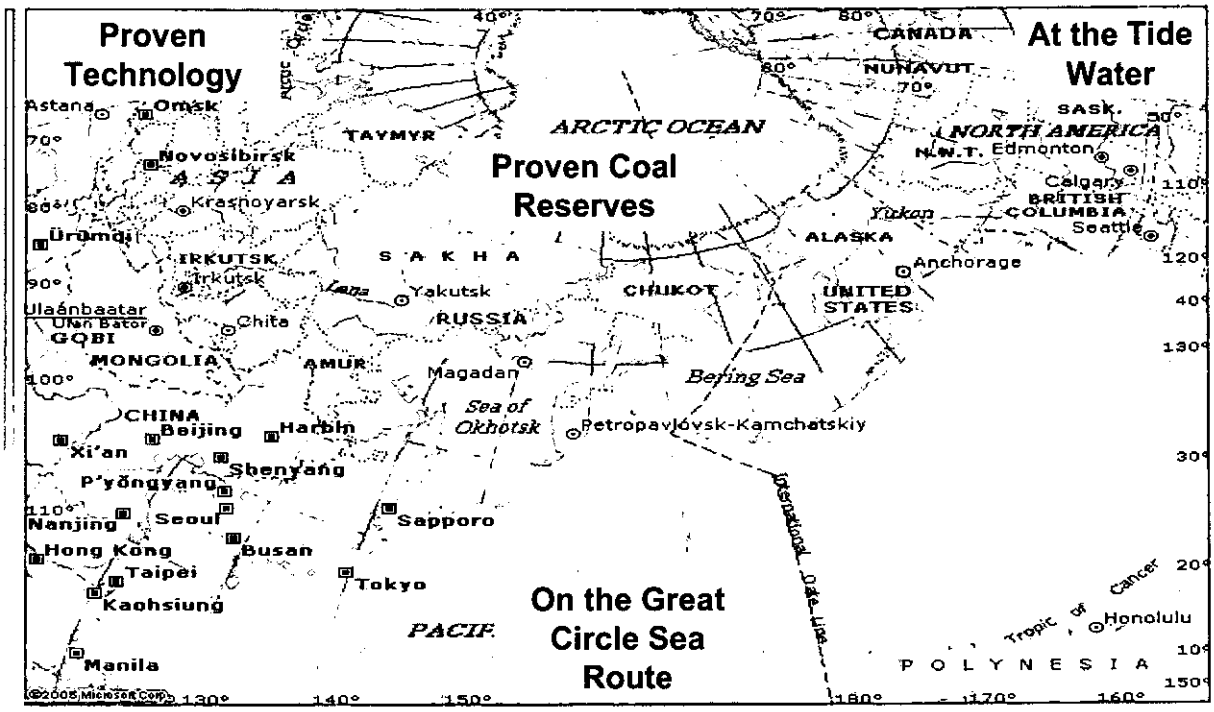
- 16 million barrels per day and growing (245 billion gallons per year)

California Diesel Market

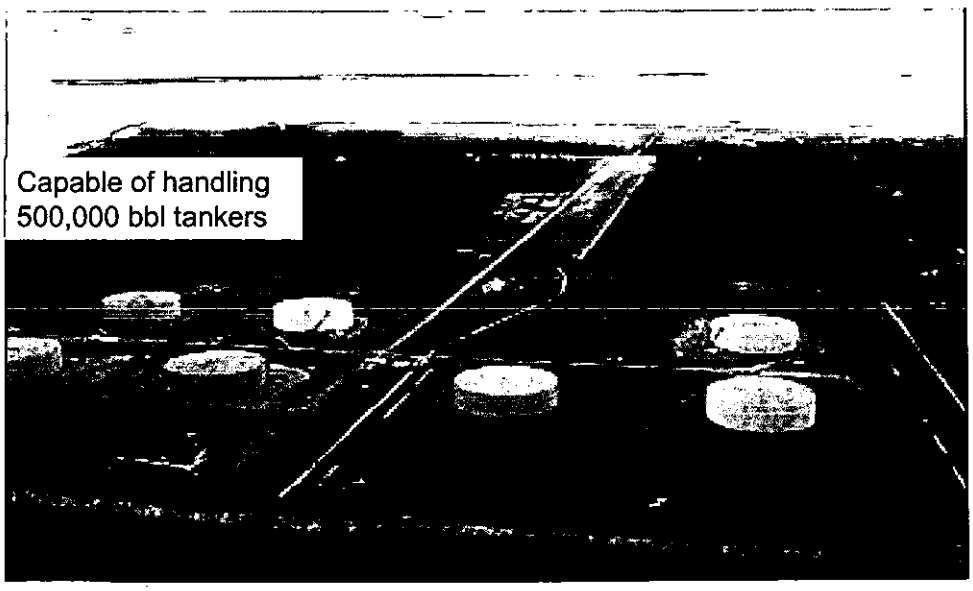
- 420,000 barrels per day and growing (17 million gallons per day)

US WEST COAST THE PRIMARY MARKET FOR ALASKA CTL PRODUCTS

BELUGA CTL PROJECT
NEAR AN EXISTING DEEP WATER EXPORT TERMINAL



DRIFT RIVER EXPORT TERMINAL
COOK INLET, ALASKA



F-T FUEL TECHNOLOGY IS PROVEN BUT IS IT ECONOMIC ?

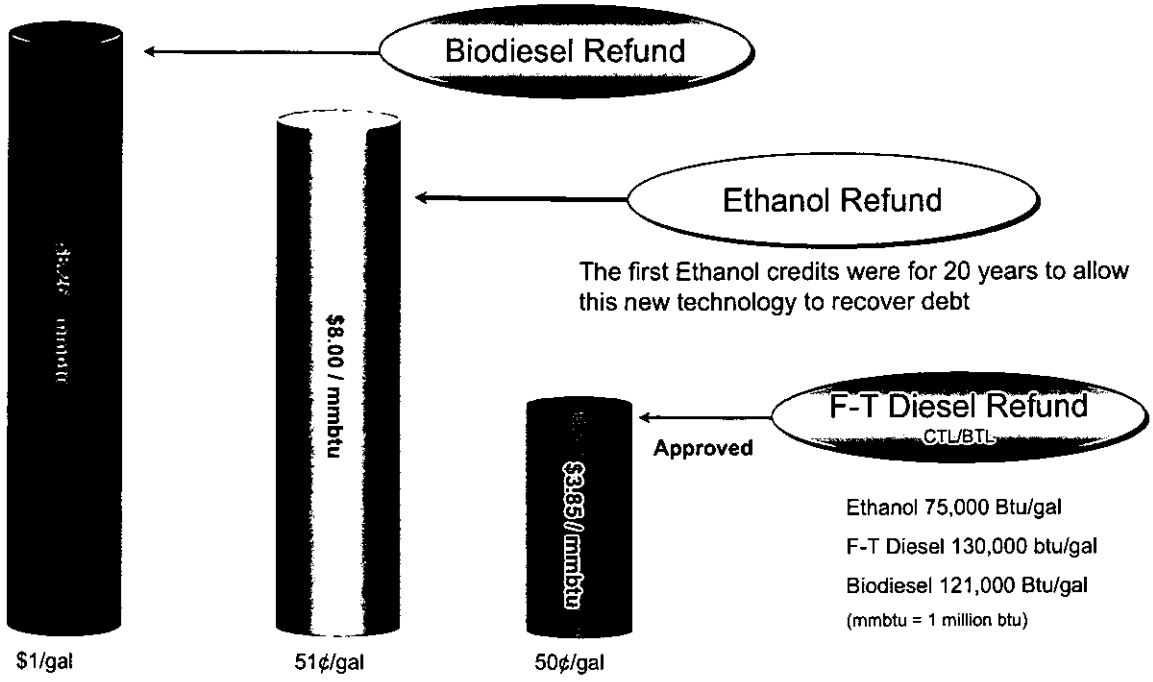
- Over 40 billion gallons of F-T fuels sold to date from BTL CTL and GTL plants around the world – It is proven !
- Over 500,000 bbl/d of new GTL plants under construction or planed for Middle East alone – it is commercial !
- At today's price of crude oil – they are economic !
- Commercial Banks don't lend money on today's crude oil price for projects

FISCHER-TROPSCH SUPPORT

COMPARED TO OTHER "ALTERNATIVE FUELS" IN THE US TODAY

Energy Credits for F-T Diesel (CTL - BTL)
On a $/million btu basis vs Biodiesel & Ethanol

(At the Federal level only)

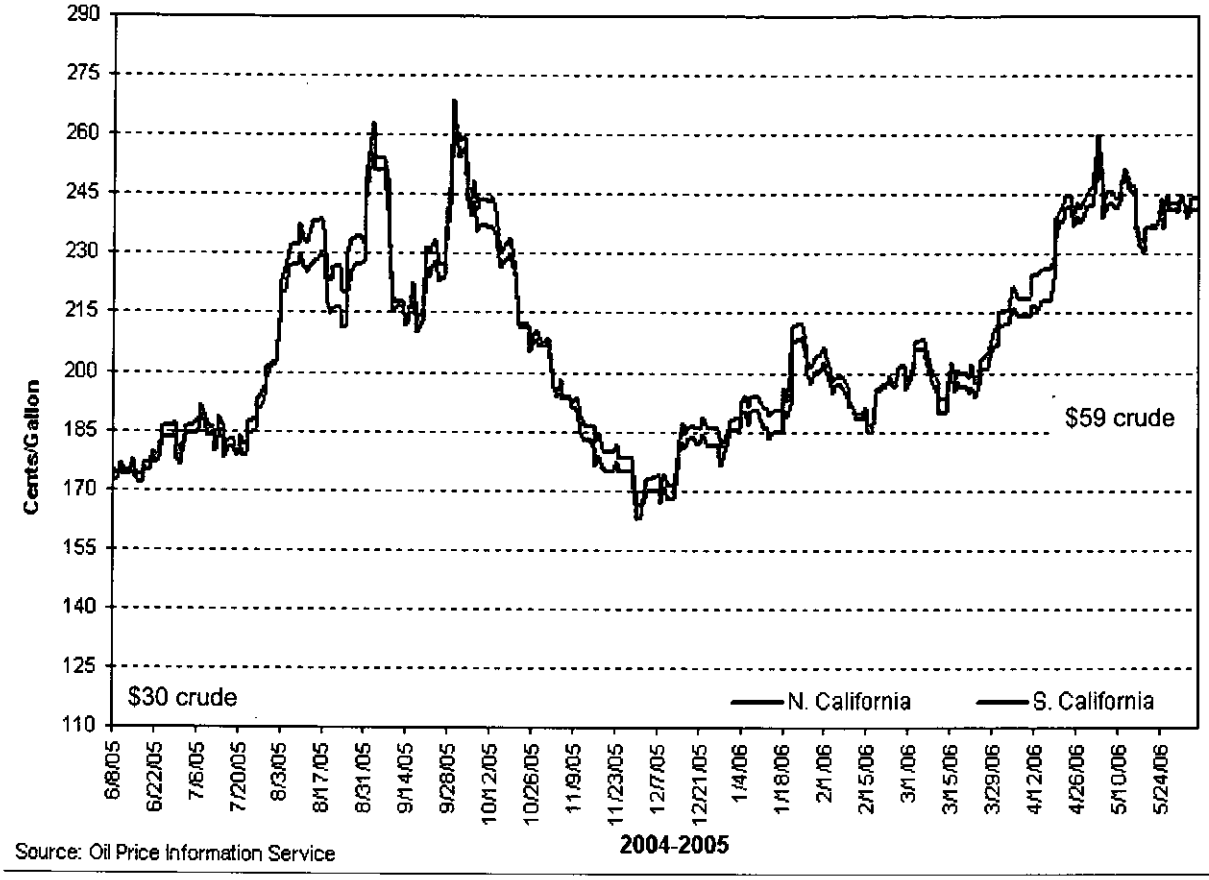


Energy Credits that F-T Diesel receives is less than half the Tax Credit of Biodiesel & Ethanol on a $/million btu basis

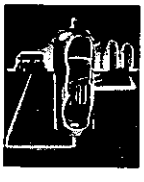
CURRENT FEDERAL SUPPORT FOR THE BELUGA CTL PROJECT

$500 + MILLION / YEAR

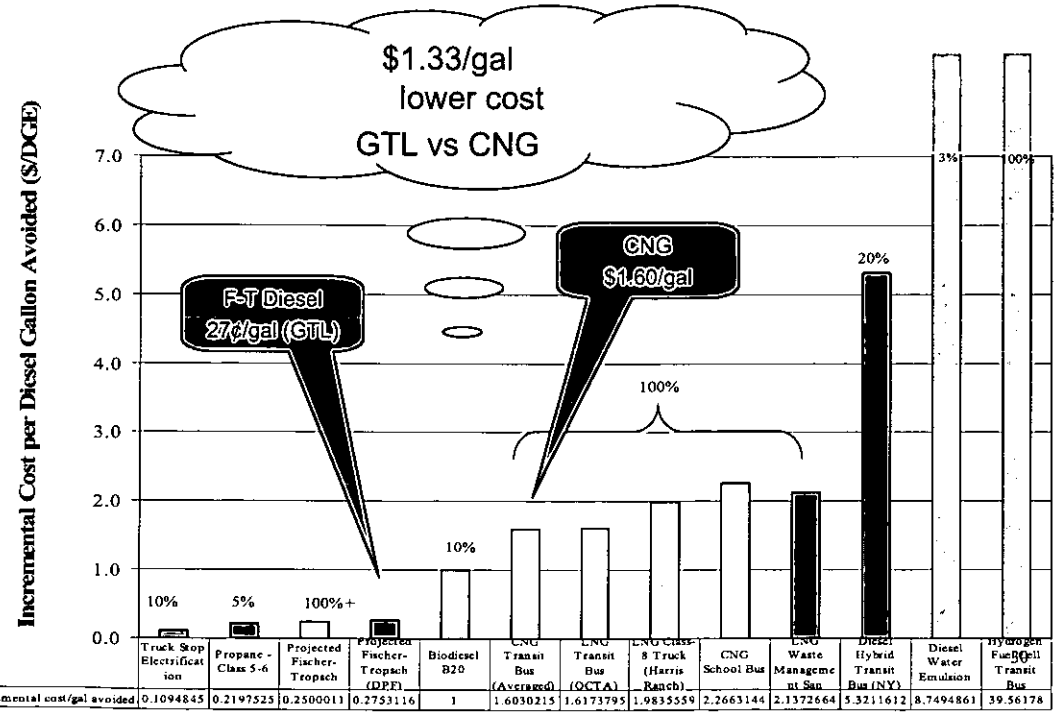
CARB Diesel Fuel Average Rack Prices
(As of 6/5/06)



Source: Oil Price Information Service



California Energy Commission "Cost of Fuel Options Study" for diesel vehicles



Bringing Alaska North Slope Natural Gas to Market

At least three alternatives have been proposed over the years for bringing sizable volumes of natural gas from Alaska's remote North Slope to market in the lower 48 States: a pipeline interconnecting with the existing pipeline system in central Alberta, Canada; a gas-to-liquids (GTL) plant on the North Slope; and a large liquefied natural gas (LNG) export facility at Valdez, Alaska. NEMS explicitly models the pipeline and GTL options [66]. The "what if" LNG option is not modeled in NEMS.

This comparison analyzes the economics of the three project options, based on the oil and natural gas price projections in the *AEO2009* reference, high oil price, and low oil price cases. The most important factors in the comparison include expected construction lead times, capital costs, and operating costs. Others include lower 48 natural gas prices, world crude oil and petroleum product prices, interest rates, and Federal and State regulation of leasing, royalty, and production tax rates. Each option also presents unique technological challenges.

Natural Gas Resources and Production Costs

Natural gas exists either in oil reservoirs as associated-dissolved (AD) natural gas or in gas-only reservoirs as nonassociated (NA) natural gas. Of the 35.4 trillion cubic feet of AD gas reserves discovered on the Central North Slope in conjunction with existing oil fields, 93 percent is located in four fields: Prudhoe Bay (23 trillion cubic feet), Point Thomson (8 trillion cubic feet), Lisburne (1 trillion cubic feet), and Kuparak (1 trillion cubic feet) [67]. Together, those resources (a total of 35.4 trillion cubic feet of AD natural gas reserves) are sufficient to provide 4 billion cubic feet of natural gas per day for a period of 24 years, at an expected average cost of $1.21 per thousand cubic feet (2007 dollars) [68]. The cost estimate is relatively low, because an extensive North Slope infrastructure has been built and paid for with revenues from oil production, and because there is considerably less exploration, development, and production risk associated with known deposits of AD natural gas.

Although additional AD natural gas might be discovered offshore or in the Arctic National Wildlife Refuge (ANWR), most of the "second tier" discoveries in areas to the west and south of the Central North Slope are expected to consist of NA natural gas in gas-only reservoirs. Production costs for gas-only reservoirs are expected to be considerably higher than those for AD natural gas, because they are in remote locations. In addition, the full costs of their development will have to be paid for with revenues from the natural gas generated at the wellhead.

For the first tier of North Slope NA natural gas (29.2 trillion cubic feet) production costs are expected to average $7.91 per thousand cubic feet (2007 dollars). For the second tier, production costs are expected to average $11.03 per thousand cubic feet. Because the cost of producing NA natural gas is substantially greater than the cost of producing AD natural gas, this analysis uses the lower production costs for AD natural gas to evaluate the economic merits of the three facility options examined.

Facility Cost Assumptions

Of the three facility options, the costs associated with an Alaska gas pipeline are reasonably well defined, because they are based on the November 2007 pipeline proposals submitted to the State of Alaska by ConocoPhillips and TransCanada Pipelines, in compliance with the requirements of the Alaska Gasline Inducement Act (AGIA). Costs associated with GTL and LNG facilities are more speculative, based on the costs of similar facilities elsewhere in the world, adjusted for the remote Alaska location and for recent worldwide increases in construction costs (Table 11).

Other key assumptions for all the options analyzed include natural gas feedstock requirements, natural gas heating values, characteristics of the operations, State and Federal income tax rates, and the time required for planning, obtaining required permits, and constructing the facilities. Key assumptions that are unique to each option include the following: for the Alaska pipeline option, the tariff rate for the existing pipeline from Alberta to Chicago and the spot price for natural gas in Chicago; for the LNG facility option, capital and operating costs, including the cost of building a pipeline from the North Slope to

Table 11. Assumptions for comparison of three Alaska North Slope natural gas facility options

Assumption	Pipeline option	LNG option	GTL option
Natural gas conversion efficiency (percent)	*94*	*80*	*60*
Capital costs (billion 2007 dollars)	*27.6*	*33.9*	*57.5*
Operating costs (million 2007dollars per year)	*263.0*	*392.9*	*894.3*

liquefaction and storage facilities in Valdez, and the value of LNG delivered in Asia and Valdez; and for the GTL facility option, the time required to conduct tests to determine whether the Trans Alaska Pipeline System (TAPS) should be operated in batch or commingled mode with GTL, the production level and mix of product, the oil pipeline tariff and tanker rates to U.S. West Coast refiners, and the price of GTL products relative crude oil prices. The costs of testing and possibly converting TAPS into a batching crude/product pipeline are not included for the GTL option.

Discussion

To compare the economics of the three options, an internal rate of return (IRR) was calculated for each alternative, based on the projected average price of light, low-sulfur crude oil and the projected average price of natural gas on the Henry Hub spot market in the *AEO2009* reference, high oil price, and low oil price cases for the 2011-2020 and 2021-2030 periods (Table 12). The IRR calculations (Figures 20 and 21) assume that the average prices for the period in which a facility begins operation will persist throughout the 20-year economic life of the facility. Projected crude oil prices show considerably more variation across the cases and time periods than do Henry Hub natural gas prices, affecting the relative economics of the three options. In 2030, in the low and high oil price cases, crude oil prices are $50 and $200 per barrel, respectively, and natural gas prices are $8.70 and $9.62 per million Btu, respectively (all prices in 2007 dollars).

The *AEO2009* projections show wide variations in oil prices, which are set outside the NEMS framework to reflect a range of potential future price paths. For natural gas prices, variations across the cases are smaller, reflecting the feedbacks in NEMS that equilibrate supply, demand, and prices in the natural gas market model. Natural gas price increases are held in check by declines in demand (especially in the electric power sector) and increases in natural gas drilling, reserves, and production capacity. Similarly, natural gas price declines are held in check by increases in demand and decreases in drilling, reserves, and production capacity. Natural gas prices are also restrained because only a small portion of the natural gas resource base is projected to be consumed through 2030, and the marginal cost of natural gas supply increases slowly.

Table 12. Average crude oil and natural gas prices in three cases, 2011-2020 and 2021-2030

	2011-2020	2021-2030
Oil price (2007 dollars per barrel)		
Reference	*107.32*	*123.26*
High oil price	*154.24*	*193.25*
Low oil price	*51.61*	*50.31*
Natural gas price (2007 dollars per million Btu)		
Reference	*7.04*	*8.21*
High oil price	*7.52*	*8.50*
Low oil price	*6.24*	*7.88*

As indicated in Figures 20 and 21, IRRs for the pipeline option are sensitive to natural gas price levels, whereas IRRs for the GTL and LNG options are more sensitive to crude oil prices. Consequently, from 2021 through 2030, IRRs for the pipeline option vary by 15 to 17 percent across the three price cases, whereas those for the GTL and LNG options vary by 4 to 24 percent and 7 to 27 percent, respectively. On that basis, the pipeline option would be considerably less

Figure 20. Average internal rates of return for three Alaska North Slope natural gas facility options in three cases, 2011-2020 (percent)

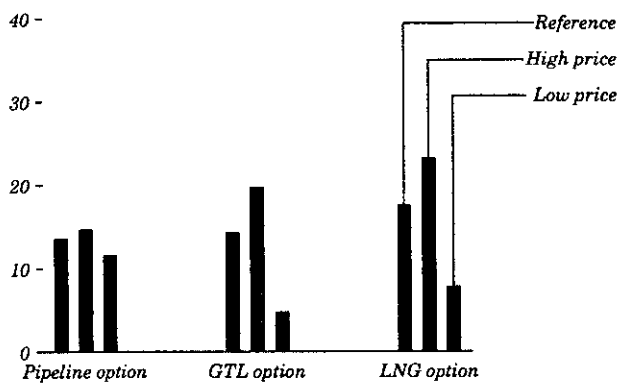
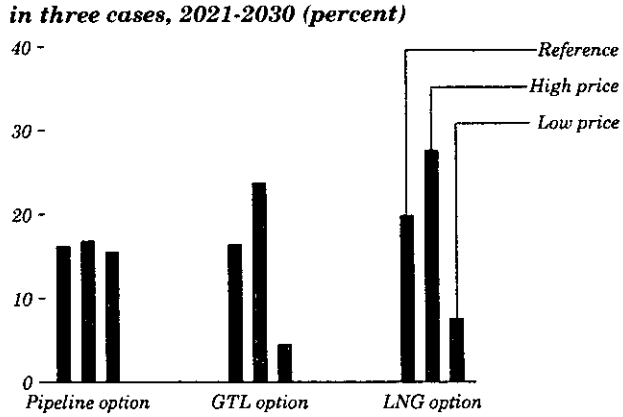


Figure 21. Average internal rates of return for three Alaska North Slope natural gas facility options in three cases, 2021-2030 (percent)



risky than either the GTL or LNG option. Also, the pipeline would involve significantly less engineering, construction, and operation risk than either of the other options.

The potential viability of an Alaska natural gas pipeline is bolstered by the fact that British Petroleum (BP), ConocoPhillips (CP), and TransCanada Pipelines already have committed to building a pipeline. All three have extensive experience in building and financing large-scale energy projects, and both BP and CP have access to substantial portions of the less expensive North Slope AD natural gas reserves. Given that institutional support, along with the prospect for adequate rates of return, the natural gas pipeline option appears to have the greatest likelihood of being built.

Because the GTL option does not include the cost of testing and adapting the existing TAPS oil pipeline to GTL products—which would require third-party cooperation and likely cost reimbursement—the GTL rates of return are overstated. In addition, the GTL results include considerable uncertainty with regard to capital and operating costs and future environmental constraints on GTL plants. Prospects for Alaska GTL facilities are further clouded by the current absence of project sponsors.

Of the three options, an LNG export facility shows the highest rates of return in the reference and high price cases; however, it shows low rates of return in the low price case. The project risk associated with the LNG option is considerably less than that for the GTL option but greater than for the pipeline option. The LNG option is further undermined by the fact that there are large reserves of stranded natural gas elsewhere in the world that have a significant competitive advantage both because of their proximity to large consumer markets and because they would not require construction of an 800-mile supply pipeline. Although there is definite interest in the LNG export option in Alaska, current advocates of the project have not yet secured letters of intent from potential buyers to purchase the LNG, nor do they have ownership of low-cost AD reserves, extensive experience in the management of large-scale projects, or strong financial backing. Finally, if oil shale deposits in the rest of the world turn out to be as rich in natural gas as those in the United States, worldwide demand for LNG could be reduced considerably from the levels that were expected just a few years ago.

Other Issues

The analysis described here focused primarily on the relative economics and risks associated with each of three options for a facility to bring natural gas from Alaska's North Slope to market. There are, in addition, a number of other issues that could be important in determining which facility option could proceed to construction and operation, three of which are described briefly below.

Resolving ownership issues for the Point Thomson natural gas condensate field lease. The State of Alaska has revoked the Point Thomson lease from the original leaseholders. Point Thomson holds approximately 8 trillion cubic feet of recoverable natural gas reserves, and without that supply, the existing North Slope AD reserves would be insufficient to supply a natural gas pipeline over a 20-year lifetime. The 35.4 trillion cubic feet of existing AD natural gas reserves on the Central North Slope includes Point Thomson's 8 trillion cubic feet, and without those reserves only 27.4 trillion cubic feet of North Slope gas reserves would be available, providing just 18.8 years of supply for a 4 billion cubic feet per day facility. As long as the ownership issue of the Point Thomson lease remains unresolved, the possibility of pursuing construction of any of the three options is diminished.

Obtaining permits for an Alaska natural gas pipeline in Canada. The pipeline option could encounter significant permitting issues in Canada, similar to those that have already been encountered by the Mackenzie Delta gas pipeline, whose construction has been significantly delayed as the result of a failure to secure necessary permits. Because there have been no filings for Canadian permits by any Alaska gas pipeline sponsor, the severity of this potential problem cannot be determined.

Exporting Alaska LNG to foreign consumers. Some parties in the United States have called for a halt to current exports of LNG from Alaska to overseas markets. If Alaska were prohibited from exporting LNG to overseas consumers, the financial risk associated with any new Alaska LNG facility would increase significantly, because the financial viability of an LNG facility would be tied solely to lower 48 natural gas prices, which are projected to be considerably lower than overseas natural gas prices.

Shipping GTL products through TAPS. The joint ownership structure of TAPS could prevent a

minority owner from using the pipeline to ship GTL from the North Slope south to Valdez and on to market.

Conclusion

The *AEO2009* price cases project greater variance in oil prices than in natural gas prices. If those cases provide a reasonable reflection of potential future outcomes, then the pipeline option in this analysis would be exposed to less financial risk than the GTL and LNG options. Additionally, it is the only option that already has the commitment of energy companies capable of financing and constructing such a large, capital-intensive energy facility. The balance of the factors evaluated here points to an Alaska natural gas pipeline as being the most likely choice for bringing North Slope natural gas to market.

Endnotes

66. The GTL option is represented in NEMS in the form of facilities with capacities of 34,000 barrel per day that can be added incrementally when oil and petroleum product prices are sufficiently high to make their operation profitable.
67. Alaska Department of Natural Resources, Division of Oil and Gas, *Alaska Oil and Gas Report 2007* (Anchorage, AK, July 2007), Table III.1, p.-2, web site www.dog.dnr.state.ak.us/oil/products/publications/annual/report.htm.
68. K.W. Sherwood and J.D. Craig, *Prospects for Development of Alaska Natural Gas: A Review as of January 2001* (Anchorage, AK: U.S. Department of Interior, Minerals Management Service, Resource Evaluation Office), Chapters 4 and 5, web site www.mms.gov/alaska/re/natgas/akngas2.pdf. Resource recovery costs were updated for this analysis, to reflect the escalation of drilling costs over time.

Bringing Alaska North Slope Natural Gas to Market

Introduction

At least three alternatives have been proposed over the years for bringing sizeable volumes of remote Alaska North Slope natural gas to market. This discussion analyzes those alternatives, namely (1) a gas pipeline interconnecting with the existing pipeline system in central Alberta Canada, (2) a gas-to-liquids (GTL) plant on the North Slope, and (3) a large liquefied natural gas (LNG) export facility at Valdez, Alaska.

The National Energy Modeling System (NEMS), which produces the energy projections published in the *Annual Energy Outlook*, explicitly models the pipeline and GTL options.[1] This article presents an additional 'what if' option and analyzes potential economic value of each of the three alternatives under the oil and natural gas price projections in the reference, high, and low oil price cases of the *Annual Energy Outlook*.

This comparison analyzes the economics of the three project options looking at their expected construction lead times, and capital and operating costs of each option. Considerable uncertainties exists, however, regarding these costs and lead times and with respect to future lower 48 natural gas prices, world crude oil and petroleum product prices, interest rates, and Federal and State regulation of leasing, royalty, and production tax rates. Each facility also presents unique technological challenges, further adding to the uncertainty.

To ensure consistent treatment across the alternatives, one common assumption is that each facility would be based on a North Slope natural gas production level of 4 billion cubic feet (Bcf) per day and that each facility type has a minimum economic lifetime of 20 years. A 20-year facility life, relying on 4 Bcf per day, requires a total dedication of 29.2 trillion cubic feet (Tcf) of North Slope natural gas reserves.

Alaska North Slope Natural Gas Resources and Production Costs

Natural gas exists either in oil reservoirs as associated-dissolved (AD) natural gas or in gas-only reservoirs as non-associated (NA) natural gas. Of the 35.4 Tcf of AD gas reserves discovered on the Central North Slope in conjunction with existing oil fields, 93 percent is located in 4 fields: Prudhoe Bay (23 Tcf), Point Thomson (8 Tcf), Lisburne (1 Tcf), and Kuparak (1 Tcf).[2] These 35.4 Tcf of AD gas reserves are sufficient to serve a 4 Bcf facility for 24 years.

Producing the existing 35.4 Tcf of AD gas reserves is expected to cost an average of $1.21 per thousand cubic feet (Mcf) (2007 dollars).[3] This relatively low AD production

[1] NEMS represents the GTL option in the form of 34,000 barrel per day facilities that can be added incrementally when oil and petroleum product prices are sufficiently high to make these facilities profitable relative to the technological and market risks facing GTL.

[2] Source for ANS associated-dissolved gas reserves: Alaska Department of Natural Resource, *Alaska Oil and Gas Report*, July 2007, Table III.1, page 3-2.

[3] U.S. Department of Interior, Minerals Management Service, "Prospects for Development of Alaska Natural Gas: A Review as of January 2001," Resource Evaluation Office, Anchorage, Alaska, Chapters 4 and 5. NA gas costs reflect exploration and development drilling, completion, and production costs at a

cost is because an extensive North Slope infrastructure has been built and paid for by oil production, and because there is considerably less exploration, development, and production risk associated with these known AD gas deposits.

Although additional AD natural gas might be discovered offshore or in the Arctic National Wildlife Refuge (ANWR), most of the North Slope natural gas expected to be discovered west and south of the Central North Slope is NA gas in gas-only reservoirs. The cost of producing these gas-only reservoirs is expected to be considerably higher than AD gas because of their remote location and because the full cost of development must be paid for by the natural gas revenues generated at the wellhead. The first tier of North Slope NA gas (29.2 Tcf) is expected to cost $7.91 per Mcf (2007 dollars) to produce, while the second tier of NA gas is expected to cost $11.03 per Mcf.[4] Because the NA natural gas production cost is substantially greater than the estimated AD gas production cost, this analysis will focus on the relative economic merits of the three facility options only in the context of the less expensive AD gas.

Facility Cost Assumptions

Of the three facility options, the costs associated with an Alaska gas pipeline are well defined, based on the November 2007 pipeline proposals submitted in compliance with the Alaska Gasline Inducement Act (AGIA) requirements by ConocoPhillips and TransCanada Pipelines to the State of Alaska. Costs associated with gas-to-liquids and liquefaction facilities are more speculative, and are based on similar facilities found elsewhere in the world, adjusted for the remote Alaska location and for recent world-wide construction cost increases (Table 1).

Table 1
Alaska North Slope Facility Costs and Operating Parameter Assumptions
(Costs are in 2007 dollars)

	Gas Pipeline to Alberta	LNG Export Facility	GTL Facility
Gas Conversion Efficiency 1/	94%	80%	60%
Capital Costs (Billion dollars) 2/	$27.6	$33.9	$57.5
Operating Costs (Million $ per year) 3/	$263.0	$392.9	$894.3

1/ LNG facility efficiency does not include any LNG tanker losses while in transit; pipeline efficiency based on AGIA averages; LNG and GTL losses based on levels cited in technical literature Source: Bipin Patel, Foster Wheeler Energy Limited, "Gas Monetisation: A Techno-Economic Comparison of Gas-To-Liquid and LNG," 2005.

2/ Each option's capital cost includes $6.5 billion in capital costs to pay for gas gathering and treatment facilities. Gathering and treatment costs based on ConnocoPhilips AGIA proposal costs. LNG capital costs based on liquefaction plant estimates provided by Robert Baron, a DOE/Fossil Energy consultant, and

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reasonable rate of return, but do not include gas gathering and processing costs, which are included in the capital and operating costs of each of the three facilities. The AD gas costs represent the cost of pumping the natural gas out of the reservoir to the surface, periodically reworking the wells, and drilling some infill wells, plus a reasonable rate of return for these activities, but do not include gathering and processing costs.

[4] Ibid. Each tier of 29.2 Tcf is based on the gas requirements of a 4 Bcf per day facility operating over a 20-year economic life.

prorated AGIA gas pipeline costs based on the mileage from the North Slope to Valdez, and escalated by 20% to reflect the cost of building over the Alaska Range mountains in a seismically active zone. GTL North Slope capital cost based on $110,000 per daily stream barrel as per the Petroleum News article, "Legislators told GTL a no-go for ANS gas," March 11, 2007.
3/ Operating costs include labor, maintenance, administrative overhead, etc. but do not include natural gas feedstock costs. Pipeline operating costs are based on EIA's NGTDM model values. LNG operating costs are based on study by Robert Baron, consultant for DOE/FE Study of LNG and GTL costs, 2006. GTL operating costs are based on EIA's INGM model.

Other key assumptions for each facility type include:

- All Facility Types:
  - The natural gas feedstock requirement is 4 Bcf per day,
  - The natural gas heating value is 1,099 Btus per cubic foot[5],
  - In the first year of operation, a project produces at 50 percent of capacity at 60 percent of annual operating cost, and
  - The State and Federal income tax rates collectively are 38 percent.

- Alaska Gas Pipeline:
  - The Alberta to Chicago gas pipeline tariff rate is $0.70/MMBtu (2007 dollars)[6],
  - Chicago spot natural gas prices are approximately $0.10/MMBtu less than Henry Hub spot prices[7], and
  - The pipeline takes 9 years to plan, permit, and construct, with most of the construction costs incurred during the last 4 years.

- LNG Facility:
  - Capital and operating costs include the cost of building a gas pipeline from the North Slope to the liquefaction and storage facilities in Valdez, but do not include the cost of tankers to ship LNG to customers,
  - LNG delivered in Asia is valued at 85 percent of the low-sulfur, light crude oil price,[8]
  - The LNG at Valdez is valued at 85 percent of the delivered LNG price to account for LNG shipping costs, and
  - The LNG facility, including the gas pipeline from the North Slope to Valdez, takes 5 years to plan, permit, and construct.

- GTL Facility:
  - GTL facility costs do not include any costs to test and possibly convert the Trans Alaska Pipeline System (TAPS) into a batching crude/product pipeline[9],

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[5] Average of ConnocoPhilips and TransCanada AGIA application.
[6] Current value contained in NGTDM module.
[7] Based on historical average natural gas price differential between Alberta and Chicago.
[8] Source: Alaska Gasline Port Authority, "Application for the All-Alaska Gas Line Project," submitted on November 30, 2007 to the State of Alaska as a project submission for the Alaska Gasline Inducement Act, Fairbanks, Alaska, pages 158 to 164.
[9] Testing and conversion costs are unknown at the present time; no study proposals have been made.

- Prior to construction of a GTL facility, 3 years would be required to conduct tests to determine whether TAPS should be operated in batch or commingled mode with GTLs[10],
- Produces about 460,000 barrels per day of petroleum products of which 30 percent is naphtha and 70 percent is distillate (diesel)[11],
- A $4.87/bbl oil pipeline tariff rate[12] and a $3.50/bbl tanker rate[13] to U.S. West Coast refiners are assumed for GTL petroleum products,
- GTL products are collectively priced at 120 percent of the West Texas Intermediate crude oil price[14], and
- The GTL facility takes 5 years to plan, permit, and construct due to a harsh site environment and difficult logistics.

Discussion

To compare the economic attractiveness of each of the three options, internal rates of return (IRR) were calculated for each alternative, based on the average projected prices of light, low-sulfur crude oil and Henry Hub spot natural gas (Table 2) for the *AEO 2009* reference, high oil price, and low oil price cases during two periods spanning 2011 through 2020 and 2021 through 2030 (Figure 1). These IRR calculations assumed that the average price over each time period persists during the entire 20-year economic life of the facility. Projected crude oil prices show considerably more variation across the cases and time periods than do Henry Hub gas prices and can flow through to project outcomes. In 2030, crude oil prices range from $50 dollars per barrel (2007 dollars) in the low oil price case to $200 per barrel in the high oil price case, while gas prices range from $8.70 per million Btu to $9.62 per million Btu across the same oil price cases.

Table 2
Average Projected Crude Oil and Natural Gas Prices
For Periods Spanning 2011-2020 and 2021-2030
By *Annual Energy Outlook 2009* Oil Price Case

		2011-2020	2021-2030
Light, Low-Sulfur Crude Oil Price	Reference Case	$107.32	$123.26
(Dollars Per Barrel)	High Oil Price Case	$154.24	$193.25
	Low Oil Price Case	$51.61	$50.31
Henry Hub Spot Natural Gas Price	Reference Case	$7.04	$8.21
(Dollars per Million Btu)	High Oil Price Case	$7.52	$8.50
	Low Oil Price Case	$6.24	$7.88

The AEO2009 oil price projections show a large variation in oil prices, which are set outside of the NEMS framework to reflect the full range of potential future oil prices. In contrast to oil, a smaller variation in natural gas prices is projected across all the NEMS

[10] Source: University of Alaska Fairbanks, "Operational Challenges in Gas-to-Liquid (GTL) Transportation Through Trans Alaska Pipeline System (TAPS)," March 2007, page xii.
[11] Source: Alaska Natural Gas Development Authority, "Alaska Natural Gas Needs and Market Assessment: 2008 Update of the Industrial Sector," June 2008, page 1.
[12] FERC No. 13 tariff rate for TAPS effective January 1, 2008.
[13] Transportation rate contained in the NEMS Petroleum Marketing Module.
[14] Based on historical averages.

cases, including the oil price cases. The smaller variation in natural gas prices results from the NEMS natural gas market feedbacks that equilibrate supply, demand, and price.

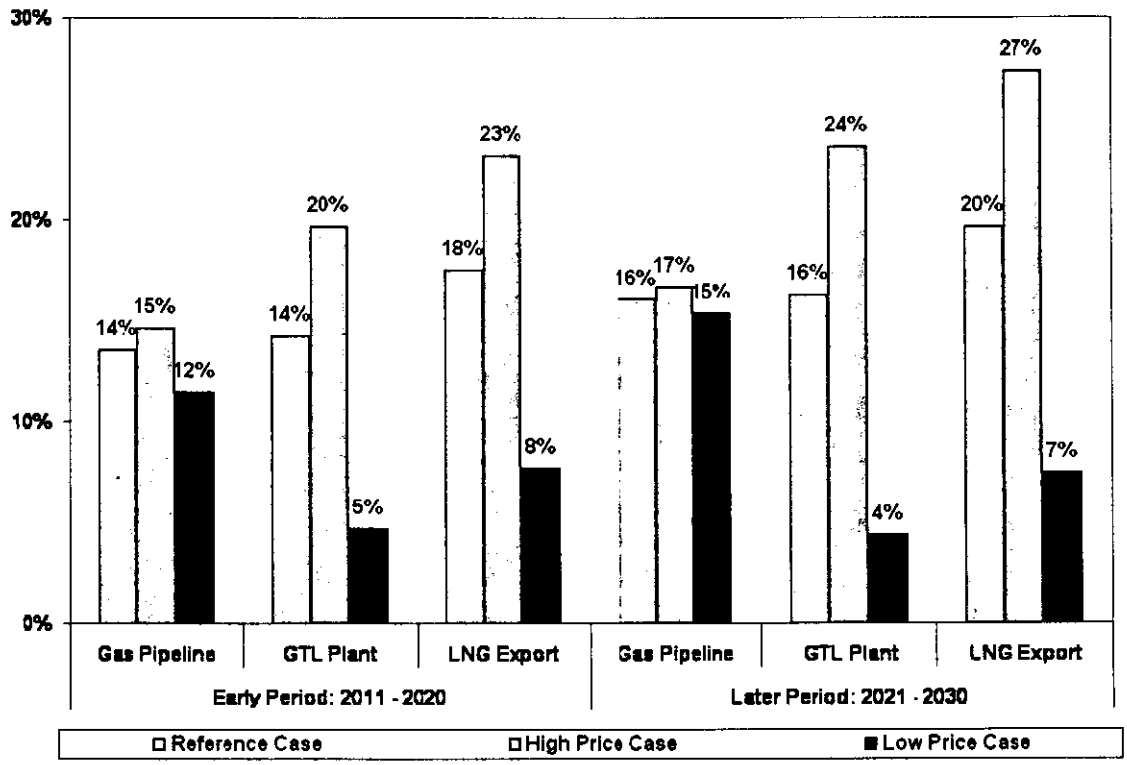
Within NEMS, natural gas price increases are held in check by declining natural gas demand (especially within the electric power sector) and by increasing natural gas drilling, reserves, and productive capacity. Similarly, natural gas price declines are held in check by an increasing gas demand and by decreasing gas drilling, reserves, and productivity capacity. Natural gas prices are also restrained by the fact that only a the small proportion of the gas resource base is consumed through 2030 and that the marginal cost of gas supply increases slowly in the initial portion of the gas supply curve.

Gas pipeline IRR results are sensitive to gas prices while GTL and LNG IRR results are sensitive to crude oil prices (Figure 1). During the 2021 through 2030 period, the small variability in projected gas prices results in pipeline rates of return ranging between 15 and 17 percent, while the large variability in projected oil prices results in GTL and LNG rates of return ranging between 4 to 24 percent and 7 to 27 percent, respectively. If the projected range in oil and gas prices is a reasonable expectation of potential future outcomes, then the gas pipeline option is considerably less risky than either the GTL or the LNG option. The gas pipeline also has significantly less engineering, construction, and operation risk than either of the other options.

The viability of an Alaska gas pipeline is bolstered by the fact that British Petroleum (BP), ConocoPhillips (CP), and TransCanada Pipelines have each committed to building a gas pipeline. These parties have extensive experience in building and financing large scale energy projects, while BP and CP have access to a substantial portion of the less expensive North Slope AD gas reserves. Given the institutional support and the prospect for adequate rates of return, a gas pipeline presently has the greatest likelihood of being built.

Because the GTL option does not include the cost of testing and adapting the existing TAPS oil pipeline to GTL products which would require third-party cooperation and likely cost reimbursement, the GTL rates of return are overstated. GTL results are also burdened by considerable uncertainty regarding capital and operating costs and any future environmental constraints that might be imposed on such plants. Prospects for Alaska GTL facilities are further hindered by the absence of project sponsors at the present time.

Figure 1
2011 – 2020 and 2021 - 230 Average Internal Rates of Return
For the Three North Slope Alaska Facility Options
Using North Slope Associated-Dissolved Wellhead Natural Gas Feedstock
For the *Annual Energy Outlook 2009* Oil Price Cases



Of the three facility options, an LNG export facility presents the best rates of return in the reference and high oil price cases. However, this option earns low rates of return in the low oil price case. The project risk associated with the LNG export option is considerably less than for GTL but greater than for the pipeline.

The financial viability of an Alaska North Slope LNG export option is further undermined by the fact that there are large stranded gas reserves elsewhere in the world that enjoy a significant competitive advantage both by their proximity to large consumer markets and by not being burdened with having to build an 800-mile Arctic supply pipeline. These stranded foreign gas reserves would be developed for LNG export at a significantly lower cost than those located in the Alaska North Slope, thereby making the potential future demand for Alaska North Slope LNG much more speculative and uncertain.

Even though there is a definite interest in the LNG export option in Alaska, the current project advocates have neither secured letters of intent from potential buyers to purchase LNG nor do they have (1) ownership of the low-cost AD gas reserves, (2) extensive large-scale project management experience, or (3) strong financial backing.

Other Issues

This analysis focused primarily on the relative economics and risks associated with each North Slope facility option. However, there are a number of non-economic issues that could hinder or preclude the construction of these facilities. The most significant of these issues include:

- Revocation of the Point Thomson gas-condensate field lease. The State of Alaska has revoked the Point Thomson lease from the original leaseholders. Point Thomson holds approximately 8 trillion cubic feet of recoverable gas reserves. Absent the availability of the Pt. Thomas gas, the existing North Slope AD gas reserves are insufficient to supply a gas pipeline over a 20-year lifetime.[15] As long as the ownership issue of the Point Thomson lease remains unresolved, the possibility of pursuing construction of any of the three options is unlikely.
- Obtaining permits for an Alaska gas pipeline in Canada. The gas pipeline option could encounter significant permitting issues in Canada, similar to those that have already been encountered by the Mackenzie Delta gas pipeline, whose construction has been significantly delayed as a result of being unable to secure all necessary permits. Because there have been no filings for Canadian permits by any Alaska gas pipeline sponsor, the severity of this potential problem is indeterminate at this time.
- Exporting Alaska LNG to foreign consumers. Some parties within the United States have called for a halt to the current LNG exports from Alaska to overseas markets. If Alaska were prohibited from exporting LNG to overseas consumers, then the financial risk associated with any new Alaska LNG facility would increase significantly because the financial viability of an LNG facility would be tied to lower 48 natural gas prices, which are projected to be considerably lower than overseas natural gas prices.
- Shipping GTL products through the TransAlaska oil pipeline system (TAPS). The joint ownership structure of TAPS could prevent a minority owner from utilizing TAPS for shipping petroleum liquids from their GTL plant on the North Slope southward to Valdez for movement to PADD 5 or elsewhere.

Conclusions

The AEO2009 oil price cases project greater variation in oil prices than in natural gas prices. If these scenarios are a reasonable reflection of potential future outcomes, then the natural gas pipeline would be exposed to less financial risk than the GTL and LNG facilities. The gas pipeline also has significantly lower engineering, construction, and operation risk than the GTL and LNG facilities. Finally, only the gas pipeline has the commitment of energy companies that are capable of financing and constructing such a large, capital-intensive energy facility. So the balance of the factors evaluated among the

[15] The 35.4 Tcf of existing natural gas reserves includes Pt. Thomson's 8 Tcf. Without the Pt. Thomson gas reserves, only 27.4 Tcf of North Slope gas reserves would be available for only 18.8 years for a 4 Bcf per day facility.

Beluga Coal Gasification Feasibility Study

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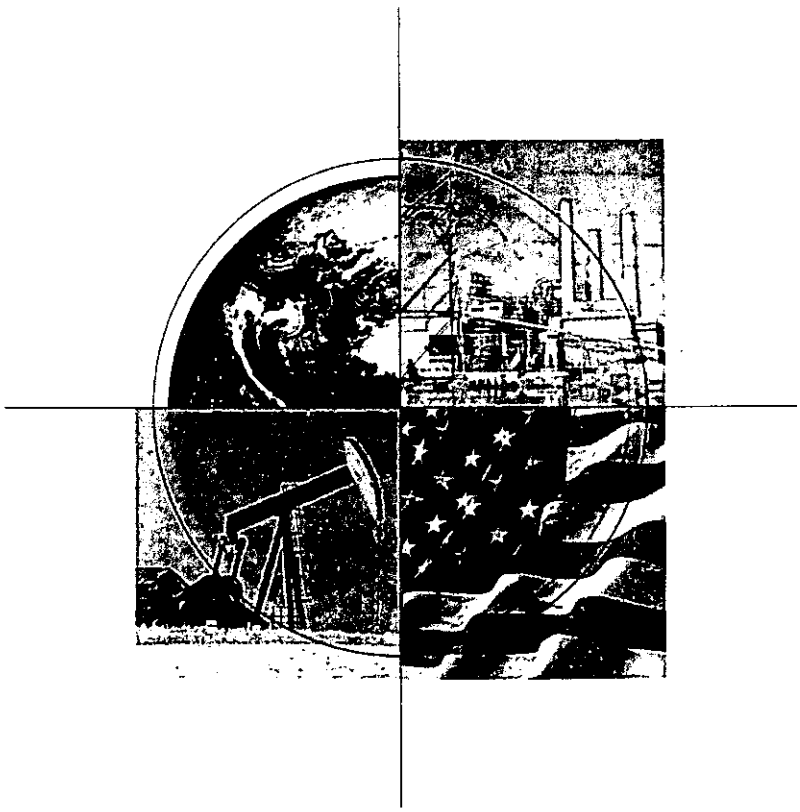

Phase I Final Report

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Beluga Coal Gasification Feasibility Study

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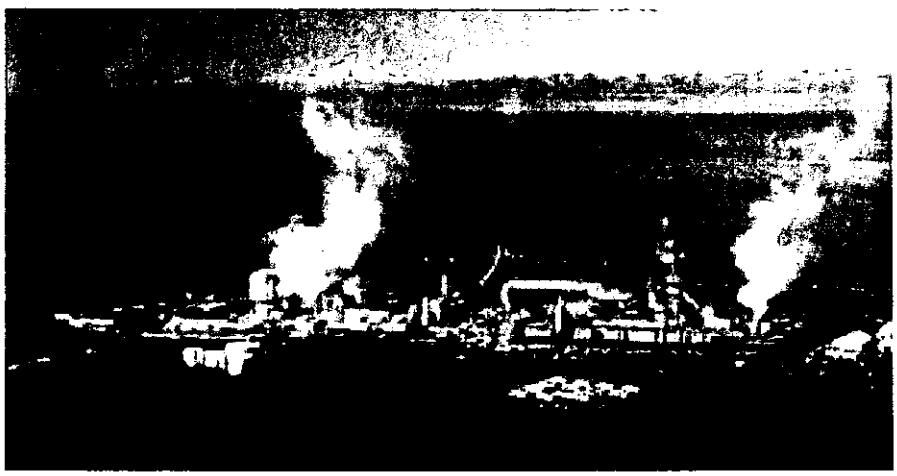

Agrium Kenai Nitrogen Operations Plant
Nikiski, Alaska

The Agrium fertilizer plant has been experiencing shortages of natural gas for feedstock and winter shutdowns have occurred. This study focused on evaluating the feasibility of the gasification of Beluga coal, shipped from the Chuitna Mine located across the Cook Inlet, to produce synthetic gas to be used by Agrium. The coal gasification facility would be located at the Agrium site.

BELUGA COAL GASIFICATION FEASIBILITY STUDY

Executive Summary

The objective of the Beluga Coal Gasification Feasibility Study was to determine the economic feasibility of developing and siting a coal-based integrated gasification combined-cycle (IGCC) plant in the Cook Inlet region of Alaska for the co-production of electric power and marketable by-products. The by-products, which may include synthesis gas, Fischer-Tropsch (F-T) liquids, fertilizers such as ammonia and urea, alcohols, hydrogen, nitrogen and carbon dioxide, would be manufactured for local use or for sale in domestic and foreign markets.

This report for Phase 1 summarizes the investigation of an IGCC system for a specific industrial setting on the Cook Inlet, the Agrium U.S. Inc. ("Agrium") fertilizer plant in Nikiski, Alaska. Faced with an increase in natural gas price and a decrease in supply, the Agrium is investigating alternatives to gas as feed stock for their plant. This study considered all aspects of the installation and infrastructure, including: coal supply and cost, coal transport costs, delivery routes, feedstock production for fertilizer manufacture, plant steam and power, carbon dioxide (CO_2) uses, markets for possible additional products, and environmental permit requirements.

Phase 2 of the project was initially planned to entail a generalized assessment of locating an IGCC plant at an alternative location in the Cook Inlet region, with plant size and design based on local and export markets for the suite of potential products. The Cook Inlet-specific Phase 1 results, reported here, provided insight and information that led to the conclusion that the second study should be for an F-T plant sited at the Usibelli Coal Mine near Healy, Alaska.

This Phase 1 case study is for a very specific IGCC system tailored to fit the chemical and energy needs of the fertilizer manufacturing plant. It demonstrates the flexibility of IGCC for a variety of fuel feedstocks depending on plant location and fuel availability, as well as the available variety of gas separation, gas cleanup, and power and steam generation technologies to fit specific site needs.

Background

Natural gas production from the major Cook Inlet fields is declining and known reserves are not sufficient to meet current demand beyond 2012. South Central Alaska natural gas prices have already risen and even in the best scenario, this upward trend will continue. The critical question is where South Central Alaska's future energy supplies will come from and at what price. Because of the declining natural gas supplies, the Agrium plant is scheduled to shut down in the fall of 2006.

The Cook Inlet/Susitna Basin coal fields contain 1.4 billion short tons of measured reserves (10.5 billion short tons of identified reserves). The measured reserves are equivalent to 21.4 trillion cubic feet of natural gas or 3.7 billion barrels of North Slope crude oil on a Btu content basis. This resource is the last undeveloped coal field in the United States that is on tidewater open to year-round shipping. It could be used for electric power production, export, converted to high value products, or a combination of these.

There is renewed interest in the Beluga coal field, part of the Cook Inlet/Susitna Basin, to meet industrial and power requirements in the region. The increasing population in the area will require additional electric power generation. New developments, such as the Pebble Project, a proposed gold-copper mine, will also require additional power. Beluga coal, however, will potentially compete with other energy sources. For example, a spur line to transport North Slope gas is currently being investigated. There is a need, therefore, to technically and economically evaluate the Beluga coal option on a similar timeline. Having a completed study available will provide a base case for making project selections.

Faced with the increasing cost and reduced availability of natural gas, Agrium, which owns and operates a fertilizer plant at Nikiski on the Cook Inlet, is investigating the use of coal feedstock as a replacement for natural gas. The Agrium "Blue Sky Project" will assess the value of coal gasification in this specific industrial setting. Their concept includes gasification and a separate power plant, but is not an IGCC design.

The sections below summarize the study's assumptions, project scope and results, key findings, conclusions/recommendations, and plans for Phase 2.

Project Scope and Results

In this investigation, two plant configurations were considered for comparison. Case 1 is a system designed entirely as an IGCC. The IGCC plant would satisfy the Agrium facility's entire feedstock and electric power needs. Because of the size of available components, the final design will have the capacity to produce excess electrical power that can be sold to the local grid.

The Case 2 design retains the gasification trains from Case 1 to produce the fertilizer feedstocks, but replaces the combined-cycle equipment with a conventional fluidized bed combustion system to produce steam for the plant and for power production.

The results of the investigation are summarized below under major topic areas.

Coal & Limestone – Beluga coal from an undeveloped mine approximately 30 miles across the Cook Inlet from Agrium's plant is likely the most economic source of coal for the Cook Inlet region. The proven reserves are more than sufficient to supply the plant for the life of the project. Developers are actively pursuing permitting for the Chuitna Mine and plan to begin exporting to Pacific Rim countries by 2010. A second option is to transport coal from the currently operating Usibelli Coal Mine near Healy, AK. Both mines would produce sub-bituminous coal with nearly identical properties. Usibelli coal must be shipped by rail to either Anchorage or Seward. The final leg of the delivery chain for Chuitna or Usibelli coal is a barge trip across the Cook Inlet. The provisions of the Jones Act require that all shipping between U.S. ports must be on U.S. made, owned, and manned vessels. The Chuitna coal could be delivered to the Agrium plant at $1.84 to $1.99/MMBtu ($31.00.98 to $33.51/tonne); Usibelli coal could be delivered at $1.96 to $2.11/MMBtu ($33.10 to $35.63/tonne).

Limestone will be required in the design Case 2. The Alaska Lime Company mine near Cantwell could supply limestone to Agrium for an estimated $115/tonne, in sufficient quantity to meet plant demands.

Value Added Products – The demand for the coal gasification by-products of the Beluga Coal Gasification Project have been investigated as part of this evaluation. The areas considered include international, domestic, regional and local markets. Typical gasification products and by-products assessed in Phase 1 include elemental sulfur, sulfuric acid, slag (as an aggregate or

replacement), carbon dioxide (CO_2), and Fischer-Tropsch diesel. The Phase 1 plant design does not include provisions for products other than fertilizer; however, the Phase 2 plant will be designed to produce Fischer-Tropsch fuels and other products. In Phase 2 the F-T analysis will be expanded. Phase 2 by-products may include nitrogen, carbon dioxide (for other than enhanced oil recovery), argon, and secondary value added by-products (naphtha, kerosene, etc.).

Carbon Dioxide – A coal gasification plant at the Agrium site would produce a significant quantity of CO_2. The carbon to hydrogen ratio for coal is much higher than for natural gas. Therefore, a coal gasification plant sized to meet the hydrogen requirements of fertilizer production produces more CO_2 than a plant fed with natural gas. The current natural gas fed plant emits about 114 MMscfd of CO_2 in both concentrated AGR (acid gas removal) and dilute flue gas streams. A gasification plant, of a size to produce an equivalent amount of hydrogen (the current study's Case 1 design) will emit about 280 MMscfd of CO_2. Of that 280 MMscfd, 91 MMscfd will be in a concentrated CO_2 gas stream from the acid gas processing section and 189 MMscfd will be in the form of dilute flue gas from the gas turbine stack. The desirability of developing a plant of this nature may hinge in part on the disposal or beneficial use of this CO_2. For that reason, this study assessed the potential of CO_2 for use in enhanced oil recovery (EOR) and for sequestration in underground reservoirs. There are more than a dozen reservoirs in the five major fields of Cook Inlet, within a 20-mile radius of the Agrium plant, that pass the screening criteria for miscible CO_2 floods.

- Using the average range of incremental increase in production (8 to 11%) via CO_2 flooding, the five major Cook Inlet oil fields have the potential to produce an incremental 290 to 400 million barrels of oil (MMbo). Using only the five major reservoirs and a 25% of cumulative production estimate, the incremental production would be approximately 300 MMbo.
- Screening level economics performed for the McArthur River field, the largest field in the Cook Inlet, suggest that an economic CO_2 flooding program in Cook Inlet's oil fields might be possible at oil prices greater than $35 to $40 per barrel, with the cost of CO_2 ranging from $0.50/Mcf to $1.20/Mcf. After the EOR assessment was completed, a preliminary economic analysis showed that the capital equipment cost for capturing and handling the CO2 was not economically feasible, thus the CO2 capture segment of the Case 1 and 2 designs was drooped and it was assumes that the gas would be vented. Refined analyses may show ways of using the CO2 for EOR that are feasible.
- The results of a successful flooding program could extend the life of the oil fields for 20 or more years and yield as much incremental oil as has been produced from these fields in the last quarter century.

Natural Gas Market – Agrium currently relies on scarce Cook Inlet natural gas as the chief feedstock for manufacturing fertilizer. Switching to synthesis gas from coal will increase the amount of natural gas available for other uses such as home heating and electric power generation in the Cook Inlet area. The impact on natural gas demand by eliminating Agrium as a natural gas customer was evaluated in another DOE/RDS study ("*Gas Needs and Market Assessment - Alaskan Spur Pipeline Project*" Contract No. DE-AM26-04NT41817, Task 211.01.06, completed in June, 2006). In that assessment, it was assumed that unless low cost natural gas is obtained the fertilizer plant will suspend operations in the fall of 2006. If the Agrium plant converts to coal as feedstock, effectively removing it from the regional gas market,

no effect on that assessment was found, because conversion to coal will have the same effect as a plant shut-down.

Electric Power Market – The impact of Agrium switching from natural gas to coal would have a small impact on the local power market. The most effective design of the gasification system includes electrical generation capacity sufficient to completely power the Agrium facility and provide 70 MW of power for sale to the grid. Under the current grid configuration and markets, the impact of this increment on local power generation and transmission needs would be minimal. The grid infrastructure could handle the power without significant upgrades and the market would be able to absorb it. Incremental revenue from the 70 MW of power capacity would be about $45.94/MWh in 2010.

Gasification Plant Design – The coal gasification plant investigated in this study is designed to provide Agrium's Kenai Nitrogen Operations (KNO) plant with the following suite of required products:

- 282 million standard cubic feet per day (MMSCFD) of hydrogen at 400 psig and of suitable quality for ammonia production.
- Stoichiometric quantity of nitrogen (approximately 100 MMSCFD) at 400 psig and 99.99% purity.
- 1,500,000 lb/hr steam at 1500 psig and a minimum temperature of 825°F.
- 300,000 lb/hr steam at 600 psig and 625°F.
- 5,000 TPD CO_2 suitable for urea production (25 psig)
- Electric power to satisfy the auxiliary power requirements for the gasification plant and the KNO facility, to make the entire facility electric power independent.

In addition to the products provided from the IGCC plant to the fertilizer plant, the fertilizer plant will return 1,200,000 lb/hr of high-pressure condensate at 1200 psig and 450°F to the IGCC facility.

Phase 1 assessed two alternative design configurations for meeting the KNO requirements:

Case 1: Process the syngas from the gasification plant to supply required hydrogen and nitrogen to the KNO ammonia synthesis loop compressor and produce sufficient steam and power for internal KNO consumption. This case employs a gas turbine for power production.

Case 2: Process the syngas from the gasification plant to supply required hydrogen and nitrogen to the KNO ammonia synthesis loop compressor, but do not produce power from a gas turbine. Rather, it would employ a fluidized bed coal combustion power plant to independently produce the required power and steam for the KNO facility.

Six gasification technologies were considered for this study, and the ConocoPhillips E-Gas technology was ultimately selected. The criteria considered included commercial status, ability to gasify the proposed feedstock, type of solid waste produced, oxygen/coal ratio, modular capacity of the gasifier, syngas composition, operating pressure and other byproduct potential.

Preliminary results from Case 1 indicated that the syngas availability from the gasification plant could be improved by replacing the 7FA gas turbine combined cycle with a CFB coal-fired boiler. Initial analysis also indicated that capital cost savings could be realized through this

change in plant configuration. However, to produce sufficient steam and power to satisfy KNO operations, the CFB boiler and associated steam turbine would have to be larger and less efficient, resulting in a higher capital cost per unit of output. Table ES.1 summarizes the performance characteristics and capital costs for Case 1 and Case 2.

Table ES.1 Case-by-Case Comparison of Performance and Capital Costs

	Case 1	Case 2
Power Production		
Gas Turbine	197 MW GE 7FA	N/A
Steam Turbine	36 MW	156 MW
Syngas Expander	N/A	16 MW
Net Plant Power	70 MW[1]	12 MW
Coal Feed		
To Gasifiers	11,700 TPD	10,680 TPD
To CFB Boiler	N/A	1,800 TPD
Overall Plant Efficiency, HHV[2]	54.8%	48.4%
Condenser Duty	270 MMBtu/hr	729 MMBtu/hr
Capital Cost Area ($1,000's)		
Gasification Island	$569,500	$567,900
Gas Cleanup	$261,600	$263,900
Gas Turbine and HRSG	$153,000	N/A
CFB Boiler	N/A	$254,700
Syngas Expander-Generator	N/A	$8,100
Steam Turbine-Generator	$12,600	$47,200
Cooling Water System	$9,400	$19,800
Feedwater System	$8,000	$26,100
Balance of Plant	$625,900	$682,300
Total Plant Cost	$1,640,000	$1,870,000

Financial Analysis

Financial analyses for both cases were performed using the Power Systems Financial Model Version 5.0 (developed by Nexant for DOE) and the case-specific design and project cost estimates. The Power Systems Financial Model has been used in numerous gasification studies, and is now the NETL standard for IGCC systems analysis. The key results desired from the analysis were the project return on equity investment, discounted cash flow, and identification of

[1] The Case 1 design will provide a Net Plant Power of 81 MW. However, due to the potential sale price for power at various levels, the economic analyses assumed 70 MW of power available for sale to the grid.

[2] In this case, Overall Plant Efficiency equals the power generated plus chemical value of the hydrogen generated divided by the thermal input to the plant. It does not take into account the efficiency of the down-stream process in which the hydrogen is used.

key model sensitivities. The amounts of hydrogen, nitrogen, CO_2, power, and steam exported to the Agrium facility were held constant. Table ES.2 shows the key model input differences and financial results for each case.

Table ES.2 Financial Cost Summary

	Case 1	Case 2
Plant EPC[3] Cost ($MM)[4]	1312	1498
Power Export to Grid (MW)	70	12
ROI (%)	11.1	6.0
Payback Year (2011 Start)	12 yrs.	20 yrs.

Case 1 clearly possesses superior financial potential relative to Case 2. While both cases produce enough raw materials necessary for ammonia and urea production at the Agrium facility, Case 2 is more expensive, produces less export power, and requires slightly more coal feed. Removal of the gas turbine from Case 1 and replacement in Case 2 with a CFB and a larger steam turbine to supply the necessary feedstocks to the Agrium plant does not appear to be economically justified.

Sensitivity analyses were performed on all model inputs in both cases. The items found to have the greatest impact on the financial results are the plant system availability, EPC cost, ammonia/urea prices, and delivered coal cost. None of the other model inputs impacted the ROI by more than 3 percentage points for the range of variables tested. Events that increase product prices and/or reduce capital or delivered coal costs will have a large positive influence on the project economics. The equity ROI remained positive after examining a wide range of potential conditions for EPC cost, availability, and coal price. For these inputs, the model results should be considered robust for this stage of the project analysis.

Because of the very wide range of potential values, the model input with the largest potential impact on project economics is the ammonia/urea price. In the last eight years, ammonia prices have ranged between $100 and $275/metric ton, with considerable volatility. Since this project has an estimated 30-year project life, the sensitivity analysis examined this entire price range. At ammonia prices at or below ~$150/metric ton, the project will have difficulty producing positive equity returns. None of the other financial model inputs impacted the results as strongly over the range of possible inputs considered. While this is not an issue that is unique to the development of a gasification facility at the Agrium site, it should have the greatest focus when making future capital investment decisions at the site.

The CO_2 produced from the proposed gasification plant has potential economic value for enhanced oil recovery operations in the region. An initial value of $0.50/MSCF of carbon dioxide was used after discussions with local oil and gas producers. Designing the plant to

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[3] Engineering, Procurement, and Construction

[4] This value is the same as the "Total Plant Cost" from Table ES.1 less the 25% contingency

capture and sell the CO_2 under those conditions yielded an IRR that was ~1 percentage point lower than the final Case 1 design. A sensitivity analysis on carbon dioxide showed that a value of nearly $1.00/MSCF would be necessary to make the increased capital expenditure a break-even proposition with Case 1. Since it was estimated that this value is higher than what could be obtained in the Alaskan market, equipment for carbon dioxide capture and storage was removed from the base case designs.

Environmental Issues – Construction and operation of an IGCC facility at the existing Agrium Kenai Plant would require a number of federal, state and borough environmental permits. Environmental issues pertaining to air emissions, water supply, wastewater discharges, management of solid and hazardous wastes, and marine ecological impacts would need to be addressed in the project planning and design process to ensure compliance with existing regulatory requirements. In addition, one or more of the federal agencies with permitting jurisdiction could require an Environmental Assessment or an Environmental Impact Statement in accordance with the National Environmental Policy Act (42 U.S.C. § 4321 et seq.).

Phase 1 Conclusions:

The analyses showed that:

- The conversion of the Agrium plant is technically and economically feasible under the assumptions made. In the most financially attractive feasible case, Case 1 had an internal rate of return of 11.1%; Case 2 had an IRR of only 6.0%. Developers and investors use economic hurdles to judge investments and risk. Each case is different, so whether this yield is sufficiently high to secure financial commitments is a decision that can only be made by developers.
- There are sufficient coal resources to supply the plant at an economic delivered price.
- CO_2 will be produced in sufficient quantity and at a cost that may permit enhanced oil recovery in the Cook Inlet. The potential exists to recover as much as 300 MMbo – equaling the last 25 years of production. However, the CO_2 sales price will have to be greater than currently projected for this to be economically feasible.
- Large domestic and export markets exist for many by-products.
    - The developing Fischer-Tropsch diesel market has potentially the best return, but is also the one that is the least understood at this time.
    - Elemental sulfur and sulfuric acid have good and well understood world-wide markets.
    - Slag will need to be marketed locally as low-density aggregate, road building material, or sand blasting grit.
- Natural Gas - No change to the predictions described in *"Gas Needs and Market Assessment - Alaskan Spur Pipeline Project"*[5] was found.

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[5] Thomas, C.P. and C. Ellsworth, et al, (RDS), "Gas *Needs and Market Assessment - Alaskan Spur Pipeline Project*" Contract No. DE-AM26-04NT41817, Task 211.01.06, completed in June, 2006.

- Electric power - The 70 MW of export power will bring a sales price of about $45.95/MWh in 2010. This excess power will not result in major impacts on the generation or transmission systems in the region over the time period evaluated.
- An analysis of the current design basis indicates that a proposed IGCC facility at the Agrium Kenai Plant is feasible in terms of current environmental permitting and compliance requirements imposed by federal, state and local regulations. Detailed environmental compliance strategies and mitigation measures would need to be developed in concert with design details and operational plans.

Phase 2 Project Plan:

The Phase 1 plant was designed for a very specific size, optimized for the level of production at the Agrium plant. In Phase 2, a plant based on the Phase 1 design will be considered for location at the Usibelli Coal Mine, near Healy. An NETL project[6] has determined that Healy would be the third most likely coal-to-liquids plant site in Alaska, after Nikiski and Beluga. Alaska Natural Resources to Liquids Company is pursuing a private sector initiative to develop the Alaska Beluga Coal-to-Liquids Project (AK Beluga CTL) on the west side of Cook Inlet. Since the Nikiski site was used in Phase 1 and AK Beluga CTL is underway, the Healy site was selected for Phase 2. The Healy plant will be optimized for commodity production levels consistent with expected local and export market demand and for electric power output levels consistent with growth projections and infrastructure capabilities. The conceptual design of this plant will be based on the design of the Phase 1.

Alaska Natural Resources to Liquids Company is pursuing a private sector initiative to develop the Alaska Beluga Coal-to-Liquids Project (AK Beluga CTL) on the west side of Cook Inlet. The AK Beluga CTL plant is also a gasification based facility and is on much scale larger (80,000 barrels per day) than that considered in Phase 1 of this study. As part of Phase 2, an investigation of the feasibility of piping synthesis gas from the proposed CTL plant to the Agrium plant will be undertaken.

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[6] Integrated Concepts and Research Corporation (ICRC), "Production and Demonstration of Synthesis Gas-Derived Fuels" NETL Contract DE-FC26-01NT41099

Contributors and Acknowledgements

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The analytical portion of this study was conducted over a five month period beginning in October 2005. Assistance and support was received from many agencies and industry. Specifically, the authors thank members of the Advisory Committee for input and guidance, and for providing assistance in obtaining publicly available data in a timely and efficient manner.

Advisory Committee

An Advisory Committee was formed to review the scope of work, monitor progress, and make suggestions for further work. The primary function of the committee was to make sure the most critical issues were addressed and to assist in obtaining critical data. The Advisory Committee met on December 1, 2005 and February 17, 2006. The committee members are listed below.

- **Agrium U.S. Inc**: Lisa Parker, Corporate Relations; Tim Johnson, Technical Services
- **Alaska Department of Natural Resources**: Rick Fredericksen, Mining Section Chief, Division of Mining, Land, and Water
- **Alaska Governors Office**: Linda Hay, Special Staff Asst. - Resources
- **Alaska Industrial Development and Export Authority**: Ron Miller, Executive Director
- **Alaska Power Association**: Brad Janorschke, General Manager Homer Electric Association
- **DRven**: Robert Stiles, President, Mine Owner Representative
- **Usibelli Coal Mine**: Steve Denton, V.P. Business Development
- **At-Large:** Eric Yould
- In addition to their participation in the Advisory Committee, several members were interviewed by phone and in person, in some cases multiple times, regarding select opportunities. They graciously shared materials and estimates, and directed us to visit web sites and interview other agencies and developers involved in the industrial opportunities.

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February 1, 2010

Memorandum
TO: Senator Lesil McGuire
FROM: Chuck Burnham, Legislative Analyst
RE: Advanced Coal Technology: Wyoming Coal to Liquids Facility and State Incentives
LRS Report 10.108

You asked for an overview of the state regulatory and taxation regimes applicable to the Medicine Bow coal to liquids (CTL) facility currently under development in southeastern Wyoming.[1] You were also interested in state incentives to encourage development of CTL or other advanced coal technologies.

Briefly, our research located no Wyoming regulatory or taxation measures that are specific to CTL or to the Medicine Bow facility under development.

Taxation

We asked Craig Grenvik, administrator of Wyoming's Mineral Taxes Division, if any taxation framework was being developed specific to CTL. Mr. Grenvik stated that no such framework had been detailed and that, whatever the design of the final regime, his experience suggests that new tax regulations will be litigated.[2]

If the Medicine Bow facility were to be subject to the Wyoming state fiscal regime for coal production that is in place today, the following would apply:

- **Severance Tax:** 7 percent for surface mines (3.5 percent for underground mines);
- **Ad Valorem – Production**: Levied by counties on value of production at the mine mouth. Average Rate: 60 mills (6 percent).
- **Ad Valorem – Property**: Levied by counties on assessed valuation of physical property, such as mining facilities and equipment. Average Rate: 60 mills (6 percent).
- **Sales and Use Taxes**: Levied by the state and local government on purchases of goods and services. Rate: 4 to 6 percent depending on county.
- **State Royalties and Rents**: 12.5% (surface) and rents, $1 to $4 per acre.[3]

[1] As you know, the proposed $2.7 billion Medicine Bow facility is projected to begin producing 20,000-22,000 barrels of transportation fuels per day in 2014 using low-sulfur coal from a collocated mine. More information on the project is available on the website of its parent company, DKRW Advanced Fuels, at *http://www.dkrwenergy.com/fw/main/Medicine-Bow-111.html*.

[2] Mr. Grenvik can be reached at (307) 777-5237, or by email at *cgrenv@state.wy.us*.

[3] In addition to state taxes, royalties, and rents, facilities located on federal land are subject to federal royalties of 12.5 percent (which are ultimately shared with the state), and fees for the Abandoned Mine Lands fund. Wyoming fiscal information is from "A Concise Guide to Wyoming Coal," Wyoming Mine Association; available through *http://www.wma-minelife.com/*.

Regulation

Regulatory processes for the Medicine Bow project will presumably be largely the same as those for traditional coal mines and petroleum refiners, although additional regulations may be developed relating to the planned liquefaction and transportation of carbon dioxide (CO_2), which will be sold to oil producers for reinjection in order to pressurize wells and increase production. At this point in the facility's development, the primary applicable regulations are those related to industrial siting and environmental permitting, which apply to all industrial facilities and potential large-scale emitters of pollution. We provide links to regulatory reports and permitting documents below:

- "Medicine Bow Fuel & Power, LLC, Coal-to-Liquids Project Industrial Siting Permit Application," prepared by CH2M Hill, September 2007, *http://deq.state.wy.us/out/downloads/MBFP_ISA_Permit_Application_09-17-07_Final.pdf*. This document provides project, construction, and operation descriptions and analysis of socioeconomic impacts of the facility. Appendices to the report are available at *http://deq.state.wy.us/isd/isdnews.htm* [see the bottom of the page].

- "Final Opinion of Water Supply and Water Yield Analysis for Medicine Bow Fuel and Power's Proposed Coal-to-Liquid Plant and Saddleback Hills Coal Mine in Carbon Basin, Carbon County, WY," Wyoming State Engineer's Office, Ground Water Division, October 2007, *http://deq.state.wy.us/isd/downloads/MBFP%20SEO%20Final%20Opinion.pdf*.

- Archive of documents related to the challenge of the approval of Medicine Bow's air quality permit, available on the website of the Wyoming Environmental Quality Council (*http://deq.state.wy.us/eqc/m*) through the link to "In the Matter of Medicine Bow Fuel and Power, LLC Air Permit CT-5873, EQC Docket No. 09-2801" The permit itself is available through the link "Exhibit F." That document lists the specific emissions standards applicable to the facility.

- Although not solely related to the Medicine Bow facility, the Wyoming Legislature formed a Carbon Sequestration Working Group, which published its report in September 2009. To the extent the findings and recommendations of the group are adopted and implemented, the report may impact the development of the project. The report is available at *http://deq.state.wy.us/carbonsequestration.htm*.

State Incentives

Attached are two documents that provide details on state incentives for advanced coal technologies. They are as follows:

- "State Incentives for Advanced Coal Projects," Coal Utilization Research Council, 2006; and
- Julia Verdi, "Incentives for Coal Gasification Plants," National Conference of State Legislatures, January 12, 2010.

I hope this information is useful. Please do not hesitate to contact us if you have questions or require further information.

State Incentives for Advanced Coal Projects

Several states have adopted incentives for advanced coal projects. This report examines the state incentives currently available for advanced coal projects as well as proposals for incentives and provides resources for obtaining additional information.

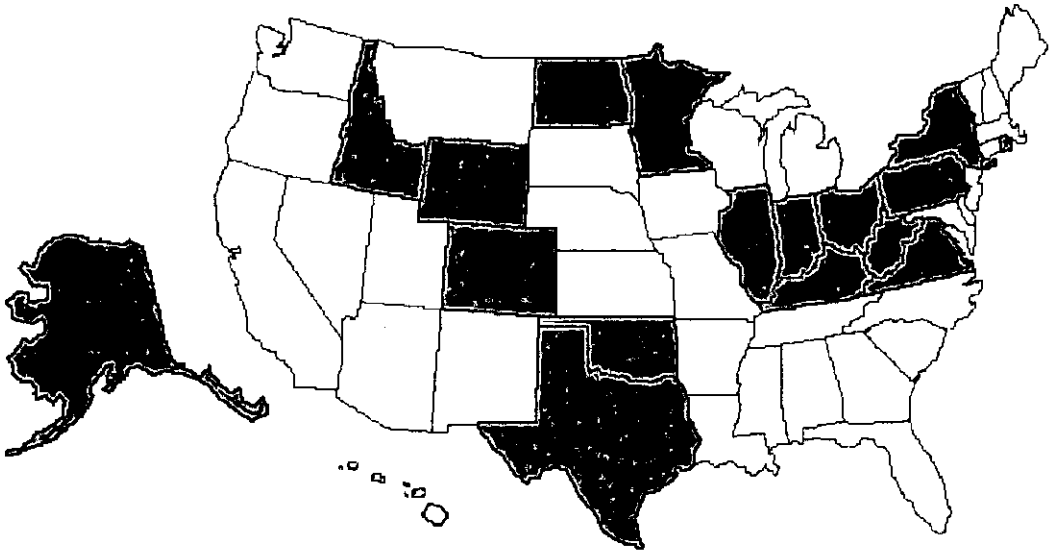

Fig. 1 – States with current incentives for advanced coal projects (Alaska, Colorado, Idaho, Illinois, Indiana, Kentucky, Minnesota, New York, North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, Texas, Virginia, West Virginia, and Wyoming) are shaded.

Prepared by the Coal Utilization Research Council, 2006

ALASKA

The state of Alaska has provided assistance to a clean coal project through its Alaska Industrial Development and Export Authority (AIDEA). The AIDEA Development Finance Program can provide bond financing to a "plant or facility demonstrating technological advances of new methods and procedures and prototype, commercial applications for the exploration, development, production, transportation, conversion, and use of energy resources."[1] This program provided $85 million in bond funding for the 50 MW Healy Clean Coal Project in the 1990's. Projects must be able to demonstrate that they will be able to produce adequate revenues to repay the bonds. Projects seeking financing over $10 million must be approved by the state legislature.

COLORADO

In 2006, Colorado adopted legislation to encourage the construction of a clean coal technology demonstration project.[2] The legislation provides incentives for an IGCC project, which is defined as a facility in Colorado that uses Colorado or other western coal to generate electricity and demonstrates the capture and sequestration of a portion of the project's carbon dioxide emissions. Additionally, the plant may not exceed 350 MW nameplate capacity without a finding from the Colorado Public Utilities Commission (CPUC) that the larger size is necessary to obtain the benefits of federal cost-sharing, financial grants or tax benefits, or other financial opportunities.

The legislation provides a variety of incentives for IGCC projects, including:

- Waivers of the CPUC's certificate of public convenience and necessity requirement
- Full cost recovery from customers, including full life-cycle capital and operating costs associated with the IGCC project
- Recovery of additional costs for electricity purchased due to planned and unplanned outages of an IGCC project.
- Waiver of CPUC rules requiring competitive resource acquisition
- With CPUC approval utilities may enter into a power purchase agreement with the owner of the IGCC facility that provides compensation to the facility owner for its costs and provides a reasonable return on investment. Such payments by a utility are recoverable through a rate adjustment clause on a timely basis.

Finally, IGCC projects are eligible for financial assistance from the Governor's Office of Energy Management and Conservation through the Clean Energy Development Fund. Currently, $2 million per year is appropriated for the fund through fiscal year 2008.[3]

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[1] ALASKA STAT. § 44.88.900(9)(D).
[2] 2006 COLO. SESS. LAWS 1413 (HB06-1281, signed into law on June 1, 2006). Available at http://www.state.co.us/gov_dir/leg_dir/olls/sl2006a/sl_300.pdf.
[3] 2006 COLO. SESS. LAWS 1738 (HB06-1322, signed into law on June 6, 2006). Available at http://www.state.co.us/gov_dir/leg_dir/olls/sl2006a/sl_347.pdf.

IDAHO

Idaho has adopted a moratorium on the construction of new coal fired power plants effective until April 2008.[4] The moratorium, however, does not apply to IGCC facilities.

ILLINOIS

Coal Revival Program[5]

Direct financial assistance is available for capital costs including buildings, structures, durable equipment and land at new facilities.[6] To qualify, a facility must:

(1) create 400 MW of new generating capacity, use coal or gases derived from coal as its primary fuel source, and support the creation of at least 150 new Illinois coal-mining jobs, OR

(2) Use coal gasification or IGCC to generate chemical feedstocks, transportation fuels or electricity.

The amount of the grant will depend on the state occupation and use taxes to be paid on Illinois-mined coal used at the new facility.[7] The maximum grant to any one facility is $100 million.

High Impact Business Program[8]

New or expanded electric generating facilities using coal are now eligible to apply for High Impact Business designation. This program offers a sales tax exemption on building materials and equipment, a utility tax exemption, and an investment tax credit.

Property Tax Abatement[9]

Facilities may be eligible to receive property tax abatement from local taxing districts. Facilities receiving a new High Impact Business designation are eligible for up to $4 million in property tax abatements over a 10 year period. Other facilities meeting

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[4] IDAHO CODE ANN. § 39-125.

[5] To view grant application information view this document fromthe Illinois Department of Commerce and Economic Opportunity (DCEO) website.

[6] To be considered a "new facility" construction must have commenced on or after July 1, 2001. 20 ILL. COMP. STAT. 605/605-332(a).

[7] Funding is roughly equal to the present value of future sales taxes paid on Illinois-mined coal over a 25-year period. 20 ILL. COMP. STAT. 605/605-332(b)(3).

[8] For more details on the High Impact Business program view pages 2-3 of this document from the Illinois DCEO website. *See also* 20 ILL. COMP. STAT. 655/5.5.

[9] For more details on property tax abatement view page 3 of this document from the Illinois DCEO website. *See also* 35 ILL. COMP. STAT. 200/18-165.

the definition of "new electric generating facility"[10] are eligible for property tax abatement on a sliding scale based on the valuation of the facility.[11]

A brochure produced by the Illinois Department of Commerce and Economic Opportunity (DCEO) Office of Coal Development regarding direct financial assistance via the Revival program, the High Impact Business program, and tax abatement program is available from the DCEO website.

Long-Term Contracting[12]

In 2005, Illinois amended the Public Utilities Act to allow any gas utility to enter into a 20-year supply contract with any company for synthetic natural gas produced from coal through the gasification process. To qualify, the coal gasification facility must commence construction by July 1, 2008. Further, the amended Act provides that costs paid for synthetic natural gas are reasonable and prudent and recoverable for the first 10 years of the contract if certain conditions are met (most notably that the contract was entered into by June 21, 2006).

Illinois DCEO Coal Grant Programs

- Coal Competitiveness Program
  - Purpose: For projects that improve coal extraction, preparation and transportation systems in Illinois
  - Amount: $50,000 to $1.5 million, up to 20 percent of project cost

- Coal Research Program
  - Purpose: To fund universities and other research institutions focusing on clean coal technology development, coal chemistry, mining productivity and coal combustion byproduct utilization
  - Amount: $60,000 to $250,000

- Coal Development Program
  - Purpose: To advance promising clean coal technologies beyond the research stage towards commercialization by providing a 50/50 match with private industry dollars, typically to universities and technology developers
  - Amount: $250,000 to $600,000

[10] To qualify as a "new electric generating facility" the facility must create 400 MW of new generating capacity, use coal or gases derived from coal as its primary fuel source, and support the creation of at least 150 new Illinois coal-mining jobs. 20 ILL. COMP. STAT. 605/605-332(a).
[11] 35 ILL. COMP. STAT. 200/18-165.
[12] 220 ILL. COMP. STAT. 5/9-220(h).

- Coal Demonstration Program
  - Purpose: To provide partial funding for selected large-scale demonstration of advanced coal systems for utility and industrial use that will produce significant economic benefits for Illinois
  - Amount: $1 million to $30 million (A project-specific appropriation and approval by the governor are required

For more information on Illinois' grant programs, including applications, visit the DCEO's website at http://www.illinoisbiz.biz/dceo/Bureaus/Coal/Grants.

INDIANA

Tax Credits for IGCC Facilities[13]

Indiana has tax credits available to newly constructed[14] IGCC power plants located in Indiana. The facility must convert coal into synthesis gas and use that gas to generate electric energy. To qualify facilities must also be dedicated primarily to serving Indiana retail electric utility consumers.

The tax credit is equal to the sum of 10 percent of the first $500 million of investment in the facility plus 5 percent of any investment over $500 million. The credit is spread out over 10 years. In each year the credit is multiplied by the percentage of Indiana coal used at the facility.[15]

Financial Incentives for Clean Coal and Energy Projects[16]

Several types of projects qualify for financial incentives under this program, including:

- New energy generating facilities that use clean coal technology and are fueled primarily by Illinois Basin coal or coal gases
- Projects that reduce regulated air emissions from existing energy generating plants that are fueled primarily by Illinois Basin coal or coal gases
- Projects to provide transmission service to a new energy facility
- Projects to develop alternative energy sources, including renewable energy
- The purchase of fuels produced by a coal gasification facility
- Projects meeting any of the above criteria that use coal bed methane[17]

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[13] IND. CODE § 6-3.1-29

[14] The Indiana Code defines "new energy generating facility" at IND. CODE § 8-1-8.8-8. Notably, the repowering, construction or expansion must have begun after July 1, 2002.

[15] Indiana coal is defined as coal from a mine whose coal deposits are located in the ground wholly or partially in Indiana regardless of the location of the mine's tipple. IND. CODE § 4-4-30-4.

[16] IND. CODE § 8-1-8.8.

[17] The incentives legis lation was initially enacted in 2002. In 2005 the statute was amended to include projects that use coal bed methane in the definition of "clean coal and energy projects." However, the section of the statute regarding incentives was not amended and does not explicitly provide for financial incentives for coal bed methane projects. It is possible that the Indiana Utility Regulatory Commission could view this as a clerical oversight rather than a legislative policy choice and exercise its discretion

Incentives for these projects include timely recovery of costs and an additional three percentage points on the return on shareholder equity that would otherwise be allowed. The timely recovery of costs incentive allows for rate adjustment via a "tracker" instead of a full blown rate case to recover costs for incurred in the construction, repowering, expansion, operation or maintenance of a qualifying facility. The financial incentives program is administered by the Indiana Utility Regulatory Commission.

KENTUCKY

Kentucky currently provides tax credits for clean coal facilities.[18] The amount of the credit is $2 per ton of Kentucky coal purchased used at a certified clean coal facility. To qualify a facility must:

- Have begun operations after January 1, 2005
- Have a cost greater than $150 million
- Be located in Kentucky
- Be certified by the Kentucky Environmental and Public Protection Cabinet as reducing emissions of pollutants released during generation of electricity through the use of clean coal equipment and technologies
- Not have claimed the incentive ton tax credit with the same coal[19]

After the enactment this tax credit in 2005, the Kentucky Public Service Commission (KPSC) issued a report that called for adoption of incentives for IGCC, possibly including grants, low interest loans, and tax credits.[20] The KPSC stated that it was uncertain whether an IGCC facility would qualify for a certificate of public convenience and necessity under current Kentucky law and that it was unclear how the environmental benefits of an IGCC facility could be accounted for in an environmental surcharge proceeding. The KPSC recommended extending the incentives currently offered for renewables to IGCC and called for discussion of financing IGCC facilities via securitization.

In June 2006, Kentucky adopted legislation that provides incentives for a potential FutureGen site.[21] A FutureGen site approved by DOE would be exempt from Kentucky taxes on the sale, rental, storage, use or other consumption of tangible personal property used to construct , repair, renovate, or upgrade the facility, including repair and replacement parts purchased for the plants.

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under IND. CODE § 8-1-8.8-11(a)(5) to award "other financial incentives the commission considers appropriate" to coal bed methane projects.

[18] KY. REV. STAT. ANN. § 141.428.

[19] KY. REV. STAT. ANN. § 141.0405. This section provides a $2 per ton tax credit for coal-fired electric generation for tons of coal purchased above the baseline year (1999) level.

[20] Kentucky's Electric Infrastructure: Present and Future, Report of the Kentucky Public Service Commission, August 22, 2005. Available at http://psc.ky.gov/agencies/psc/hot_list/ElectricRpt_082205/MainRpt/electric1_CompleteRpt.pdf.

[21] HB 1, 2006 Extraordinary Session of the Kentucky Legislature, signed into law on June 28, 2006. Available at http://www.lrc.ky.gov/record/06SS/HB1/bill.doc.

MINNESOTA

Unlike other states that have adopted generally applicable legislation to encourage the adoption and development of clean coal technology, Minnesota has taken a more specific approach. The Minnesota statute provides incentives to the Mesaba Energy IGCC plant.[22] The legislation provides for an annual grant of $2 million for five years, exempts the Mesaba plant from the requirement of a certificate of need, and entitles the developer to enter into a 450 MW long-term power purchase agreement with Xcel Energy.

NEW YORK

New York's Governor George Pataki has launched the Advanced Clean Coal Power Plant Initiative (ACCPPI) with the goal of building one or more advanced coal power plants in the state. The ACCPPI Shovel Ready Team[23] is conducting feasibility studies and initial environmental reviews of potential sites. The Team is scheduled to issue its final report and requests for proposals on September 1, 2006. Applications are due by October 31, 2006 and the winning proposals are expected to be announced in December 2006.

ACCPPI is offering a variety of financial incentives to winning proposals, including:

- New York Power Authority (NYPA) will agree to enter into a power purchase agreement with the developer
- If requested, NYPA may become a minority share partner in the project
- NYPA will establish a Clean Coal Initiative Fund ($50 million) to implement carbon sequestration technology when it becomes available
- Tax exempt bonding authority of up to $200 million per year, capped at $1 billion
- Qualification for Empire Zone tax treatment regardless of location
- Brownfield Cleanup Program benefits in qualifying locations

NORTH DAKOTA

The North Dakota Constitution provides that up to 20 percent of funds in the coal development impact trust fund may be appropriated for clean coal demonstration projects.[24] Projects must be submitted to the North Dakota Industrial Commission for approval.

Additionally, all new coal plants in North Dakota are eligible for a tax deduction equal to one percent of total wages and salaries paid in the state for the first three years

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[22] MINN. STAT. § 216B.1694.

[23] The Shovel Ready Team is made up of the Governor's Office of Regulatory Reform, New York Power Authority, New York State Energy Research and Development Authority, Department of Environmental Conservation, Empire State Development, and the Public Service Commission.

[24] N.D. CONST. art X, section 21.

and one-half of one percent for the fourth and fifth years.[25] Investments in new power plant construction, repowering, or environmental upgrades may also be eligible for an exemption from the state's 5 percent sales and use tax.[26] North Dakota also provides for an exemption from 85 percent of the state's installed capacity tax (with the possibility of the local government waiving its 15 percent) and a full exemption from the state's production tax.[27]

OHIO

Ohio administers its clean coal incentives through the Ohio Coal Development Office (OCDO).[28] The OCDO makes awards funds to coal research and development projects with a goal of assisting in the deployment of cost-effective technologies that can enable the use of high-sulfur Ohio coal in compliance with current and future environmental limits. The OCDO offers grants, loans, and loan guarantees.

The OCDO periodically seeks projects through public solicitations and requests-for-proposals (RFPs), most recently in the spring of 2005. Once an RFP is submitted, it is reviewed by independent technical reviewers and submitted to the Technical Advisory Committee (TAC). Projects favorably recommended by the TAC are subject to final approval by the Ohio Air Quality Development Authority (OAQDA). The specific amount of funds available for individual projects is set by each RFP.[29]

In 2006, Ohio expanded its definition of "air quality facility" to include (1) any coal research and development project[30], (2) property used in connection with the by-products of a coal research and development project[31], and (3) property that is a part of the FutureGen project.[32] Being designated an "air quality facility" allows a project to seek state-funded mortgage insurance from the Development Financing Advisory Council[33] and financing from OAQDA issued revenue bonds.[34]

Ohio also created the FutureGen Initiative Fund and appropriated $1.25 million towards the drilling of test wells to assist the state's efforts to secure the FutureGen project.[35]

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[25] N.D. CENT. CODE § 57-38-30.1.
[26] N.D. CENT. CODE § 57-40.2-04.2.
[27] N.D. CENT. CODE § 57-60-02.
[28] OHIO REV. CODE ANN. § 1551.32.
[29] In the most recent RFP, funds for an individual project were capped at the lesser of $5 million or one-third of the total project cost for full-scale projects and lower amounts for smaller projects.
[30] As used in the definition of "air quality facility" a "coal research and development project" is defined by § 1555.01(C) of the Ohio Code as a project that is financed, in whole or in part, with a grant or loan from the OCDO.
[31] *Id.*
[32] OHIO REV. CODE ANN. § 3706.01.
[33] OHIO REV. CODE ANN. § 122.451.
[34] OHIO REV. CODE ANN. § 3706.03.
[35] OHIO REV. CODE ANN. § 3706.101; HB 440, 126th Ohio Legislature, signed into law on April 4, 2006.

OKLAHOMA

Oklahoma offers coal-fired electric generation facilities a tax credit of $5 per ton of Oklahoma-mined coal.[36]

PENNSYLVANIA

Pennsylvania's Alternative Energy Portfolio Standards Act[37] requires electric distribution companies and electric generation suppliers to provide a percentage of their electricity from alternative energy sources. Following the enactment of the Act in 2004, companies must provide the following percentages of their electricity from Tier II alternative energy sources, including IGCC[38]:

Years 1-4	4.2 percent
Years 5-9	6.2 percent
Years 10-14	8.2 percent
Years 15+	10 percent

Pennsylvania's Governor has also proposed the Energy Deployment for a Growing Economy (EDGE) initiative, which would offer incentives for IGCC technology. These incentives would include[39]:

- Priority funding from the Pennsylvania Economic Development Financing Authority (PEDFA) and the Pennsylvania Energy Development Authority (PEDA) through low-interest loans
- Allowing long term contracts for gas and electricity products
- Permitting synthetic gas producers to operate without the burden of utility regulation when they serve and sell to limited purchasers such as chemical, manufacturing or industrial facilities
- Ensuring that electricity produced by these plants will be subject to the pricing and cost-recovery provisions of the state's Alternative Energy Portfolio Standards Act

The State of Pennsylvania is also in negotiations with EPA to allow utilities a one-time option of allowing older facilities to continue using coal without updated air pollution controls if the utility agrees to replace the plant with an IGCC facility by 2013.[40]

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[36] OKLA. STAT. tit. 68, § 2357.11.
[37] 73 PA. CONS. STAT. § 1647.2.
[38] Waste coal is also a Tier II alternative energy source. Coal mine methane is considered a Tier I alternative energy source. Under the Act, the Tier I sources must account for eight percent of electric energy sold in 2020.
[39] Press Release, Pennsylvania Department of Environmental Protection, Federal Appeals Court Sides with Pa., 13 Other States in Suit Against EPA (March 20, 2006) (available online at http://www.depweb.state.pa.us/news/cwp/view.asp?Q=495309&A=3).
[40] *Id.*

RHODE ISLAND

Rhode Island law directs the state's energy facilities siting board to give priority to projects based on eight criteria, one of which is the use of coal processed by clean coal technology.[41] Rhode Island defines clean coal technology as a technology developed in the DOE clean coal technology program and shown to produce emissions levels substantially equal to those of natural gas fired power plants.[42]

TEXAS

In 2005, the Texas legislature provided $22 million in grant funds for clean-coal and gasification projects.[43] Texas also funded the site screening process for possible FutureGen plants and allows expedited permitting for projects that are related to the construction of a FutureGen component.[44]

In 2006, Texas adopted legislation that instructs the Railroad Commission of Texas to acquire ownership of carbon dioxide captured by a FutureGen project located in the state.[45] This would relieve the entity operating a FutureGen project of potential liability for the carbon dioxide captured and sequestered.

VIRGINIA

Virginia allows "clean coal projects"[46] priority in the processing of permit applications with the State Air Pollution Control Board.[47]

WEST VIRGINIA

The West Virginia public service commission has the authority to authorize rate-making allowances for electric utility investment in clean coal technologies.[48]

WYOMING

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[41] R.I. GEN LAWS § 42-98-2.
[42] R.I. GEN LAWS § 42-98-3.
[43] TEX. GOV'T CODE ANN. § 2305.037; Press release, Railroad Commission of Texas, Texas Recognized for Leadership in Clean Coal Technology Efforts (Dec. 2, 2005) (available online at http://www.rrc.state.tx.us/news-releases/2005/120205.html).
[44] TEX. HEALTH & SAFETY CODE ANN. § 382.0565 & TEX. WATER CODE ANN. § 5.001(6).
[45] HB 149, signed May 31, 2006 79th Texas Legislature, 3rd called session. Available at http://www.capitol.state.tx.us/cgi-bin/tlo/textframe.cmd?LEG=79&SESS=3&CHAMBER=H&BILLTYPE=B&BILLSUFFIX=00149&VERSION=5&TYPE=B.
[46] Virginia defines "clean coal project" as "any project that uses any technology, including technologies applied at the precombustion, combustion, or postcombustion stage, at a new or existing facility that will achieve significant reductions in air emissions of sulfur dioxide or oxides of nitrogen associated with the utilization of coal in the generation of electricity, process steam, or industrial products, which is not in widespread use, or is otherwise defined as clean coal technology pursuant to 42 U.S.C. § 7651n." VA. CODE ANN. § 67-400.
[47] VA. CODE ANN. § 67-401.
[48] W. VA. CODE § 24-2-1g.

In 2006, Wyoming passed legislation creating a sales and use tax exemption for new coal gasification or coal liquefaction facilities and the equipment used to construct a new facility or make it operational.[49] The exemption does not apply to tools and other equipment used in construction of a new facility, contracted services required for construction and routine maintenance, or equipment utilized or acquired after the facility is operational.

STATES CONSIDERING ADVANCED COAL INCENTIVES

The following states have taken undertaken studies of potential incentives for advanced coal technologies and/or expressed a strong interest in developing such technologies in their state.

Arizona

- In 2006 Arizona created the Clean Coal Technology Task Force comprised of government and industry participants.[50] The task force is charged to "determine whether new state policies or incentives are needed to promote the development of new clean coal fired power plants in this state."

Montana

- Montana's Governor has expressed a strong interest in using coal to produce synthetic fuels, but no incentives have been enacted. One proposed bill for the Montana legislature's upcoming 2007 session would offer tax breaks on equipment used for carbon sequestration.[51]

Wisconsin

- In 2005, Wisconsin Governor Jim Doyle asked the state Public Service Commission and the Department of Natural Resources to investigate the potential of IGCC technology in Wisconsin. A June 2006 Draft Report from the study group outlined 22 potential steps for the state to consider that would advance IGCC technology in Wisconsin.

WESTERN GOVERNORS' ASSOCIATION PROPOSAL

The Western Governor's Association's Advanced Coal Task Force recently recommended that the Western Governors and the Western states provide direct financial assistance, recovery of costs, expedited permitting and other incentives for the development of advanced coal technologies.[52]

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[49] 2006 Wyo. Sess. Laws, Chapter No. 14 (H.B. 61, signed into law on March 9, 2006).
Full text of the legislation is available at http://legisweb.state.wy.us/2006/Enroll/HB0061.pdf.

[50] H.B. 2475, Forty-seventh Arizona Legislature, Second Regular Session, signed into law on May 9, 2006. Available at http://www.azleg.gov/legtext/47leg/2r/bills/hb2475h.pdf.

[51] The bill is in the drafting process. Updates are available at http://laws.leg.state.mt.us/pls/laws07/LAW0210w$BSIV.ActionQuery?P_BILL_DFT_NO5=LC0089&Z_ACTION=Find.

[52] The complete recommendations are available online at http://www.westgov.org/wga/meetings/am2006/CDEAC06.pdf (see Appendix A).

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Incentives for Coal Gasification Plants
January 12, 2010
Julia Verdi

Alabama

CODE OF ALABAMA TITLE 40. REVENUE AND TAXATION. CHAPTER 9B. TAX INCENTIVE REFORM ACT OF 1992. s 40-9B-4. Authorization of abatement.

(f)(1) For a qualifying industrial or research enterprise described in Section 40-9B-3(a)(10)e., which is owned by a utility described in Section 37-4-1(7)a., and which is a coal gasification or liquefaction project or an advanced fossil-based generation project, as such terms are defined in Section 40-18-1, or which utilizes hydropower production, an abatement under this section shall be in an amount equal to 100 percent of the state noneducational ad valorem taxes owed for plant, property, and facilities for the maximum exemption period, and in an amount equal to 50 percent of the state construction related transaction taxes. The abatement shall not be subject to the procedures in Section 40-9B-5 or 40-9B-6.

Indiana

TITLE 4. STATE OFFICES AND ADMINISTRATION ARTICLE 4. LIEUTENANT GOVERNOR; DEPARTMENT OF COMMERCE CHAPTER 11.6. ADDITIONAL AUTHORITY; SUBSTITUTE NATURAL GAS CONTRACTS 4-4-11.6-12 Legislative findings

Sec. 12. The general assembly makes the following findings:

(1) The furnishing of reliable supplies of reasonably priced natural gas for sales to retail customers is essential for the well being of the people of Indiana. Natural gas prices are volatile, and energy utilities have been unable to mitigate completely the effects of the volatility.

(2) Long term contracts for the purchase of SNG between the authority and SNG producers will enhance the receipt of federal incentives for the development, construction, and financing of new coal gasification facilities in Indiana.

(3) The authority's participation in and oversight of the purchase, sale, and delivery of SNG to retail end use customers is critical to obtain low cost financing for the construction of new coal gasification facilities.

(4) Obtaining low cost financing for the construction of new coal gasification facilities is necessary to allow retail end use customers to enjoy the benefits of a reliable, reasonably priced, and long term energy supply.

TITLE 6. TAXATION ARTICLE 3.1. STATE TAX LIABILITY CREDITS CHAPTER 29. COAL GASIFICATION TECHNOLOGY INVESTMENT TAX CREDIT 6-3.1-29-19 Credit agreement; description; requirements

Sec. 19. (a) The corporation shall enter into an agreement with an applicant that is awarded a credit under this chapter. The agreement must include all the following:

(1) A detailed description of the project that is the subject of the agreement.

(2) The first taxable year for which the credit may be claimed.

(3) The maximum tax credit amount that will be allowed for each taxable year.

(4) A requirement that the taxpayer shall maintain operations at the project location for at least ten (10) years during the term that the tax credit is available.

(5) If the facility is an integrated coal gasification powerplant, a requirement that the taxpayer shall pay an average wage to its employees at the integrated coal gasification powerplant, other than highly compensated employees, in each taxable year that a tax credit is available, that equals at least one hundred twenty-five percent (125%) of the average county wage in the county in which the integrated coal gasification powerplant is located.

(6) For a project involving a qualified investment in an integrated coal gasification powerplant, a requirement that the taxpayer will maintain at the location where the qualified investment is made, during the term of the tax credit, a total payroll that is at least equal to the payroll that existed on the date that the taxpayer placed the integrated coal gasification powerplant into service.

(7) A requirement that:

(A) one hundred percent (100%) of the coal used:

(i) at the integrated coal gasification powerplant, for a project involving a qualified investment in an integrated coal gasification powerplant; or

(ii) as fuel in a fluidized bed combustion unit, in a project involving a qualified investment in a fluidized bed combustion technology, if the unit is dedicated primarily to serving Indiana retail electric utility consumers;

must be Indiana coal, unless the applicant wishes to assign the tax credit as allowed under section 20.5(c) of this chapter or elects to receive a refundable tax credit under section 20.7 of this chapter and the applicant certifies to the corporation that partial use of other coal is necessary to result in lower rates for Indiana retail utility customers; or

(B) seventy-five percent (75%) of the coal used as fuel in a fluidized bed combustion unit must be Indiana coal, in a project involving a qualified investment in a fluidized bed combustion technology, if the unit is not dedicated primarily to serving Indiana retail electric utility consumers.

(8) A requirement that the taxpayer obtain from the commission a determination under IC 8-1-8.5-2 that public convenience and necessity require, or will require:

(A) the construction of the taxpayer's integrated coal gasification powerplant, in the case of a project involving a qualified investment in an integrated coal gasification powerplant; or

(B) the installation of the taxpayer's fluidized bed combustion unit, in the case of a project involving a qualified investment in a fluidized bed combustion technology.

(b) A taxpayer must comply with the terms of the agreement described in subsection (a) to receive an annual installment of the tax credit awarded under this chapter. The corporation shall annually determine whether the taxpayer is in compliance with the agreement. If the corporation determines that the taxpayer is in compliance, the corporation shall issue a certificate of compliance to the taxpayer.

TITLE 6. TAXATION ARTICLE 3.1. STATE TAX LIABILITY CREDITS CHAPTER 29. COAL GASIFICATION TECHNOLOGY INVESTMENT TAX CREDIT 6-3.1-29-1 Tax credit applicants; women and minority business enterprises

Sec. 1. The general assembly declares that the opportunity for the participation of underutilized small businesses, especially women and minority business enterprises, in the coal gasification industry is essential if social and economic parity is to be obtained

by women and minority business persons and if the economy of Indiana is to be stimulated as contemplated by this chapter. A recipient of a credit under this chapter is encouraged to purchase goods and services from underutilized small businesses, especially women and minority business enterprises.

Kansas

CHAPTER 79. TAXATION - ARTICLE 2. PROPERTY EXEMPT FROM TAXATION 79-225. Property exempt from taxation; certain integrated coal gasification power plant property

(a) The following described property, to the extent herein specified, shall be exempt from all property taxes levied under the laws of the state of Kansas:

(1) Any new integrated coal gasification power plant property or any expanded integrated coal gasification power plant property.

(2) All property purchased for or constructed or installed at an integrated coal gasification power plant to comply with air emission standards imposed by state or federal law.

(b) The provisions of subsection (a) shall apply from and after purchase or commencement of construction or installation of such property and for the 12 taxable years immediately following the taxable year in which construction or installation of such property is completed.

(c) The provisions of this section shall apply to all taxable years commencing after December 31, 2005.

(d) As used in this section:

(1) "Expanded integrated coal gasification power plant property" means any real or tangible personal property purchased, constructed or installed for incorporation in and use as part of an expansion of an existing integrated coal gasification power plant, construction of which expansion begins after December 31, 2005.

(2) "Expansion of an existing integrated coal gasification power plant" means expansion of the capacity of an existing integrated coal gasification power plant by at least 10% of such capacity.

(3) "Integrated coal gasification power plant" has the meaning provided by K.S.A. 79-32,238, and amendments thereto.

(4) "New integrated coal gasification power plant property" means any real or tangible personal property purchased, constructed or installed for incorporation in and use as part

of an integrated coal gasification power plant, construction of which begins after December 31, 2005.

Key to Energy Security: Converting Coal to Gas to Synthetic Fuels to More Petroleum Production

By
Paul Metz, Director
Mineral Industry Research Laboratory
University of Alaska Fairbanks

Arctic Mining Symposium
03/12/10

Outline of Presentation

- Alaska's Energy Challenges
- Developing an Energy Plan
- Coal to Synthetic Gas and Liquid Fuels
- Carbon Dioxide and Enhanced Oil Recovery
- Financing the CTL Project
- Rails to Resources to Markets
- Summary of the Synergistic Effects of the Proposed Projects
- Conclusions

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- Decreasing oil production and revenues from the North Slope.
- Decreasing natural gas production from the Cook Inlet Basin.
- Increasing federal and state regulations that decrease incentives to find and develop more oil, natural gas & coal.
- Increasing federal and state regulations the increase the cost of petroleum refining.
- Alternate and lower cost sources of supply of natural gas to the contiguous states.
- Highly fluctuating energy costs as a function of worldwide demand and production of petroleum.
- Combined negative effects of costs and limited fuel supplies on the air cargo industry in Anchorage in particular and the transportation and tourism industries in Alaska in general.

- The KEY to developing cost effective and stable energy supplies and energy security for Alaska and the Nation is an Energy Plan that includes a Public Private Partnership between the state, the federal government, and the various industries that facilitates the FULL utilization of our coal, natural gas and petroleum resources.

- Natural Gas
  - Reserves in Prudhoe Bay and Kuparuk Fields – 26 Tcf.; Reserves in Pt. Thomson – 9 Tcf.
  - Total 35 Tcf

Gross Value ($ Billions)	at ($/mcf)
$210	$6
$280	$8
$350	$10
$420	$12
$490	$14

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- Petroleum
  - Original Oil in Place (OOIP) 67 Billion Barrels
  - Expected Total Recovery Without Enhancement – 22 Billion Barrels
  - Gross Value of 8 Billion Barrels of Enhanced Oil

Gross Value ($ Billions)	at ($/Barrel)
$320	$40
$480	$60
$640	$80
$800	$100
$960	$120
$1,120	$140
$1,280	$160

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- Petroleum
  - Original Oil in Place (OOIP) 67 Billion Barrels
  - Expected Total Recovery Without Enhancement – 22 Billion Barrels
  - Gross Value of 12 Billion Barrels of Enhanced Oil

Gross Value ($ Billions)	at ($/Barrel)
$480	$40
$720	$60
$960	$80
$1,200	$100
$1,440	$120
$1,680	$140
$1,920	$160

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- Coal
  - Resources widely disbursed in Alaska but majority of high rank on the western end of the North Slope.
  - U.S.G.S. recent resource assessment – 5.5 trillion tons with majority of resources high rank coals @ 15,000 Btu/lb.
  - Magnitude of resource: 50% of U.S. electrical energy generated with coal; at 100% coal generation, Alaska could sustain the U.S. for at least 2,500 years!

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Gross Value of Alaska Coal

Resources at Various Price Levels

Price ($/ton)	Gross Value of 5.5 trillion tons ($ trillions)
40	220
60	330
80	440
100	550
120	660
140	770
160	880
180	990

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[illegible]

- Coal
  - Estimated coal resources of Alaska is at least 5.5 trillion tons with majority high rank coal @ 15,000 Btu/lb.

  Total energy in proven gas reserves – 3.5×10^{16} Btu.
  - Total energy in remaining oil in place – 3.9×10^{17} Btu.
  - Total energy in estimated coal resources 1.7×10^{20} Btu. (10,000 x that in the natural gas).

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Synergism of Three Major Energy Projects

- Alaska In-State Natural Gas Pipeline (ENSTAR "Bullet Pipeline")
- Coal to Liquids Plant (Synthetic Fuels Plant as under investigation by Fairbanks Economic Development Corporation)
- Carbon Dioxide Enhanced Oil Recovery of Stranded Heavy Oil in Prudhoe Bay and Kuparuk Oil Fields.

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[illegible]

- Cook Inlet Basin has supplied gas for electric power generation, space heating in the Anchorage area, industrial uses in the Kenai area, and for export markets.
- Current supplies will be depleted by 2015 with current shortages during peak demand periods.
- Expected cost to discover and develop new gas reserves in the Basin: $5-6 billion if the price of gas is deregulated.
- Current and potential market in the Fairbanks area - less than 10% of the needs in south-central Alaska.

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About the ENSTAR Pipeline

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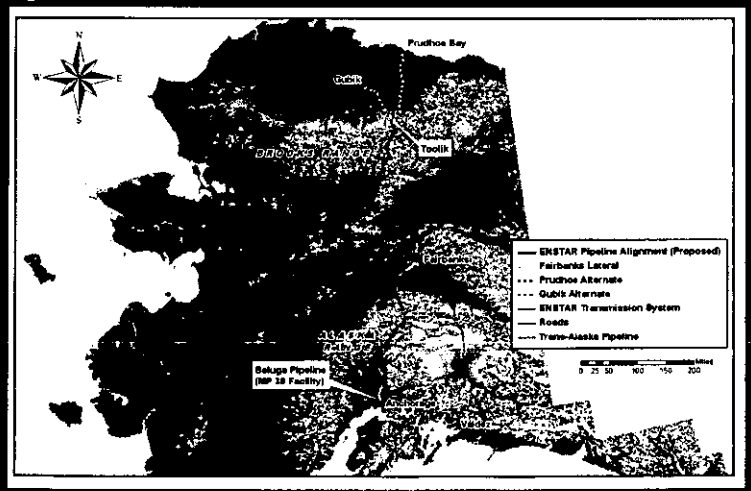
About the ENSTAR Pipeline



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- Estimated capital cost of 24 inch (0.5 Bcf/d) natural gas pipeline from Gubik 'Gas Field' (Expected dry pipeline quality gas) to Fairbanks and Anchorage – $3.8 billion.
- Estimated cost to discover and develop 30 year supply of gas from Gubik - $1.0 billion (Anadarko Petroleum).
- ENSTAR target date for gas to Anchorage is 2015.
- Total of Anchorage, Kenai, and Fairbanks markets significantly less than 0.5 Bcf/d.
- Project needs large commercial user to be economically feasible – Hence FEDC Coal to Liquids Project.

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Coal to Liquids Project

- Estimated capital cost of 40,000 barrel per day plant: $4.6 billion.
- Products: Jet-A and diesel fuel.
- Estimated return on capital at an average price for these synthetic fuels of $2.57/gal.:12%.
- During 2008 diesel peaked at approximately $5.00/gal. and over the next decade it is expected that the price will return to this level.
- Major benefit in the long term coal conversion is the long term price stability of coal, large domestic resources of coal, and thus no adverse impact on trade balance and the value of the dollar.

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Major Environmental Concern with Respect to Coal Combustion

- Carbon Dioxide emissions – 3.6 tons for every ton of coal combusted.
- Potential technologies for CO_2 sequestration – most expected to result in significant 25% or more increased cost of energy produced.
- Carbon Dioxide enhanced oil recovery (see Schlumberger web site for new CO_2 sequestration projects office in Calgary, Alberta.
- North Slope producers have utilized water flooding and CO_2 injection to enhance oil recovery on the Alaska North Slope since 1980s.

U.S. Department of Energy Investigations of CO_2 Enhanced Oil Recovery

- See Advanced Resources International Report, 2005.
- Major constraint to CO_2 enhanced oil recovery on the North Slope is the availability of large volumes (1 Tcf/yr) of CO_2 at costs not exceeding 5% of the well price of oil.
- Coal to Liquids Plant operating at 200,000 barrels per day could produce this volume of CO_2 .

Rates of Return for 200,000 b/d Plant at

Oil Price	Sale of CO_2 (@5% Oil Price)
$40	7.3%
$60	12.4%
$80	17.1%
$100	21.6%
$120	26.0%
$140	30.4%
$160	34.8%
$180	39.1%

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Rates of Return for 200,000 b/d Plant at

1/8 royalty on 8 billion barrels of oil

Oil Price	Sale of CO_2 (@5% Oil Price)
$40	15.1%
$60	23.1%
$80	31.0%
$100	38.7%
$120	46.5%
$140	54.2%
$160	62.0%
$180	69.7%

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Rates of Return for 200,000 b/d Plant at

1/8 royalty on 12 billion barrels of oil

Oil Price	Sale of CO_2 (@5% Oil Price)
$40	18.6%
$60	28.2%
$80	37.7%
$100	47.1%
$120	56.5%
$140	65.9%
$160	75.4%
$180	84.5%

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Financing the Coal-to-Liquids Plant

- ARRC Tax Exempt Non-Recourse Bonds
- Requirement – long term contract with North Slope Producers for the sale of carbon dioxide at the CTL Plant Site.
- 12 inch line to NS estimated to cost $2.4-$2.8 billion.
- Advanced Resources International used hurdle ROR of 15% and 25% based on an oil price of $25/barrel and tax incentives of $10/barrel thus an effective well-head price of $35/barrel.
- This analysis assumes a minimum oil price of $40/b and that the tariff on the CO_2 line will not exceed $5/barrel of oil recovered which is very conservative.

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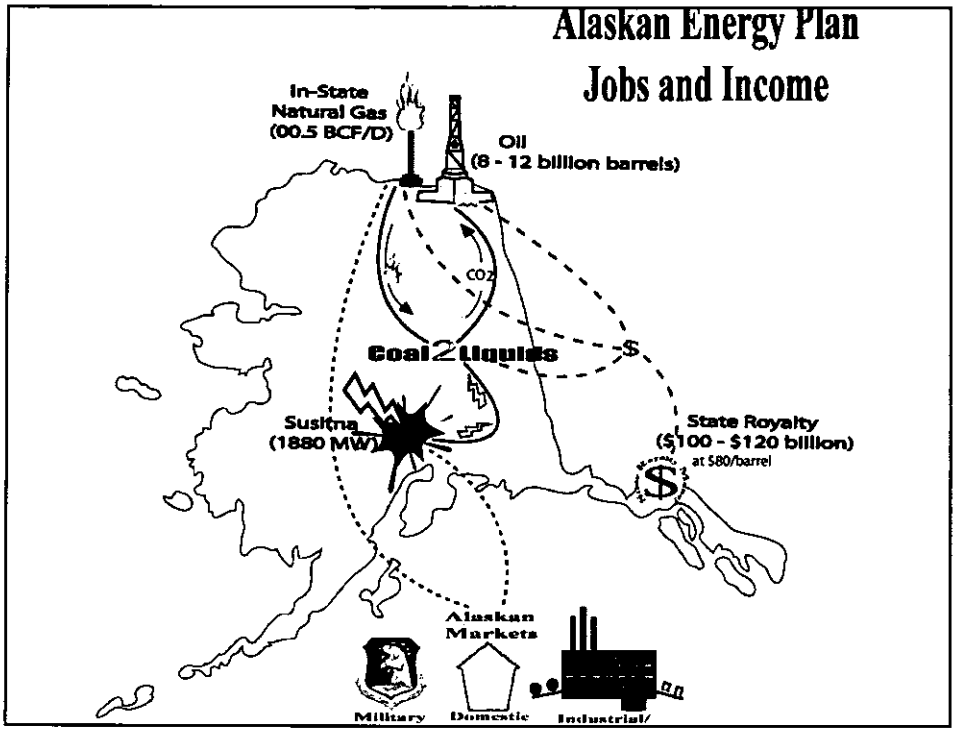

Summary of Synergistic Effects of the Proposed Projects

- Maintenance of higher levels of oil production and revenues from the North Slope for another 30 years.
- Replacement of Cook Inlet natural gas production with North Slope gas for both Anchorage and Fairbanks.
- Supplement or replacement of North Pole refinery production with low sulfur synthetic fuels @ 200,000 barrels per day.
- Availability of in-state gas without constraints of markets in the contiguous states.
- Stable fuel supplies and prices as a function of the large in-state supply of coal.
- Long term stable fuel supplies and prices for the air cargo and other transportation systems in Alaska.

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CONCLUSION

- NOT TAPS FOR TAPS FOR AT LEAST ANOTHER 30 YEARS

Concentration of Carbon Dioxide in the Atmosphere During the Phanerozoic

- Complex life forms developed during the Phanerozoic time.
- This time interval includes the last 600 million years of Earth history.
- For 85% of the time during this interval of Earth history, carbon dioxide concentrations in the atmosphere were two or more times greater than present levels.
- Extreme levels of carbon dioxide in the atmosphere during this time probably exceeded current levels by 2000%.
- These extreme levels did not result in irreversible global warming or mass extinctions.
- Carbon dioxide in the atmosphere has increased from approximately 250 to 330 ppm over the past 50 years (30%).
- Even the most extreme predictions of anthropogenic carbon emissions over the next 100 years do not exceed two times current levels.