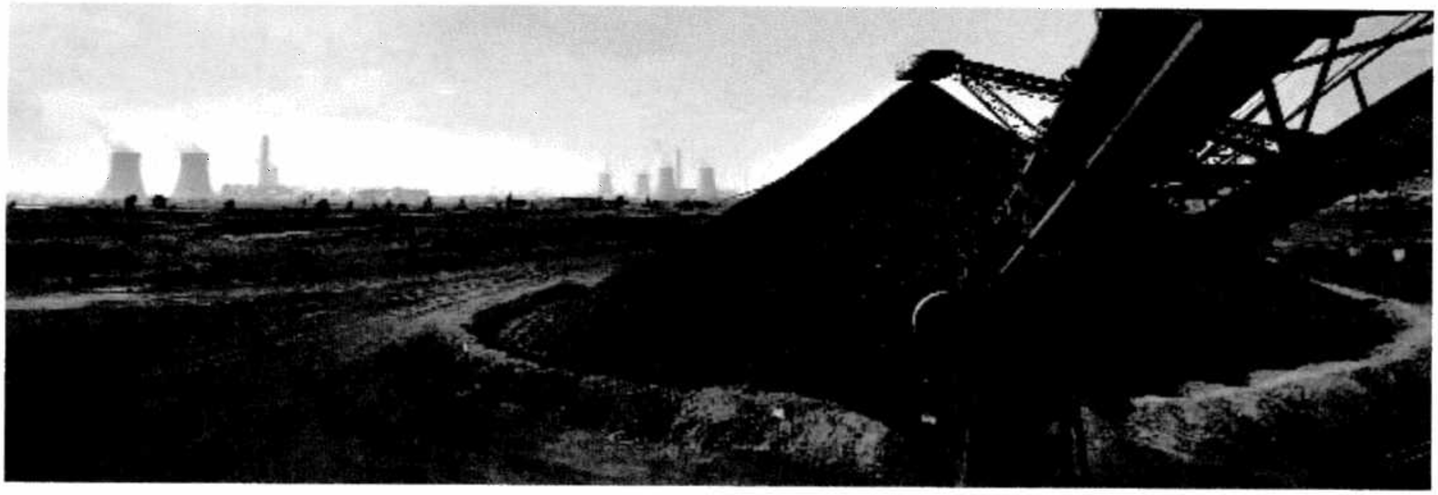
sasol Slurry Phase Distillate ™ process



Converting natural gas into high-quality diesel

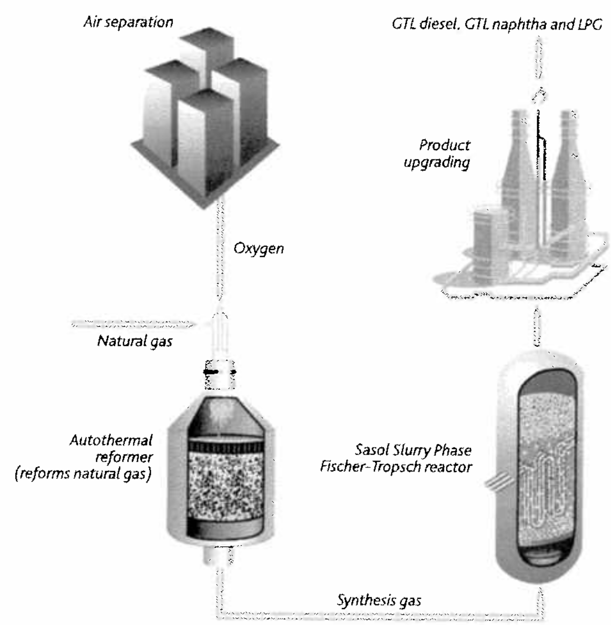
The fully integrated, three-step Sasol Slurry Phase Distillate ™ (Sasol SPD ™) process dates back to the 1980s when Sasol developed its low-temperature Slurry Phase Fischer-Tropsch reactor at Sasolburg. Combined with a proprietary iron- or cobalt-based catalyst, this technology allows for the creation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

sasol
reaching new frontiers

leading the way in Qatar and Nigeria

Sasol's first two GTL projects

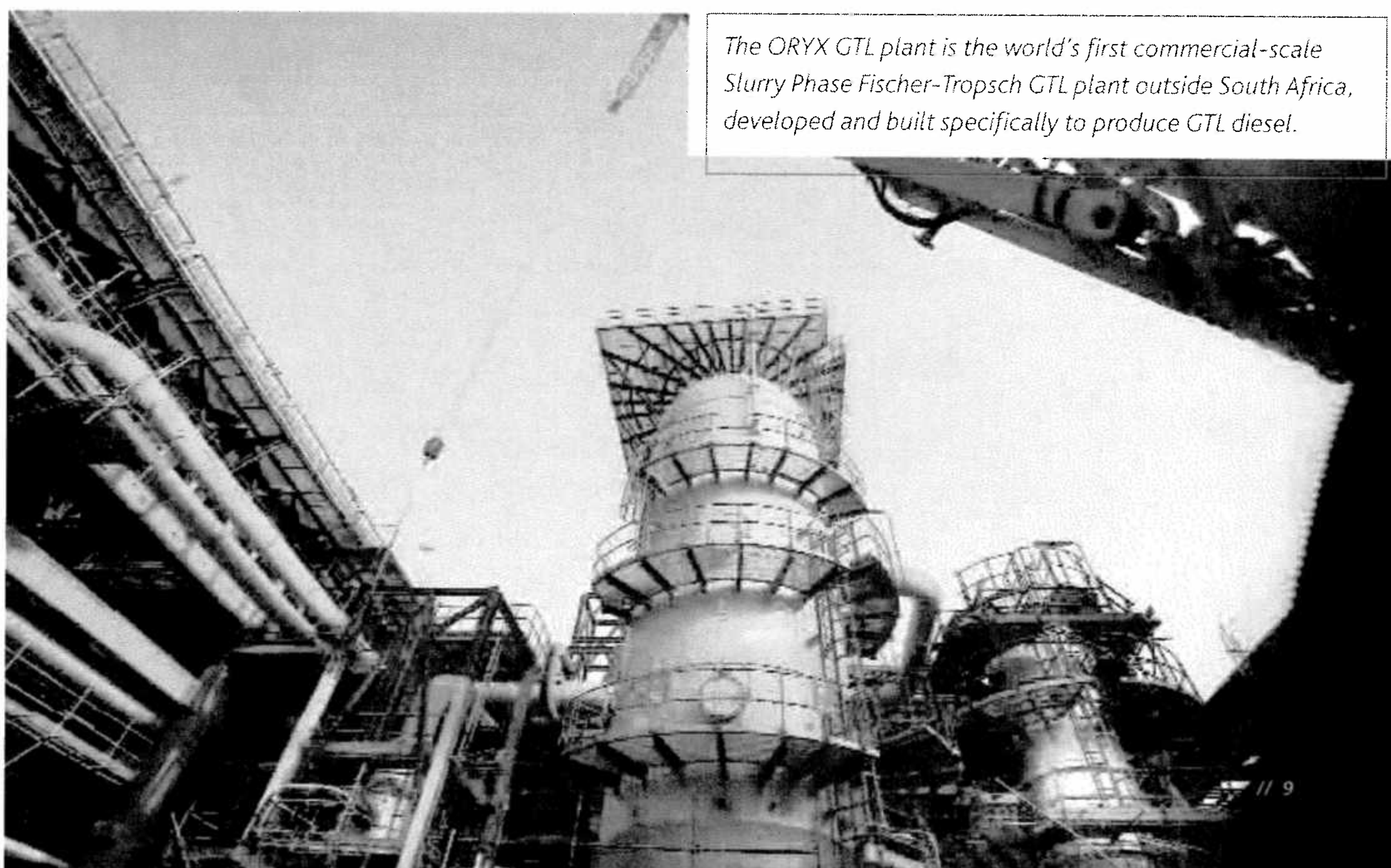
Sasol inaugurated its first GTL project, the ORYX GTL venture, at Ras Laffan on the north-eastern seaboard of Qatar, in partnership with Qatar Petroleum, in June 2006.

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.

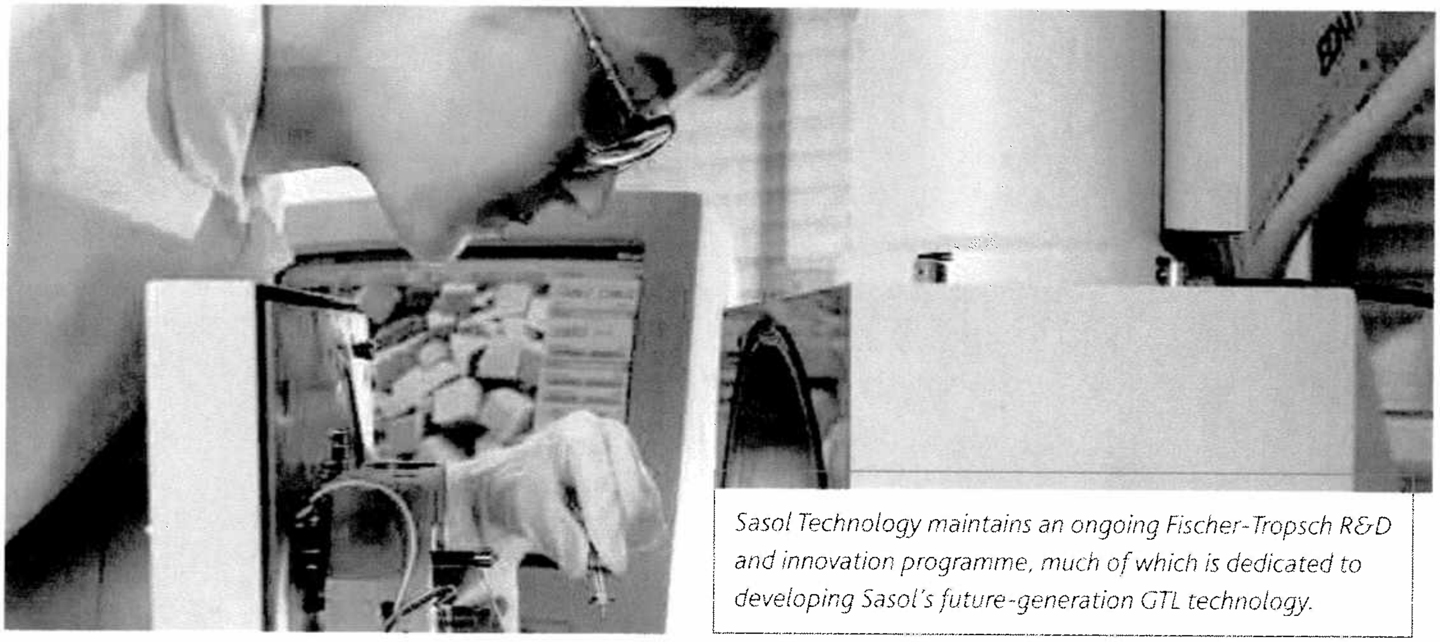
To complement the ORYX project, Sasol and Sasol Chevron are working with the National Nigerian Petroleum Corporation and Chevron Nigeria Limited to develop another 34 000 b/d GTL project, the EGTL plant at Escravos in the Niger Delta. Construction work commenced in 2006 and the plant is expected to go 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

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 C_nH_{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

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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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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.

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

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

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

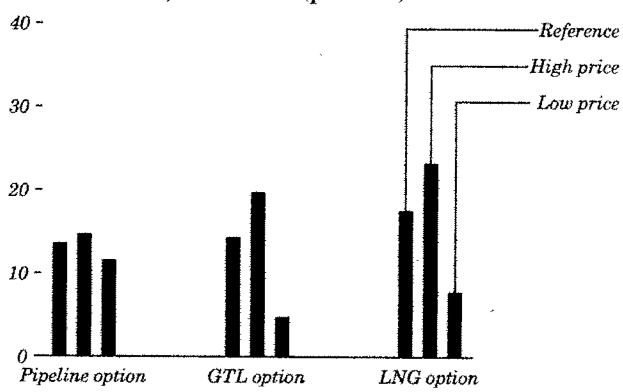
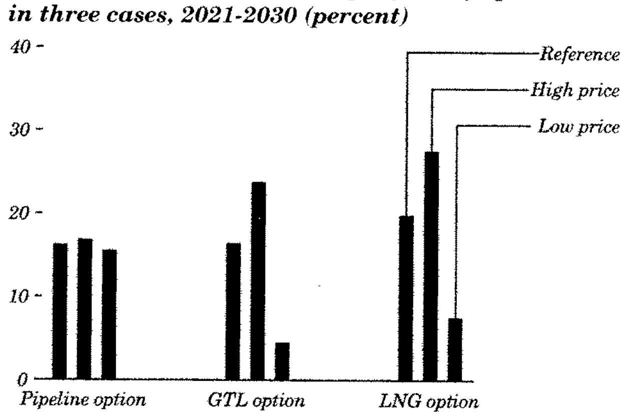


Figure 21. Average internal rates of return for three Alaska North Slope natural gas facility options in three cases, 2021-2030 (percent)



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.

<u>Facility Cost Assumptions</u>

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.

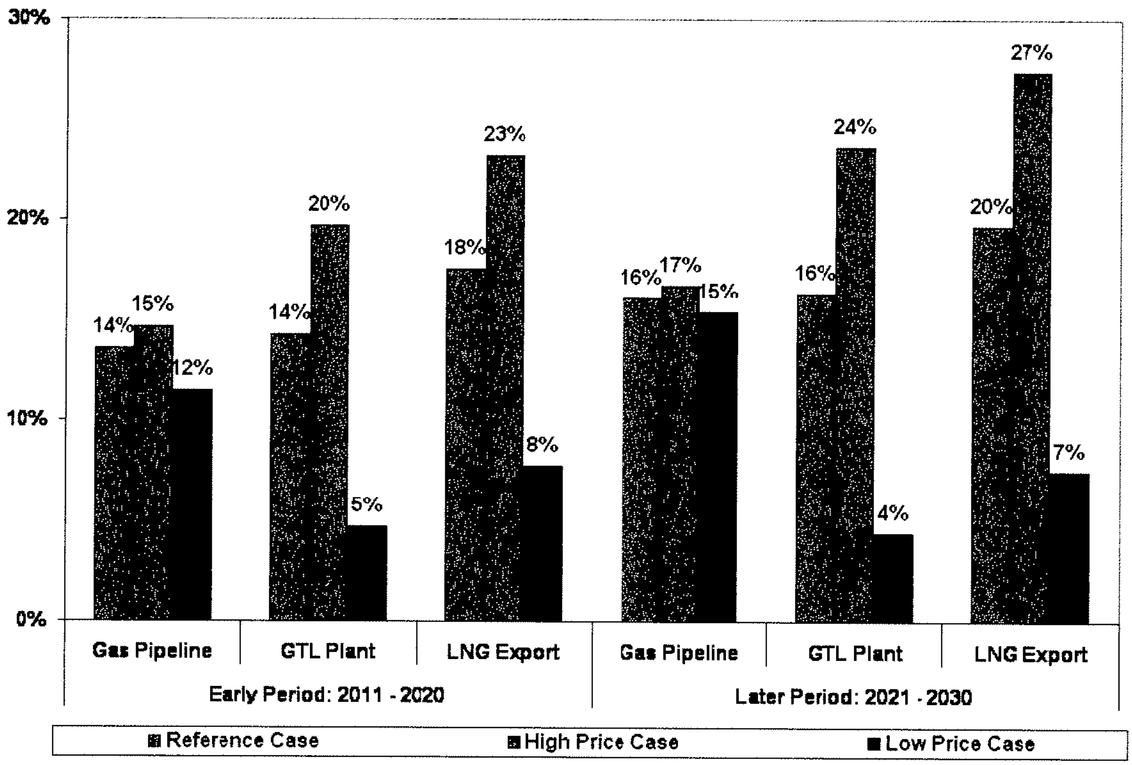
Within NEMS, natural gas price increases are held in check by declining natural gas demand (especially within the electric power sector) and by increasing natural gas drilling, reserves, and productive capacity. Similarly, natural gas price declines are held in check by an increasing gas demand and by 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.

primary alternatives points to an Alaska gas pipeline as being the most likely real-world outcome at the present time.

Beluga Coal Gasification Feasibility Study

DOE/NETL-2006/1248

Phase I Final Report

July 2006

Beluga Coal Gasification Feasibility Study

DOE/NETL-2006/1248

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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.

[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.

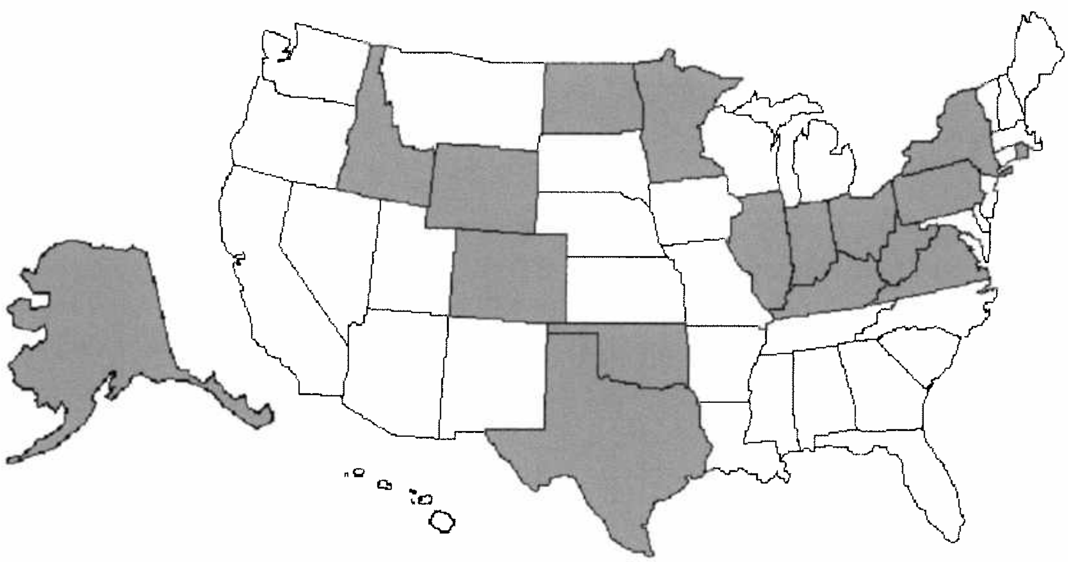

Fig. 1 – States with current incentives for advanced coal projects (Alaska, Colorado, Idaho, Illinois, Indiana, Kentucky, Minnesota, New York, North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, Texas, Virginia, West Virginia, and Wyoming) are shaded.

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

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[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]

[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 legislation 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

[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.