The Business Case for Coal Gasification with Co-Production

An Analysis of the Business Risks, Potential Incentives, and Financial Prospects, with and without Carbon Sequestration

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SCULLY CAPITAL

December 2007

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ACKNOWLEDGMENTS

The Department of Energy's (DOE) Office of Policy and International Affairs (PI) is greatly appreciative of the contributions of all of the organizations and experts who have contributed to this study, along with the sponsorship of the PI management team, Karen Harbert and Stephen Eule. This report is the product of a virtually unique co-sponsorship by a diverse group of government agencies and private-sector associations. The analysis establishes the basis for mutual understanding of the commercial potential of an advanced technology area and frames the parameters for co-management of risks to early commercial projects. As discussed in the Introduction, DOE's funding collaborators include:

- The Department of Defense, Air Force (DoD)
- The Electric Power Research Institute (EPRI)
- The American Chemistry Council (ACC)
- The Gasification Technologies Council (GTC)
- The Fertilizer Institute (TFI)
- The American Iron and Steel Institute (AISI)

In addition, the Environmental Protection Agency provided sponsorship for one portion of the study in order to broaden its scope to include analysis of co-production facilities with carbon dioxide sequestration.

The study could not have been completed without the contributions of Dr. David B. Gray, director of energy systems analysis for Noblis, Inc. (formerly Mitretek Systems) and his funding sponsor, the Southern States Energy Board. Dr. Gray provided in advance of its publication a proprietary engineering analysis of a reference co-production facility that became the basis for the "Reference Plant" used in performing financial and risk analyses in this study. The Noblis reference co-production facility was the most complete and advanced pre-FEED plant design in existence outside of companies involved in building and operating such facilities when this study began.

As described in the Introduction, a number of experts drawn from the sponsoring organizations and DOE's Office of Fossil Energy guided the study team under the leadership of PI's David R. Berg. The study benefited immensely from the invaluable inputs provided by these government, industry, and consultant experts, who included:

- DoD (OSD, AF, Navy, DLA): Bill Harrison, Mike Aimone, Paul Bollinger, LT COL Anne Gorney, Mike McGrath, CAPT Marv Wenberg, Dr. Alan Roberts, Richard Connelly, Ted Sheridan, Pam Serino, Larry Ervin, Pat Gaston, Andrew Pittman, Mark Bednar

- EPA: Anna Wood, Ben Hengst, Stacey Coburn, Bob Wayland, Sikander Khan, Dan Chartier, Donna Perla, Dwight Alpern, Simon Mui, Lester Wyborny, Larry Gonzalez, Anhar Karimjee
- EPRI: Neville Holt, John Novak, Jack Parkes
- ACC: Owen Kean
- GTC: Jim Childress
- TFI: Everett Zillinger
- AISI staff
- DOE/FE: Lowell Miller, Darren Mollot, Jay Braitsch, Dan Cicero, Ed Schmetz

DOE also recognizes the performing team from Scully Capital Services, Inc., which completed in outstanding fashion an extremely difficult set of contractual requirements on a very tight budget, while working under the oversight of no less than eight sponsoring organizations. The Scully analytic team included Brian Oakley, Andrew Paterson, Sameer Parikh, and Jeanne Kim.

Any errors in this document are the responsibility of the study leads at DOE and Scully Capital and not the broader study team.

EXECUTIVE SUMMARY

I. OVERVIEW

The Business Case for Coal Gasification with Co-Production quantifies the economics of coal gasification with co-production in the United States, examines the risks associated with developing large-scale co-production facilities, and evaluates the cost-effectiveness of incentives that could improve the financial prospects of early commercial projects. It explores, but does not advocate, any policies.

The total financed cost of plants (in late-2005 dollars, +/- 30 percent) ranges from \$3.3–\$3.7 billion, depending on type of coal and the use of carbon handling equipment. (It should be noted that capital costs have escalated since the development of these estimates.) A plant using bituminous coal consumes almost 18,000 tons per day to produce about 32,500 barrels per day of diesel-equivalent Fischer-Tropsch (FT) fuels (in the form of FT diesel and naphtha) and 725 MWe of electricity, most of which is consumed within the plant. Sales of FT fuels from this plant must be priced around \$73 per barrel, or \$56 per barrel in crude-equivalent price, to achieve a target internal rate of return of 19 percent. Carbon dioxide compression adds about \$4.00 to this FT fuel price, and sequestration another \$6.00, for a total increase of \$10.00 (see Exhibit ES.7). Carbon dioxide sales for enhanced oil recovery may offset part or all of this increase. However, because the separation of carbon dioxide from other gas streams is inherent to co-production plants and minimal incremental cost is incurred for carbon capture, these plants will have a lower cost for carbon sequestration than most other fossil-based projects. As a result, co-production plants may be particularly well-suited to early commercial tests of the operability and cost of large-scale carbon capture and sequestration.

The results of the analysis suggest that coal gasification with co-production projects could be competitive and assured sources of transportation fuels and other products over the long term. However, energy prices have exhibited price volatility over at least the past 30 years and, as a result, credit rating agencies utilize a conservative long-term crude oil price expectation that reflects the likelihood that energy prices will fall, for periods of time, significantly below today's energy prices. As a result, early commercial Reference Plants will require the support of purchase agreements and, potentially, incentives, even though co-production plants may offer products at prices that are attractive in today's markets. Projects face a number of key risks and policy challenges that affect their ability to attract financing and near-term prospects:

- **Price volatility in energy markets —** Given that coal gasification with co-production plants will compete directly with crude oil imports and natural gas, the historic volatility of crude oil and natural gas prices represents a key uncertainty with regard to their economic viability. Accordingly, early commercial plants will require a long-term off-take arrangement with a creditworthy counterparty facilitate financing.

- **High and escalating capital costs plus construction uncertainties —** High capital costs, rapidly escalating construction costs, and the lack of engineering and construction contracting standards for co-production facilities, including performance warrantees, are and will remain a challenge for the foreseeable future. High capital costs ensure that the products of early commercial co-production plants, in most cases, can compete with crude oil-based products over the long term only with the support of a purchase agreement and/or other incentives.
- **Uncertainties about carbon policy —** Concerns about carbon dioxide emissions will force project sponsors to carefully evaluate opportunities for carbon dioxide sequestration and enhanced oil recovery with sequestration. This analysis suggests that compressing, transporting, and permanently sequestering carbon dioxide could increase the cost of synthetic fuel by approximately $10.00 per barrel. Even with this cost increase, some co-production plants that sequester carbon dioxide via enhanced oil recovery (EOR) may be able to operate competitively, but incentives may be needed if the co-production plants are unable to sell the carbon dioxide at a comparable price.

Although commercial coal gasification with co-production facilities exist (internationally and, at nearly full scale, in the United States), the scale of new plants and the introduction and integration of new technologies will continue to present financing challenges until one or more new facilities have been successfully completed and are operational. Given the country's vast coal reserves, the cost advantage co-production plants are likely to have in sequestering carbon dioxide, and the demonstrated commercial track record of coal gasification technologies, coal gasification with co-production affords the nation an opportunity that is worthy of careful consideration. A variety of coal types, plant configurations, and site-specific attributes will influence the technical and economic feasibility of any coal gasification with co-production plant. Moreover, growing concerns about carbon dioxide emissions associated with any fossil-based project and regulatory issues concerning carbon dioxide transportation and storage add to the risks facing developers of early commercial projects. Thus, the business risks associated with these facilities may impinge most on early commercial projects.

Given these uncertainties, it appears that most early commercial projects will require purchase agreements and, potentially, government incentives tailored at the state and national level to mitigate concerns related to long-term market risks and near-term technology risks. The study reached the following major conclusions about the various risk mitigation techniques studied, including one encouraging carbon management:

- **Purchase agreements (PA)** for a substantial portion of a plant's production are necessary for managing price volatility in crude oil and natural gas markets, as well as other risks, because they assure the cash flows needed to satisfy debt servicing requirements for plants built with a project finance structure (versus a plant backed by the strength of a company's balance sheet). A purchase agreement or rate-basing arrangement for electricity produced in a plant can complement a PA for FT fuels, but is unlikely to be sufficient alone. PAs alone could be sufficient in enabling construction and operation of some co-production plants, but only if they involve a sufficient portion of a plant's production, are of sufficient term, and are placed by a creditworthy counterparty. The study assumes the placement of a PA with a creditworthy counterparty as integral to the financial structure of a project. PAs involving the Federal government as primary off-taker have a large budgetary impact compared to government tax and credit incentives.

- **Tax incentives** can reduce output pricing and may positively impact project creditworthiness. Investment tax credits (ITCs) decrease the effective cost of equipment and production-based tax credits (PTCs) reduce the marginal revenue requirement to produce FT fuels. However, both ITCs and PTCs have a large budgetary impact and may not address key project risks effectively.
- **Loan guarantees** can provide a large reduction in FT fuel price if structured properly. They can improve the prospects of obtaining financing for a project and reduce interest rates paid, demonstrate a greater benefit than tax incentives, and have a lower budgetary impact, particularly for projects using a project finance structure, although they do expose the government to potential loan payment defaults in excess of credit subsidy payments. Loan guarantees help to offset technology, construction, and market risks associated with a project.
- **A tax credit based on the amount of carbon dioxide sequestered** (of \$11–\$12 per ton sequestered) may be the optimal incentive for encouraging sequestration by co-production plants because it directly offsets the cost of sequestration. Other tax incentives and loan guarantees can be used to reduce the cost of sequestration equipment, but they usually will not encourage the operation of this equipment. The cost implications of sequestration make the unaided construction and operation of co-production plants with sequestration unlikely. A tax credit of this type will have a large budgetary impact.

In summary, the construction and operation of early commercial co-production plants is unlikely without a purchase agreement and, potentially, the support of incentives. The type and level of incentives will vary depending on site-specific factors, including the terms of the purchase agreement. Further, if projects that sequester the carbon dioxide produced in plant operations are built in the absence of sequestration regulations, an incentive will be needed to offset the cost of sequestering the carbon dioxide.

II. INTRODUCTION

The Energy Policy Act of 2005 (EPAct 2005), the National Energy Policy, and the Advanced Energy Initiative call for greater use of domestic resources to improve energy security in the United States. Price increases and volatility in international and U.S. crude oil and natural gas markets, along with increasing demand for energy in emerging economies, highlight the value of using lower priced and relatively plentiful domestic options to improve U.S. energy security. Foremost among available options is increased use of coal, the country's largest fossil fuel reserve with more than 250 years of supply at current usage rates.

The gasification of coal and other domestic energy sources, including biomass, to produce electricity, transportation fuels, chemicals, fertilizer, pipeline-quality synthetic gas, and other products can be broadly categorized as "Coal Gasification with Co-Production" (hereinafter referred to as co-production and industrial gasification). Co-production is important to several U.S. manufacturing industries, such as nitrogen fertilizer, chemicals, glass, cement, and iron and steel, which rely on natural gas as an energy source and/or feedstock, and it may be an alternative source of domestic, stably priced liquid transportation fuels, such as aviation fuel and clean diesel. The business risks, economics, and financing bottlenecks of constructing and operating co-production plants — particularly those that make transportation fuels, electricity, and naphtha — are the subjects of this project. The project team had hoped to analyze co-production plants that make a wider slate of products, but engineering design and cost data for other product slates are not available.

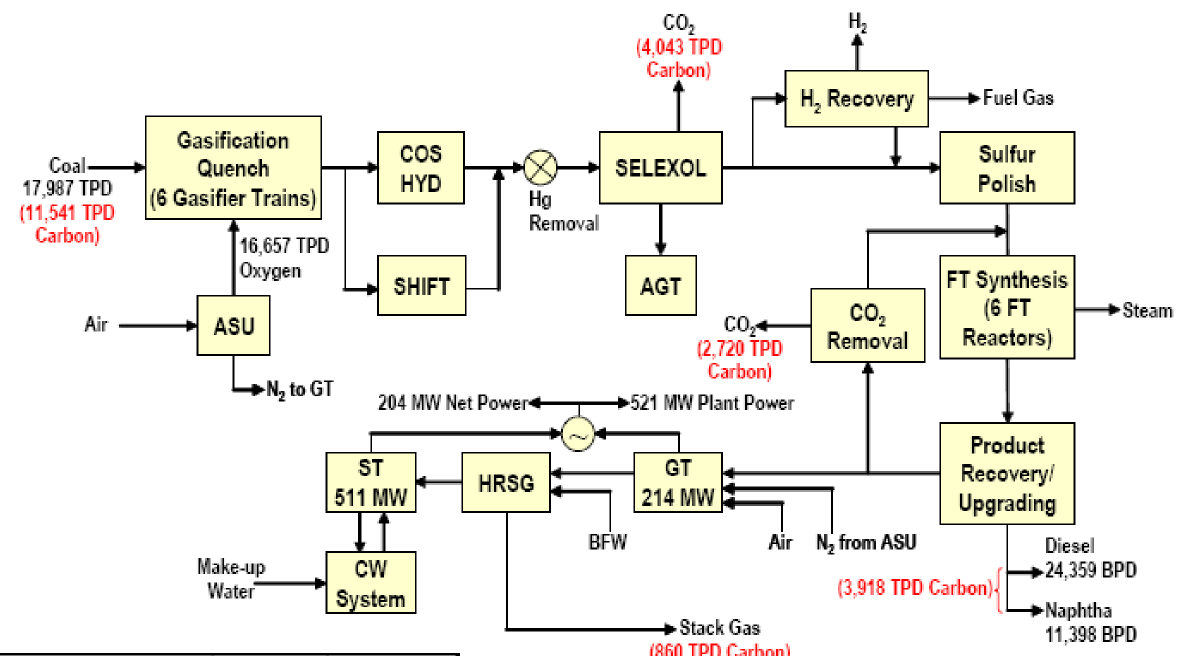
A discussion of increased coal use must take into account attendant environmental impacts, including increased emissions of carbon dioxide, the primary greenhouse gas. Importantly, the separation of carbon dioxide from other gas streams is inherent to co-production plants, so minimal incremental cost is incurred for carbon capture. This feature results in a lower cost for carbon sequestration relative to most other fossil-based projects. As a result, early commercial co-production plants are particularly well-suited to tests of the operability and cost of large-scale carbon capture and sequestration. Finally, the gasification of coal with co-production of a range of products offers the prospect of reducing the overall environmental footprint associated with power production from coal compared to that of conventional technologies for generating electricity.[1]

[1] "An Environmental Assessment of IGCC Power Systems" Jay A. Ratafia-Brown, Lynn M. Manfredo, Jeff W. Hoffmann, Massood Ramezan (Science Applications International Corporation) and Gary J. Stiegel (U.S. DOE/National Energy Technology Laboratory) Presented at the Nineteenth Annual Pittsburgh Coal Conference, September 23–27, 2002.

Reference Co-Production Plants

Exhibit ES.1 provides the plant schematic and carbon balance for a reference co-production plant that uses bituminous coal to produce synthetic fuels and electricity. As the exhibit illustrates, coal gasification converts coal into "syngas," a gas rich in carbon monoxide and hydrogen. Carbon dioxide, sulfur, mercury, slag, and other by-products of gasification are amenable to capture, collection, and reuse (or, in the case of carbon dioxide, long-term sequestration), and nitrogen oxides are produced only at low levels. Separated carbon dioxide, once compressed and transported, can be stored permanently in underground geologic formations or used for enhancing recovery of hydrocarbons from depleted oil fields. EOR can be conducted with or without permanent sequestration of the carbon dioxide.

Exhibit ES.1: Schematic and Carbon Balance for Bituminous Coal Reference Plant



Carbon (C)	Tons C	% C
From Selexol	4,043	35%
Post - FT	2,720	24%
In fuels	3,918	34%
In stack gas	860	7%
Total carbon	11,541	100%
Total coal	17,987	
Carbon in coal	64%	by mass

Source: Mitretek

Coal-derived syngas can be used in many ways, including serving as a feedstock for a range of chemical processes and powering a combined cycle gas turbine to produce electricity. In this illustration, the Fischer-Tropsch (FT) process catalytically converts syngas produced in gasifiers into a wax and refines the wax to produce FT fuels for transportation, such as FT diesel or FT jet fuel, plus naphtha. If a large portion of the carbon dioxide produced in the gasification and fuel conversion processes is permanently sequestered, the lifecycle carbon emissions of FT fuels become approximately the same as those from conventional petroleum-based fuels.[2] Although FT fuels can be produced from natural gas (gas-to-liquids, or GTL), this report focuses on coal because of the large domestic supply and low cost per BTU.

Project Sponsors and Performing Team

In March of 2006, the Department of Energy's (DOE) Office of Policy and International Affairs, the Department of Defense (DoD), and several industry associations teamed to sponsor this multi-phase and multi-report analysis by Scully Capital Services, Inc. (Scully Capital). The goal of the analysis is to enhance understanding of the business risks, economics, and financing challenges involved with co-production plants, with and without carbon sequestration, and of the applicability and cost of a range of incentives that governments, particularly, could apply to early commercial co-production facilities. Industry sponsors include the Electric Power Research Institute (EPRI), American Chemistry Council (ACC), Gasification Technologies Council (GTC), The Fertilizer Institute (TFI), and the American Iron and Steel Institute (AISI). In addition, the Environmental Protection Agency (EPA) sponsored one portion of the study, an analysis of the costs associated with, and incentives for gaining, the potential carbon benefits of co-production. This addition broadened the scope of the project to include analysis of co-production facilities with carbon dioxide sequestration. The entire study, therefore, examines plants both without and with sequestration.

David Berg of DOE's Office of Policy and International Affairs initiated the project and provided oversight and guidance. He also led the Integrated Project Team (IPT) that provided input to, and reviews of, work products. The IPT was comprised of the sponsors of the project and DOE's Office of Fossil Energy.

III. OVERVIEW OF PROJECT ELEMENTS

The project was conducted in multiple phases, and individual reports were prepared after each phase. The project phases included:

- **Reference Plants and sensitivity testing** — The development of technical and financial assumptions of reference bituminous coal and lignite co-production

[2] Unpublished paper. Department of Energy. National Energy Technology Laboratory (NETL). August 2007. Lifecycle carbon emissions may be at least five percent less than those from conventional petroleum-based fuels depending on the type of production process used in the plant, the plant's source of electricity, and the type of oil used in the comparison.

plants (Reference Plants), analysis of the financial prospects of Reference Plants, and sensitivity testing of key input and output variables.

- **Alternative Plants and sensitivity testing** — The development of technical and financial requirements for Alternative Plants with increased electricity output, analysis of the financial prospects of these plants, and sensitivity testing of key input and output variables.
- **Business risk analysis** — The business risks that influence the financeability and operation of co-production plants.
- **Analysis of financial incentives** — An analysis of the differing effects and cost of a range of incentives on the economics and financeability of co-production plants.
- **Financial impacts of sequestering carbon dioxide and analysis of incentives for sequestration** — An examination of the financial implications of sequestering carbon dioxide from co-production plants and an analysis of incentives that encourage sequestration and offset the high costs of early commercial sequestration operations.

IV. FINDINGS

A. Reference Plants and Sensitivity Testing

Results of Reference Plant Analysis

Technical assumptions used in this study are derived from the American Energy Security Study (AES Study) sponsored by Southern States Energy Board (SSEB)[3] and a technical analysis conducted by Mitretek (now Noblis). Importantly, the cost estimates provided by Mitretek were preliminary in nature and could vary by +/- 30 percent.[4] It is important to note that, in the two years since Mitretek developed these cost estimates, sources consulted for this study indicate that the cost of capital-intensive projects have escalated significantly (to as much as 135–175 percent of base costs, although some widely used indexes of equipment and construction cost grew at lesser rates over this period[5]). To evaluate the significance of capital cost increases, Scully Capital performed sensitivity testing which showed, for example, the effect on FT fuel price of an increase of 25 percent in capital costs. The analysis does not take into account potential site-specific characteristics that could affect total plant cost. So, it is important

3 "American Energy Security – Building a Bridge to Energy Independence and to a Sustainable Energy Future" The Southern States Energy Board. July 2006. "SSEB Study" (www.sseb.org)

4 ibid. Appendix D. Page 16.

5 The Marshall & Swift Equipment Cost Index – Electric Power Sector increased by 5.6% in 2005, 4.7% in 2006, and 5.5% in 2007. The Chemical Engineering Plant Cost Index increased by 5.4% in 2005, 6.8% in 2006, and 5.4% in 2007.

to consider these results as preliminary ranges that would be further refined based on a project's site-specific characteristics and detailed engineering.

The Reference Plant analysis utilizes a non-recourse project financing structure in which a project "stands on its own" in the sense that its cash flows provide the underpinnings of its creditworthiness. Developers and financiers indicated that this type of structure would likely be utilized for most early commercial plants. Importantly, a non-recourse project financing structure insulates project sponsors from the full risk of the project, allowing risks to be shared by several participants in the project. The analysis assumes that, to assure stable cash flows and repayment of project debt, a purchase agreement is placed with a creditworthy counterparty for a substantial portion of the production of a Reference Plant.

A financial analysis for the Reference Plant that uses bituminous coal provides the basis for sensitivity analyses and the analysis of incentives. Exhibit ES.2 provides an overview of the financial results for this Reference Plant, including the prices it needs to obtain for primary outputs.

Exhibit ES.2: Overview and Price Results for Primary Outputs of the Reference Plant Using Bituminous Coal

Input Characteristics	
Tons of Coal Per Day	17,987
BTU Value of Bituminous Coal	11,800
Price of Coal Delivered	$36 / Short Ton
Output Characteristics at Capacity	
FT Liquids (bpd)	
FT Diesel	24,359
Naphtha	11,398
Total: Diesel-Equivalent FT	32,502
Electricity Production	
Gross (MWe)	725
Net (MWe)	257
Net (MWe) with Carbon Capture and Compression	205
Output Pricing	
At 19% IRR	
FT Diesel	$73/barrel
in Crude-Equivalent Price	$56/barrel
Naphtha	$30/barrel
Electricity	$58/MWh
Min. Pre-Tax Debt Service	1.67x
At 17% IRR	
FT Diesel	$67/barrel
in Crude-Equivalent Price	$52/barrel
Naphtha	$30/barrel
Electricity	$58/MWh
Min. Pre-Tax Debt Service	1.50x

Price results are based upon two different assumptions regarding the internal rates of return (IRR) that equity sponsors are likely to require for early commercial projects of this type: 17 percent and 19 percent. Trial analyses on other Reference Plants determined that sensitivities are similar for all plants considered in this study.

The analysis of the bituminous coal-based Reference Plant indicates that the price of FT diesel needs to be in the range of $73 per barrel, or $56 per barrel in crude-equivalent price (CEP), to achieve a target IRR of 19 percent. To achieve this pricing on a stable basis — which it must for the project to maintain an adequate debt service coverage ratio throughout the life of its debt financing, the analysis assumes that the project owner/operator places a long-term contract with a creditworthy fuel purchaser for a sufficient part of the plant's production to meet debt payments. Under assumptions of lower IRRs, specifically, 17 percent and 15 percent, the required price falls to $67 per barrel ($52 per barrel CEP) and $62 per barrel ($47 per barrel CEP), respectively. Importantly, debt service coverage declines with decreases in project IRR, making financing uncertainty a bigger issue at lower rates of return. In interviews, financial experts agreed that an IRR of 17–19 percent reflects financial market conditions and expectations for early commercial co-production projects.

Results of Sensitivity Testing

A variety of sensitivity tests on several input and other assumptions for this Reference Plant identified which elements drive significant changes in FT fuel price. Exhibit ES.3 presents a summary of the results of these sensitivity tests.

All the variables tested have a material effect in the pricing of FT fuel. The price of FT diesel is most sensitive to EPC cost, IRR, capital structure, plant size, construction time, and debt amortization period. The analysis further shows that the price of FT fuel is moderately sensitive to coal cost, naphtha price and output percentage, electricity price, and final availability. Although the separation (capture) of carbon dioxide is integral to plant operations (i.e., for efficient production of syngas and FT fuels), the addition of carbon dioxide compression increases the price of FT diesel by 5.6 percent. Revenue from the sale of captured carbon dioxide for EOR may pay for the cost of capture and compression, as well as decrease the cost of FT diesel by 4.2 percent, depending on the price obtained.

In general, the analysis of sensitivity testing results shows that changes to capital cost and capital structure have a greater effect on the price of FT fuel than do changes in variable costs (e.g., coal) or prices of outputs with lower value than FT fuels. Very large scaling benefits arise over the plant size range 10,000 barrels per day to 30,000 barrels per day, then taper off. Also, because coal prices vary significantly by type, the use of sub-bituminous coal may enhance plant prospects.

Exhibit ES.3: Summary of Sensitivity Testing Results for Bituminous Coal Reference Plant

Sensitivity Test	Input Value Change	Increase: Price of FT Diesel /bbl	Increase: Price in Crude-Equiv. /bbl	Decrease: Price of FT Diesel /bbl	Decrease: Price in Crude-Equiv. /bbl	Percentage Change from Reference Case
Base Case: FT Diesel Value = $72.83, Crude-Equivalent Price = $56.02						
EPC Cost	+/- 25%	$ 86.48	$ 66.52	$ 59.20	$ 45.54	+/- 18.7%
Coal Cost	+/- 33%	81.93	63.02	63.76	49.05	+/- 12.5%
Interest Rates	+/- 200 bps	77.25	59.42	68.83	52.95	+ 6.1% / -5.5%
Price of Electricity Sold	+/- 15%	70.80	54.46	74.88	57.60	-/+ 2.8%
Construction Time	+ 1year / - 6 months	82.28	63.29	67.12	51.63	+ 13.0% / -7.8%
Debt Amortization Period	+/- 5 years	69.10	53.15	79.80	61.38	-5.1% / 9.6%
Final Availability	+/- 5%	68.90	53.00	78.35	60.27	-5.4% / 7.6%
Reduced Naphtha Output	15% of output	-	-	69.20	53.23	-5.0%
Higher Naphtha Price	+ 100%	58.80	45.23	-	-	-19.3%
Capital Structure (Debt Percentage)	+/- 10%	66.6	51.23	80.66	62.05	-8.6% / 10.8%
Faster Ramp-up	75%, 85%, and 90%	-	-	70.23	54.02	-3.6%
Plant Size	10,000 bpd/ 60,000bpd	99.89	76.84	69.06	53.12	+ 37.2% / -5.2%
Use of CO_2 for EOR	$12/ton CO_2	-	-	$ 69.79	$ 53.68	-4.2%

Results of Carbon Sequestration Analysis for Reference Plants

Preliminary analysis suggests that, unless carbon dioxide from co-production plants is permanently sequestered, producing and consuming one gallon of FT fuel could emit up to twice as much carbon dioxide as one gallon of conventional crude-derived diesel or aviation fuel on a “well-to-wheels” basis.[6] However, since the capture of carbon dioxide produced during gasification and the FT process is integral to production in Reference Plants that produce FT fuels, these plants may provide an early opportunity for large-scale, cost-effective sequestration. In contrast, capturing carbon dioxide represents the largest cost associated with sequestration for coal combustion-based facilities. Additional costs associated with implementing sequestration for coal co-production

[6] “Greenhouse Gas Impacts of Expanded Renewable and Alternative Fuels Use” Environmental Protection Agency, Office of Transportation and Air Quality. EPA420-P-07-035. April 2007.

plants originate from compressing, transporting, storing, and monitoring[7] the carbon dioxide. These costs include:

- Carbon Dioxide Capture (CC): The cost of CC is integral to co-production processes because it optimizes plant cost and performance. Because the plants separate the carbon dioxide from the syngas and during upgrading of FT fuels they produce, CC is not included in the cost to sequester carbon dioxide;
- Compression: The capital cost of compressors is approximately $50–$58 million. Operating costs of compression are primarily associated with an increased parasitic load of approximately 53 MWe;
- Transportation: The capital cost of a pipeline that transfers compressed carbon dioxide to a storage site is approximately $62.5 million; annual operation and maintenance costs are approximately $1.6 million;
- Storage: Although the cost of storage varies widely, the analysis uses a cost of $4.78 per ton of sequestered carbon dioxide; and
- Measurement, monitoring, and verification: This cost amounts to approximately $0.3 per ton of sequestered carbon dioxide.

To explore this opportunity, the study evaluates the economic viability of incorporating sequestration capabilities in co-production plant operations. In performing the analysis of the impact on FT fuel price of adding carbon dioxide compression and sequestration to a bituminous coal-based Reference Plant with CC, these additional sequestration costs were incorporated into the Reference Plant, as well as into two similar Reference Plants that use sub-bituminous coal and lignite. This analysis determined the FT fuel price required to sustain sequestration for each type of Reference Plant.

Exhibit ES.4 provides the price of FT fuel needed to achieve 19 percent IRR for three different coal types and plant configurations.

Exhibit ES.4: FT Fuel Price for Different Coal Types and Plant Configurations

Type of Co-Production Plant (price in $/barrel)	Reference Plant Using Bituminous Coal		Reference Plant Using Sub-bituminous Coal		Reference Plant Using Lignite	
	Price of FT Fuel	Difference from Previous	Price of FT Fuel	Difference from Previous	Price of FT Fuel	Difference from Previous
Base Case	$ 72.83		$ 59.00		$ 76.00	
with CC&C	76.88	4.05	63.04	4.04	80.16	4.16
with Sequestration	82.83	5.95	68.73	5.69	86.35	6.19
with EOR	$ 73.07	$ (9.76)	$ 59.58	$ (9.15)	$ 76.00	$ (10.35)

7 The terms “monitor” and “monitoring” include “measurement, monitoring, and verification.”

As the exhibit illustrates, for all three plants, the base case price of FT fuel assumes the capture and release into the atmosphere of carbon dioxide produced in the gasification and FT processes. In carbon capture and compression ("with CC&C") scenarios, captured carbon dioxide is compressed for hand-off to a carbon dioxide pipeline at "plant gate." In scenarios "with sequestration," compressed carbon dioxide is transported, stored, and monitored at a suitable reservoir. Finally, the "with EOR" scenarios assume sale and use of the carbon dioxide for EOR with permanent sequestration at a price of $12 per ton.

The analysis shows that compression adds approximately $4 per barrel to the price of FT fuel from Reference Plants. The cost of transporting, storing, and monitoring the carbon dioxide adds about $5.69–$6.19 per barrel, depending on the amount of carbon dioxide produced by a plant and captured. Since the plant using sub-bituminous coal produces the least carbon dioxide, it incurs the lowest cost of sequestration. The benefit of EOR revenues appears to largely offset the cost of sequestration, assuming a ready long-term carbon dioxide off-taker willing to pay $12 per ton. Thus, early co-production plants are likely to be located relatively near to an EOR project, revenues from which will work like those from a long-term purchase agreement to further reduce FT fuel price.

The analysis reveals that the addition of carbon sequestration increases the price of FT fuel from a co-production plant using bituminous coal 14 percent to $83 per barrel. For plants using sub-bituminous coal and lignite, sequestration adds approximately 16 percent (to $68.73 per barrel) and 14 percent (to 86.35 per barrel), respectively, to the price of FT fuel.

Since the prices required to sustain sequestration operations put plants at a serious competitive disadvantage in the fuel market, either incentives or mandatory limits on carbon dioxide emissions would likely be needed for the capture and sequestration of carbon dioxide by early commercial co-production facilities. The results of this analysis inform discussion of the means for accelerating or encouraging sequestration by illuminating the relationships among key factors that impact the financial viability of co-production projects and by identifying, in the context of a set of transparent assumptions, the breakeven point for adding geological sequestration in the absence of a mandatory carbon dioxide limitation.

Summary of Reference Plant Analyses

Results of the Reference Plant analyses offer important insights into the necessary conditions for successful early commercial coal gasification with co-production projects. Key observations include:

- Information in the public domain regarding optimal configurations, project size, plant performance, and cost is limited and conflicting; available cost estimates for late 2005 are preliminary in nature and could vary by +/- 30 percent, and additional adjustment is needed due to a rapid increase in capital cost over the past two years. However, experts generally agree that a mid-size plant (30,000 bpd) will require a significant investment in the range of $3.3–$3.7 billion, depending on type of coal and use of CC&C. Ultimately, the cost of a co-production plant will be influenced significantly by its size. The analysis projects a 37 percent difference in FT fuel price between small plants (10,000 bpd) and mid-sized Reference Plants (30,000 bpd), reflecting a substantial scaling benefit.

- As indicated in Exhibit ES.4, the price of FT diesel produced in a Reference Plant that uses bituminous coal needs to be in the range of $73 per barrel, or $56 per barrel in crude-equivalent price (CEP), to meet investor requirements. The addition of compression increases the cost of FT fuel by about 5 percent, or about $4.00 per barrel ($3.08 per barrel CEP). (The further addition of sequestration will add about $6.00 per barrel [about $4.62 per barrel CEP]).
- Financing a co-production plant will remain a challenge for several reasons:
  - The oil market consistently has exhibited price volatility over the past 30 years, and investors continue to be concerned about the impact of oil price fluctuations, particularly decreases. This concern is reflected in the $40 per barrel floor price applied by credit rating agencies to new energy projects.[8]
  - The lack of standards and track records for fixed-price EPC contracts with performance guarantees and provisions for liquidated damages could impair the prospects of early commercial co-production projects, since bond holders may lack sufficient credit protection against downside risk; and
- Carbon dioxide storage costs and the price of carbon dioxide for EOR can materially impact plant economics. EOR with sequestration presents an additional opportunity to stimulate early commercial projects that sequester anthropogenic carbon dioxide, but the pricing of carbon dioxide for use in EOR projects is uncertain.

B. Alternative Plants and Sensitivity Testing

Results of the Analysis of Alternative Plants

This section summarizes the results of analyses of the financial prospects of co-production Alternative Plants that produce increased net power and reports the results of sensitivity testing on several key project inputs and outputs. The analyses are based on the mid-sized (~30,000 bpd) Reference Plant that uses bituminous coal and has an alternative configuration and higher capital costs associated with increasing power production. This alternative configuration (Alternative Plant) approximately doubles a plant's net electricity production compared to the bituminous coal-based Reference Plant.

8 "Industry Report Card: Diverging Natural Gas And Crude Oil Prices Result In A Mixed U.S. Oil And Gas Outlook" Table 1 on page 6. Standard & Poor's. September 11, 2007.

A number of costs and benefits arise from altering the Reference Plant configuration to increase net power production. The most notable incremental costs of the increased power configuration are those resulting from the requirement for an additional gasifier, greater coal handling capability, and a greater amount of coal. Other financial impacts of the Alternative Plant configuration include a revenue decrease from reducing the production of FT fuel and naphtha by approximately 2,500 barrels.

The price of FT fuel required to attain 19 percent IRR is comparable for the Reference Plant and the Alternative Plant; the price differs only by the small margin of 50 cents (CEP: 38 cents) per barrel. It therefore appears that the increased net power production of 333 MWh in the Alternative Plant roughly offsets, in economic terms, the plant's decreased FT fuel and naphtha production. More importantly, this greater percentage of energy production in the form of electricity, absent any sizable affects on FT fuel price, offers plant owners the opportunity to benefit from a more diverse set of outputs, which somewhat insulates them from price volatility in the oil markets.

Exhibit ES.5 provides a summary of these findings, which offer important insights into the prospects for early commercial co-production plants.

Exhibit ES.5: Summary of Analytical Results for the Alternative Plant

		Alternative Plant		
		Value: +	Value: -	
Summary of Analyses	Value Change	Price of FT Fuel (CEP) $/bbl	Price of FT Fuel (CEP) $/bbl	% Change in Price from Base Case
Base Case Fuel Price		**FT Diesel = $72.65, Crude-Equivalent = $55.85**		
Debt Coverage	1.1x	$49 ($38)		
Electricity Price	+ 25%	$66 ($51)		
Sensitivity Testing				
EPC Costs	+/- 25%	$90 ($69)	$56 ($43)	+ / - 23.7%
Coal Cost	+/- 33%	$83 ($64)	$62 ($48)	+ / - 14.7%
Reduced Naphtha Output	15% of output	-	$69 ($53)	- 5.1%
Interest Rates	+/- 25%	$78 ($60)	$68 ($52)	+7.3% / -6.6%
Final Availablity	+/- 5%	$68 ($52)	$79 ($61)	-6.6% / +9.2%
Construction Time	+1 year/ -6 months	$81 ($62)	$69 ($53)	+10.9% / -5.2%

Several important conclusions arise from the Alternative Plant analysis:

- Increasing net power production does not have a material effect on FT fuel price;
- Higher electricity prices reduce the FT fuel price from an Alternative Plant and can reduce credit concerns;
- The combination of increased power output and a long-term purchase agreement for power can enhance the credit quality of an Alternative Plant by providing

greater insulation from commodity price risk associated with the plant's FT fuel outputs;

- FT fuel price sensitivity for Alternative and Reference Plants is similar; and
- Used in a risk-informed manner, incentives could "close the gap" that jeopardizes construction and operation of early commercial Alternative Plants.

Results of Sensitivity Testing of Alternative Plants

FT fuel price sensitivity of Alternative Plants is similar to that of Reference Plants. The analysis makes it clear that the most significant risks to the economic viability of an Alternative Plant with sequestration occur due to market price risk associated with volatility in the price of crude oil-based products, high capital cost, integration risk, and the addition of sequestration.

Exhibit ES.6 summarizes a comparison of sensitivity testing results for the Alternative Plant with carbon capture and an Alternative Plant with sequestration.

Exhibit ES.6: Sensitivity Testing for Alternative Plants with CC and with Carbon Sequestration

Summary of Analyses	Value Change	Alternative Plant			Alternative Plant with Sequestration		
		Value: + Price of FT Fuel (CEP) $/bbl	Value: - Price of FT Fuel (CEP) $/bbl	% Change in Price from Base Case	Value: + Price of FT Fuel (CEP) $/bbl	Value: - Price of FT Fuel (CEP) $/bbl	% Change in Price from Base Case
Base Case		**FT Diesel = $72.65, CEP = $55.85**			**FT Diesel = $83.47, CEP = $64.21**		
Debt Coverage	1.1x	$49 ($38)			$59 ($45)		
Electricity Price	+ 25%	$66 ($51)			$77 ($60)		
Sensitivity Testing							
EPC Costs	+/- 25%	$90 ($69)	$56 ($43)	+ / - 23.7%	$102 ($78)	$66 ($51)	+ / - 21.7%
Coal Cost	+/- 33%	$83 ($64)	$62 ($48)	+ / - 14.7%	$94 ($72)	$73 ($56)	+ / - 12.8%
Reduced Naphtha Output	15% of output	-	$69 ($53)	- 5.1%	-	$79 ($60)	- 5.9%
Interest Rates	+/- 25%	$78 ($60)	$68 ($52)	+7.3% / -6.6%	$89 ($68)	$78 ($60)	+6.6% / -6.0%
Final Availablity	+/- 5%	$68 ($52)	$79 ($61)	-6.6% / +9.2%	$79 ($60)	$90 ($70)	-5.9% / +8.3%
Construction Time	+1 Year/ -6 months	$81 ($62)	$69 ($53)	+10.9% / -5.2%	$92 ($71)	$80 ($61)	+9.9% / -4.7%
CO_2 Storage Costs	+/- 50%				$86 ($66)	$81 ($63)	- / + 2.6%

The sensitivity testing of Alternative Plants with sequestration shows that variations in capital cost, construction time, construction cost overruns, plant availability, output prices, coal cost, and naphtha production all have material impacts on the price of FT fuel, while carbon dioxide storage costs do not. FT fuel price is not sensitive to changes in the cost of sequestration.

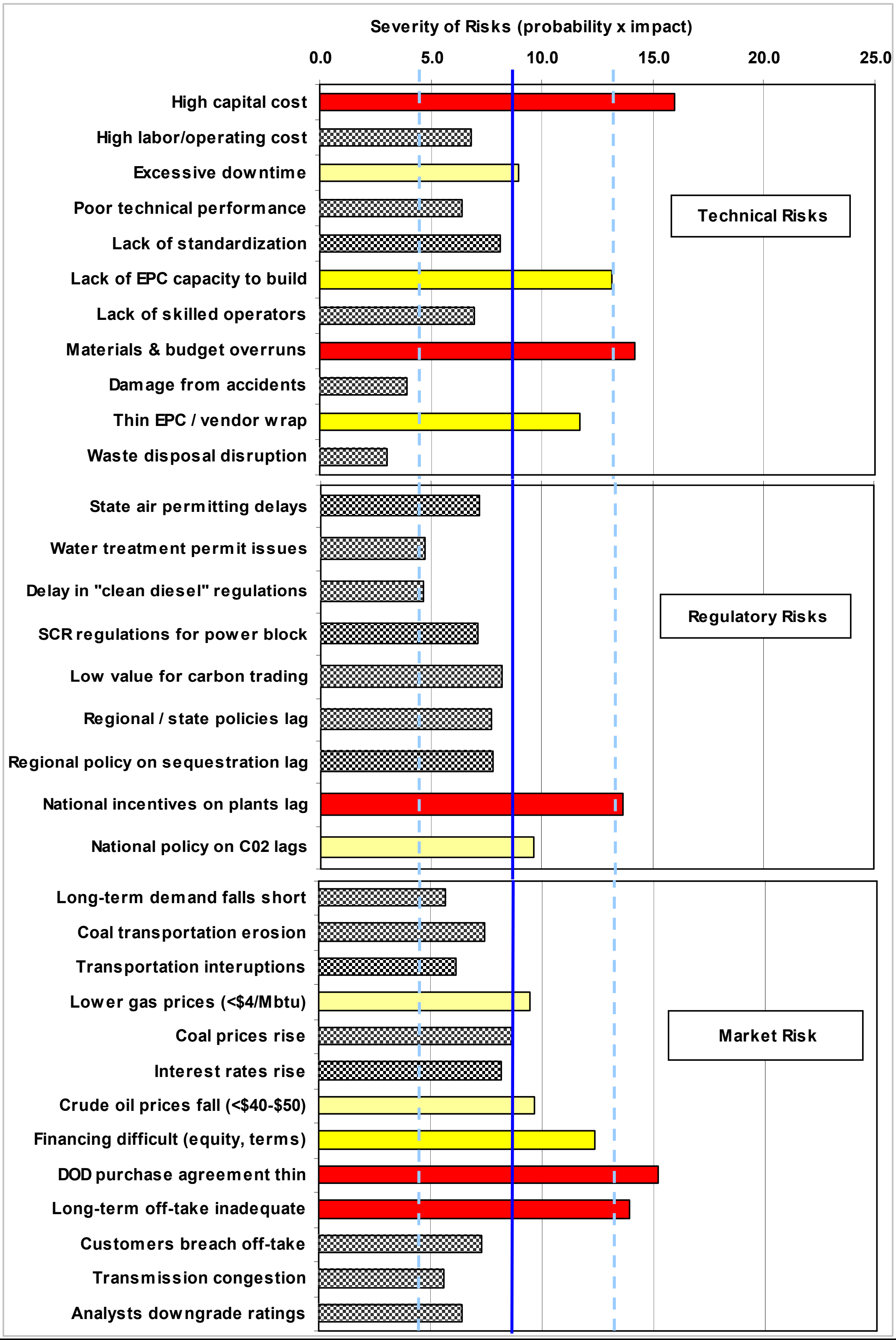
C. Business Risk Analysis

To evaluate the perspective of experts in all aspects of co-production projects about the business risks that affect the financeability of early commercial co-production plants, Scully Capital distributed a risk rating questionnaire to 50 industry experts and received 20 complete responses. Respondents did not identify any barriers that will prevent the construction and operation of co-production projects among the 33 risks in the query, but several risks rise to the level that project developers cannot address them alone or with the assistance of private risk-mitigation instruments.

Exhibit ES.7 provides a summary of the ratings compiled in the fall of 2006. As the exhibit shows, the risk-rating responses converge on several themes that are important to the development of project financings. In particular, high capital costs and off-take/purchase risk represent threshold areas of concern. Other highlighted risks include concerns about warrantees for facility technical performance and ability to obtain financing for early commercial projects:

- **High capital cost:** Respondents rate as their greatest concern the high fixed costs of a co-production facility. Concerns over high materials prices and potential budget overruns in a backlogged "engineer, procure, construct" (EPC) contractor market and a weakening dollar reinforce high capital cost as a threshold concern to respondents. The implication of this risk is that the products of a co-production facility may not be competitive in energy markets, which experience significant price fluctuations.
- **Revenue and off-take/purchase risk:** Respondents express serious concerns about the volatile nature of the commodity markets in which co-production plants will compete. The projection that FT fuels must be priced well above $50 per barrel to provide adequate financial returns makes purchase agreements, which can cushion price volatility, potentially very important. The possibility that DoD or other creditworthy government or private entities will be unable to undertake adequate purchase agreements could leave this risk unaddressed.
- **Warrantees for facility technical performance:** While the technologies employed in co-production facilities are well understood, the fact that a full-scale commercial co-production facility has not been built in the United States represents an area of significant concern, as reflected in the elevated risk rating for availability of EPC performance wraps. Technology performance risk typically is assigned to the project's EPC contractor. However, the lack of standardized designs for co-production facilities and the limited risk-bearing capacity of EPC firms to (1) absorb an undertaking of this magnitude and (2) wrap a facility's performance risk make this a key area of concern.
- **Financing risk:** Due primarily to these threshold risks, obtaining financing is a key area of concern. Financing projects is likely to be difficult unless national incentives are available to mitigate risks to early commercial projects, purchase agreements can be contracted, and carbon risk can be hedged.

Exhibit ES.7: Summary of Risk Ratings



The solid purple line shows the average rating (9.0 on a 25-point scale) in 20 questionnaire responses for 33 technical, policy and regulatory, and market risks. In general, the risks with low ratings also show low variability. To highlight the key concerns of respondents, red designates ratings of risks above the average by more than one standard deviation, while yellow identifies risks rated above average by less then a full standard deviation.

To supplement the risk ratings analysis, Scully Capital conducted an outreach effort to leaders involved in the development and financing of co-production facilities by interviewing senior executives, project developers, engineering firms, and financial institutions. Importantly, interviewees spoke on the condition that their comments would not be subject to specific attribution.

The combination of the risk ratings and interviews helps provide a clear picture about project risks and financial returns from the perspective of potential owner/operators of co-production projects, their business partners, and other key players. The results of other parts of this study suggest that coal gasification with co-production is technically feasible and, without incentives, economically marginal. The questionnaire and interview results confirm that perceived risks related to a facility's cost, technical efficacy, and market competitiveness rise to the level that they represent threshold barriers to early commercial projects of this type. Other significant conclusions from the interviews include:

- An off-take arrangement with a creditworthy counterparty, which establishes a dependable market for a facility's outputs by offsetting the effect of price volatility in energy markets, is essential to alleviating concerns about investment risk. Numerous structuring options exist for off-take agreements;
- High capital costs and output commodity risk, which rank as the highest rated risks, will limit financial feasibility;
- The likely lack of EPC wraps with performance guarantees on co-production plants is a key obstacle to arranging financing for projects. The need to address technical uncertainty by increasing reserves and contingencies reinforces capital cost concerns;
- Plants may be built using a project finance structure, but interviewees cite the need to address an apparent lack of EPC wraps and the need for a long-term, creditworthy off-taker as keys to completing non-recourse financings:
- Internal rates of return for early commercial plants are likely to be in the 17–19 percent range, but they could rise in the absence of a high-quality off-take agreement; and
- Off-take arrangements will be necessary for the first few plants because they can improve credit quality more than other incentives, particularly in combination with loan guarantees, and additional government incentives are critical.

D. Analysis of Financial Incentives

Without implying advocacy for any particular incentives, this section reports the results of an analysis of the impact of potential government incentives on the economics and financial feasibility of a Reference Plant. It also comments on the applicability of various instruments to the management of individual important project risks and the cost to the government of providing specific incentives. The analysis of incentives concludes that a sustained national policy commitment with a tolerance for short term disappointments is likely to be needed to address the level of financial exposure associated with projects of this size, cost, and complexity.

Incentives for Reference Plants

The effect of government incentives analyzed ranges from promoting capital investment (e.g., by decreasing the financing cost of a plant, by facilitating financing) to promoting production (e.g., with excise tax credits). In analyzing the Reference Plant, the study assumes that a long-term purchase agreement (PA) with a creditworthy counterparty is a part of the core financial structure of a project. PAs can assure the cash flows needed to satisfy debt servicing requirements and serve to address concerns of financing sources. However, since the needed price of fuel sales is higher than the long-term price expectation for fuels, incentives can significantly reduce market and other risks (or, conversely, increase the competitiveness of a plant's products) by decreasing the price of FT fuel within the constraint of a target IRR (19 percent in the analysis). These incentives include loan guarantees, excise tax credits, investment tax credits (ITCs), and cost-sharing. Other incentives examined in the study have a smaller impact on the price of FT fuel and co-products.

In addition to examining the benefits of each incentive to project sponsors, Scully Capital examined their potential cost to Federal and state governments, concluding that the budgetary impact of an incentive is an important part of the determination of whether an incentive is cost-effective, particularly in relation to its policy objective.

Exhibit ES.8 lists the Federal incentives analyzed, summarizes the impact each incentive, operating separately and in combination, could have on the price of FT fuel, and indicates the budget impact of utilizing each incentive. A number of significant observations rise from the analysis of purchase agreements and incentives:

- Purchase agreements are necessary to manage price volatility in crude oil and natural gas markets. PAs also can be provided by a creditworthy government agency or private entity. However, under Federal budgeting guidelines, long-term PAs tend to have a large budgetary impact. Though government PAs are included in the financial structure of the Reference Plants, PAs alone may not be sufficient to ensure construction and operation of a co-production plant. PAs also can be structured more flexibly by a private entity or a government agency as an incentive to enhance the prospects of a plant.

- Loan guarantees can improve the prospect of obtaining financing for a project by improving the creditworthiness of a project and reducing interest rates. The effectiveness of a loan guarantee depends on its structure. Loan guarantees have a lower budgetary impact than other incentives and show, for projects constructed using a project finance structure, greater benefit than tax incentives.

Exhibit ES.8: Summary of Federal Incentives Analyzed

Type of Incentive	FT Diesel Price per Barrel	Crude-Equivalent Price per Barrel	Percentage Change from Reference Case	Budget Impact ($ millions)	Total Cost ($ millions)
Loan Guarantees					
100% of Debt Guaranteed					
Gov't Pays Credit Subsidy	$ 51	$ 39	30%	$ 188	$ 188
Self-Pay Credit Subsidy	60	46	18%	-	-
80% of Debt Guaranteed					
Self-Pay Credit Subsidy	$ 63	$ 48	14%	$ -	$ -
Tax Incentives					
Investment Tax Credit					
20%	$ 67	$ 52	8%	$ 129	$ 109
20% + Expensing	62	48	15%	194	87
Excise Tax Credit					
5 Years Production					
10 cent	70	54	4%	150	150
25 cent	65	50	11%	375	375
50 cent	57	44	22%	751	751
10 Years of Production					
10 cent	68	52	6%	318	318
25 cent	61	47	16%	795	795
50 cent	54	42	26%	1,591	1,591
50% Expensing of FT Equip.	72	55	1%	20	-
Tax Exempt Debt	$ 71	$ 55	3%	$ 325	$ 643
Other Incentives					
Purchase Agreement (PA)					
OMB A-11 Method	$ 73	$ 56	0%	$ 6,957	$ 6,957
Total Cash Outlay	73	56	0%	10,364	10,364
Grants					
$200 million grant					
Without Repayment	69	53	6%	200	200
With Repayment	68	52	7%	200	200
$1.3 billion grant (50-50 Cost Share)					
Without Repayment	46	36	36%	1,306	1,306
With Repayment	49	38	33%	1,306	1,306
Combination Cases					
Combination Case 1	$ 43	$ 33	41%	$ 781	$ 781
Combination Case 2	$ 51	$ 39	30%	$ 383	$ 383

- Benefits of tax incentives depend on the tax loss absorption capacity of sponsors and the scale and timing of benefits. ITCs decrease the effective cost of

equipment and, therefore, the cost to produce. Production-based tax credits (PTC) reduce the marginal revenue required to produce FT fuels competitively. All tax credits evaluated are expensive to the government.

- A 50-50 cost-share grant significantly improves the financial prospects of a first-of-a-kind co-production plant but is expensive to the government. Relatively small cost-share grants do not help the financial prospects of co-production plants significantly, although a small cost-share grant early in the development of a project can be significant. Interest-free payback of such grants does not materially impact the economics of the incentive.
- State incentives also can help promote investment by improving the business climate, speeding development of a project, and (in states which regulate the electricity and natural gas infrastructure) assuring product sales. In particular, states' ability to assure returns via action by a public utility commission or via a purchase agreement is a powerful incentive that stabilizes cash flows for a significant portion of a plant's production.
- Combining incentives offers the potential to cost-effectively target incentives to specific project risks and enhance the project's long-term competitiveness. If the sponsors of early commercial projects confront multiple risk factors that negatively affect the prospects of obtaining financing, a combination of incentives may be needed to allow their projects to go forward. The analysis shows that the combination of a small state grant early in the life of a project, a loan guarantee, and an excise tax credit, the elements of the two combination cases, may be the most cost-effective way for government agencies to risk-share with the sponsors of a Reference Plant. Combination Case 2, which provides less of these incentives than Combination Case 1, targets the $40 per barrel crude-equivalent floor price applied by credit rating agencies to new energy projects. (Combination Case 1 targets the lower $33 per barrel floor price applied by credit rating agencies until some time in 2006.)

Incentives for Plants with Sequestration

Further analysis explored the type and level of incentive required to encourage e plant owners to sequester carbon dioxide produced in co-production projects. Modeling showed that a tax credit per ton of carbon dioxide sequestered has advantages over incentives that encourage investment in sequestration equipment (e.g., ITCs, loan guarantees) and may be the optimal incentive for encouraging sequestration. The modeling also observed the level of tax credit per ton of carbon dioxide sequestered required for a co-production plant to compete with crude-based fuels. A tax credit of this type and level would allow a plant sequestering carbon dioxide it produces to sustain operations while remaining competitive.

Exhibit ES.8 provides an overview of key findings related to the cost of carbon dioxide compression and sequestration, the benefits of EOR with sequestration, and the tax credit level required to offset the cost of sequestration for all three Reference Plants.

Exhibit ES.8: Summary of Costs of Sequestration and Tax Credit Levels

Type of Co-Production Plant (price in $/barrel)	Reference Plant Using Bituminous Coal		Reference Plant Using Sub-bituminous Coal		Reference Plant Using Lignite	
	Price of FT Fuel	CEP	Price of FT Fuel	CEP	Price of FT Fuel	CEP
Base Case	$ 72.83	$ 56.02	$ 59.00	$ 45.38	$ 76.00	$ 58.46
with CC&C	76.88	59.14	63.04	48.49	80.16	61.66
with Sequestration	82.83	63.72	68.73	52.87	86.35	66.42
with EOR	$ 73.07	$ 56.21	$ 59.58	$ 45.83	$ 76.00	$ 58.46
Tax Credit to Offset Costs of Sequestration						
Tax Credit ($/ton)	$10.90 /ton		$11.30 /ton		$10.63 /ton	
Budgetary Impact ($ millions)	$672		$643		$694	
Total Cost ($ millions)	$672		$643		$694	

This exhibit shows that sequestration adversely affects the competitiveness of FT fuel produced in a plant unless the carbon dioxide is sold. It shows that, without factoring in the effect of EOR on plant revenues, a tax credit of $10.63–$11.30 per ton would be needed for this purpose, depending on the type of coal used in a plant and not taking into account the potentially significant benefits and costs associated with a particular site. Industry sources indicate that carbon dioxide sells today for EOR use at prices ranging from $5–$12 per ton delivered, so revenues from sales of carbon dioxide could be material.

The effectiveness of a sequestration-based incentive will depend foremost on the cost of sequestration and on the effect of the incentive in managing risk. A tax credit priced at the cost levels to sequester carbon dioxide indicated in Exhibit ES.8 could offset sequestration costs for co-production plants that produce FT fuels, depending on the type of plant and on location-specific variables. On the other hand, investment tax credits and loan guarantees are examples of incentives that can stimulate investment in sequestration infrastructure without actually encouraging sequestration operations.

Thus, certain incentives can be particularly effective in helping industry and other stakeholders gain experience in the construction and operation of early commercial co-production projects that sequester the carbon dioxide they produce. If the tax credit for tons of carbon sequestered spreads the financial incentive over a sufficient time, it may sustain sequestration activity long enough for this crucial learning to occur. In the absence of statutory requirements for sequestration, however, plant operators may be unlikely to sequester carbon dioxide after the expiration of a tax credit for sequestration.[9]

[9] "Unlikely" because plant owners may decide to sequester for other reasons. For example, the Air Force, which is seeking supplies of FT fuel from such alternative sources as co-production, has stated that it will purchase fuel on a long-term basis only if the plant producing it sequesters the carbon dioxide it produces, absent any greenhouse gas emission regulations.

Carbon Capture Performance Assumptions

Although the study utilizes all of the technical assumptions from Mitretek in the Reference Plant analysis, it uses one significant assumption that is outside the Mitretek study. Specifically, without making any changes in the Mitretek engineering design and cost assumptions for the sequestration case, this analysis utilizes a more conservative estimate for carbon capture performance. Based on discussions with industry, Mitretek assumed that plant equipment would capture 95 percent of the carbon dioxide at two points (after the coal gasification step and after the FT process). In addition to Mitretek's work, various studies (IPCC Special Report on Carbon Dioxide Capture and Storage, MIT Future of Coal Report) have indicated that higher capture percentages are attainable — in the range of 90–95 percent.

The financial analysis in this study assumes that the carbon capture equipment would operate 90 percent of the time and that it would capture 80 percent of the carbon dioxide that Mitretek calculated would be captured, resulting in an overall carbon capture rate in the low-70 percent range. The numbers presented here thus rely on a more conservative figure than Mitretek.

The largest impact of a higher capture percentage would appear in the cost of the sequestration incentive, which would rise by approximately 25 percent due to the larger quantity of carbon dioxide being sequestered and earning the tax credit. Elsewhere in the sequestration analysis, other carbon sequestration-related costs would increase, with the effect that, for example, FT fuel prices would increase by 1–2 percent. No changes would result in the Reference Plant analysis.

I. INTRODUCTION

The Energy Policy Act of 2005 (EPAct 2005), the National Energy Policy, and the Advanced Energy Initiative call for greater use of domestic resources to improve the energy security of the United States. Price increases and volatility in international and U.S. crude oil and natural gas markets, along with increasing demand for energy in emerging economies, highlight the value of using lower priced and relatively plentiful domestic options to improve U.S. energy security. Foremost among available options is increased use of coal, the country's largest fossil fuel reserve with more than 250 years of supply at current usage rates.

At the same time, a discussion of increased coal use must take into account attendant environmental impacts, including increased emissions of carbon dioxide, the primary greenhouse gas. The gasification of coal, the subject of this set of analyses, offers the prospect of substantially reducing the overall environmental footprint associated with coal use compared to conventional technologies for generating electricity.[1] The gasification of coal is particularly amenable to carbon dioxide capture, and co-production projects also separate carbon dioxide after the conversion of syngas to FT fuels, making the cost of subsequent compression, transport, and injection of the carbon dioxide lower compared with coal combustion plants and most other large projects that use fossil energy.

Coal gasification converts coal into "syngas," a gas rich in carbon monoxide and hydrogen; carbon dioxide, sulfur, mercury, slag, and other by-products of gasification are amenable to capture, collection, and reuse (or, in the case of carbon dioxide, long-term sequestration), and nitrogen oxides are produced only at low levels. Separated carbon dioxide, once compressed and transported, can be stored permanently in underground geologic formations, used to stimulate methane recovery from coal beds that are inaccessible to economic coal extraction, or used for enhancing recovery of hydrocarbons from depleted oil fields; enhanced oil recovery, or EOR, can be conducted with or without permanent sequestration of the carbon dioxide.

Coal-derived syngas can be used in different ways, including powering a combined cycle gas turbine to produce electricity and/or serving as a feedstock for a range of chemical processes. Through the Fischer-Tropsch (FT) process, syngas can be converted into a wax which is then refined to produce FT fuels for transportation, such as FT diesel or FT jet fuel, plus naphtha. If a substantial portion (at least 75 percent to roughly 90 percent) of the carbon dioxide produced in the gasification and fuel conversion processes is permanently sequestered, the lifecycle carbon emissions of FT

[1] "An Environmental Assessment of IGCC Power Systems" Jay A. Ratafia-Brown, Lynn M. Manfredo, Jeff W. Hoffmann, Massood Ramezan (Science Applications International Corporation) and Gary J. Stiegel (U.S. DOE/National Energy Technology Laboratory) Presented at the Nineteenth Annual Pittsburgh Coal Conference, September 23–27, 2002.

fuels can be lowered to approximately the same levels as those from conventional petroleum-based fuels.[2] Although FT fuels can be produced from natural gas (gas-to-liquids or GTL), this report focuses on coal because of the large domestic supply and low cost per BTU.

The gasification of coal and other domestic energy sources, including biomass, to produce electricity, transportation fuels, chemicals, fertilizer, pipeline-quality synthetic gas, and other products can be broadly categorized as "Coal Gasification with Co-Production" (hereinafter referred to as co-production and industrial gasification). Co-production is important to several U.S. industries, such as nitrogen fertilizer, chemicals, glass, cement, and iron and steel, which rely on natural gas as an energy source and/or feedstock. The business risks, economics, and financing bottlenecks of constructing and operating co-production plants — particularly those that make transportation fuels, electricity, and naphtha — are the subjects of this project. The study team had hoped to analyze co-production plants that make a wider slate of products, but engineering design and cost data for other product slates are not available.

In March of 2006, the Department of Energy's (DOE) Office of Policy and International Affairs, the Department of Defense (DOD), and several industry associations teamed to sponsor this multi-phase and multi-report analysis by Scully Capital Services, Inc. (Scully Capital): "The Business Case for Coal Gasification with Co-Production." Industry sponsors include the Electric Power Research Institute (EPRI), American Chemistry Council (ACC), Gasification Technologies Council (GTC), The Fertilizer Institute (TFI), and the American Iron and Steel Institute (AISI). The goal of the analysis is to enhance readers' understanding of the business risks, economics, and financing challenges involved with co-production plants, with and without carbon sequestration, and of the applicability and cost of a range of incentives that governments, particularly, could apply to early commercial co-production facilities. David Berg of DOE's Office of Policy and International Affairs provided oversight and guidance to the project and an Integrated Project Team (IPT) that provided input and reviewed work products; the IPT was comprised of the sponsors of the project.

The Environmental Protection Agency provided sponsorship for one portion of the study, Task V.B., in order to broaden the scope of the study to include analysis of co-production facilities with carbon dioxide sequestration.

A. Overview of Project Elements

This report presents the results of this multi-phase and multi-report project. **Tasks I and II**, principally sponsored by DOE and DoD, respectively, analyzed the technical and financial assumptions of reference bituminous coal and lignite co-production plants

[2] Unpublished paper. Department of Energy. National Energy Technology Laboratory (NETL). August 2007. Lifecycle carbon emissions may be at least five percent less than those from conventional petroleum-based fuels depending on the type of production process used in the plant, the plant's source of electricity, and the type of oil used in the comparison.

(Reference Plants), determined the price of outputs, and performed sensitivity tests on key input variables.[3, 4] These tasks also provide general observations on the industry and potential challenges in financing co-production plants. **Task III**, principally sponsored by EPRI, outlines the technical requirements for increasing the electricity output of the bituminous coal Reference Plant, both with and without sequestration, and examines the financial impacts that these two configurations would have on FT fuel price.[5] It also provides sensitivities of the two alternative plant configurations to increased electricity prices and examines the degree of plant resilience to downturns in FT fuel prices. **Task IV**, principally sponsored by ACC, GTC, TFI, and AISI, determines which business risks most affect the financeability of co-production Reference Plants and evaluates the perspectives of experts in all aspects of co-production projects about these business risks.[6] **Task V.A.**, principally sponsored by EPRI, provides the results of analyses of the differing effects of a range of incentives on the economics and financeability of Reference Plants.[7] **Task V.B.**, principally sponsored by EPA, provides additional context by examining the financial impacts of sequestering the carbon dioxide produced in Reference Plants.[8] The Task V.B. analysis also provides results for a third Reference Plant that uses sub-bituminous coal.

B. "Reference Plant" Overview

Exhibit 1 provides an overview of the configuration of the bituminous coal co-production Reference Plant and price results for primary plant outputs. Price results derive from two different assumptions about the internal rates of return (IRR) that equity sponsors are likely to require for early commercial projects of this type. These Reference Plant data, along with data on the plant that uses sub-bituminous coal, form the basis for analyses throughout the report.

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[3] "The Business Case for Coal Gasification with Co-Production: Reference Plant Final Report (Tasks 1 and II)". David Berg (Department of Energy) and Brian Oakley, Sameer Parikh, and Andy Paterson (Scully Capital Services, Inc.), Scully Capital Services, Inc., October 2006.

[4] The specific configuration examined encompasses co-production facilities that produce diesel fuel, one type of FT fuel.

[5] "The Business Case for Coal Gasification with Co-Production: "Sensitivity Analyses for Alternative Plant Configurations and Product Mixes". Brian Oakley and Sameer Parikh (Scully Capital Services, Inc.) and David Berg (Department of Energy), Scully Capital Services, Inc., September 2007.

[6] "The Business Case for Coal Gasification with Co-Production: Assessment of Business Risks and Financing Challenges". David Berg (Department of Energy) and Brian Oakley, Sameer Parikh, and Andy Paterson (Scully Capital Services, Inc.), Scully Capital Services, Inc., October 2007.

[7] "The Business Case for Coal Gasification with Co-Production: Impact of Financial Incentives Draft Final Report (Task V.A.)". David Berg (Department of Energy) and Brian Oakley, Sameer Parikh, and Andy Paterson (Scully Capital Services, Inc.), Scully Capital Services, Inc., April 2007.

[8] "The Business Case for Coal Gasification with Co-Production: Analysis of incentives for Gaining the potential Carbon Benefits of Co-Production" David Berg (Department of Energy) and Brian Oakley, Sameer Parikh, and Andy Paterson (Scully Capital Services, Inc.), Scully Capital Services, Inc., October 2007.

Technical assumptions used in this study are derived from the American Energy Security Study sponsored by Southern States Energy Board (SSEB).[9] The study relies on a technical analysis conducted by Mitretek (now Noblis). Importantly, these cost estimates were preliminary in nature and could vary by +/- 30 percent.[10] In addition, site-specific characteristics that could increase and decrease plant cost are not incorporated into the analysis. Therefore, it is important to consider the numbers presented in this report to be preliminary ranges that could be refined by the specific characteristics of a project and detailed project-specific engineering.

Exhibit 1: Configuration and Results in Brief for Bituminous Coal Co-Production Reference Plant

Input Characteristics	
Tons of Coal Per Day	17,987
BTU Value of Bituminous Coal	11,800
Price of Coal Delivered	$36 / Short Ton
Output Characteristics at Capacity	
FT Liquids (bpd)	
FT Diesel	24,359
Naphtha	11,398
Total: Diesel-Equivalent FT	32,502
Electricity Production	
Gross (MWe)	725
Net (MWe)	257
Net (MWe) with Carbon Capture and Compression	205
Output Pricing	
At 19% IRR	
FT Diesel	$73/barrel
in Crude-Equivalent Price	$56/barrel
Naphtha	$30/barrel
Electricity	$58/MWh
Min. Pre-Tax Debt Service	1.67x
At 17% IRR	
FT Diesel	$67/barrel
in Crude-Equivalent Price	$52/barrel
Naphtha	$30/barrel
Electricity	$58/MWh
Min. Pre-Tax Debt Service	1.50x

The Reference Plant analysis utilizes a non-recourse project financing structure. Under this type of financing structure, a project "stands on its own" and its cash flows provide the underpinnings of creditworthiness. Conversations with developers and financiers indicated that this type of structure would likely be utilized for the first few plants. Importantly, this type of structure insulates project sponsors from the full risk of the

9 "American Energy Security – Building a Bridge to Energy Independence and to a Sustainable Energy Future". The Southern States Energy Board. July 2006. "SSEB Study" (www.sseb.org)

10 ibid. Appendix D. Page 16.

project, allowing risks to be shared by several participants in the project. The reference bituminous coal plant serves as the “Reference Plant” in this report.

The bituminous coal Reference Plant analysis indicates that the price of FT diesel needs to be in the range of $73 per barrel, or $56 per barrel in crude-equivalent price (CEP), to achieve a target IRR of 19 percent. To achieve this pricing on a stable basis — which it must in order for the project to maintain an adequate debt service coverage ratio throughout the life of its debt financing, the analysis assumes that the project owner/operator places a long-term contract with a creditworthy fuel purchaser for a sufficient part of the plant’s production to meet debt payments. Under assumptions of lower internal rates of return (IRR) — specifically, 17 percent and 15 percent — the required price falls to $67 per barrel ($52 per barrel CEP) and $62 per barrel ($47 per barrel CEP), respectively. Importantly, debt service coverage declines with decreases in project IRR, making financing uncertainty a bigger issue at lower rates of return. In interviews, financial experts agreed that an IRR of 17–19 percent reflects financial market conditions and expectations for early commercial co-production projects.

Preliminary lifecycle analyses (or “well-to-wheels” studies) performed elsewhere suggest that, unless the carbon dioxide from co-production plants is permanently sequestered (whether in conjunction with EOR operations or not), the carbon dioxide emitted by producing and consuming one gallon of FT transportation fuel could be as much as twice that from conventional crude-derived diesel.[11] This report discusses the potential to reduce carbon emissions from these levels in the Chapter 7 discussion of Task V.B. results. One method of mitigating carbon emissions from a large plant is to sequester them. Sequestration, more generally referred to as “carbon capture and storage” (CCS), includes separating, compressing, and transporting the carbon dioxide to an appropriate geologic formation, where it injected and stored permanently underground. Appropriate geologic formations include deep saline reservoirs, depleted or producing oil and gas fields, and unminable coal seams. Companies in the carbon sequestration business would characterize and select these reservoirs based on their ability to retain carbon dioxide for long periods of time and then monitor and validate their performance.

As mentioned above, compressed carbon dioxide streams can be used to enhance hydrocarbon recovery from (depleted) oil reserves. EOR can be conducted in conjunction with permanent storage if an EOR operator chooses to do so, but not every EOR operation will necessarily sequester its carbon permanently. For purposes of this report, EOR operators are assumed to sequester carbon dioxide permanently.

[11] ”Greenhouse Gas Impacts of Expanded Renewable and Alternative Fuels Use” Environmental Protection Agency, Office of Transportation and Air Quality. EPA420-F-07-035. April 2007. Clayton, Mark. “Coal in cars: great fuel or climate foe” Christian Science Monitor. March 2, 2007.

Capturing the carbon dioxide is typically projected to be the largest cost component in the capture and sequestration process in coal-based facilities.[12] In two major processes within co-production plants — coal gasification and the production of FT fuels, however, the capture of carbon dioxide is an inherent, non-incremental step in the production of high-quality syngas and FT fuels. Thus, the marginal cost of sequestering the carbon dioxide in co-production projects, including those that produce FT fuels, is the cost to compress, transport, store, and monitor it. As a result, a coal co-production plant that produces FT fuel may provide one of the early opportunities for large-scale, cost-effective commercial geological sequestration. Large-scale commercial sequestration will involve overcoming a number of technological, integration, regulatory, legal, and financial hurdles; most of these issues are outside the scope of this analysis and are discussed elsewhere in depth. Also, the capacity for geological sequestration is limited in some parts of the United States (e.g., New England), and the cost of sequestration will vary from site to site, so other anthropogenic sources of carbon dioxide will compete to utilize this capacity.[13]

C. Approach and Objectives of the Study

As noted earlier, this study was conducted in multiple parts with separate deliverables for each of several sponsors. This section provides a detailed overview of each study task.

Overview of Tasks I and II.

Tasks I and II develop a financial perspective about two mid-sized co-production "Reference Plants" that utilize, respectively, bituminous coal and lignite; the Reference Plants are optimized for transportation fuel production. All of the plants separate carbon dioxide from other outputs, and the plants are modeled with and without carbon capture and compression to determine the impact of compression on the cost of fuel. The two plants have an appropriate financing structure. The effects of the input assumptions are analyzed to determine the sensitivity of the financial results to key variables.

Scully Capital collaborated with the Southern States Energy Board (SSEB) and its sub-contractor, Mitretek, to obtain the engineering design and technical details of two Reference Plants which SSEB and Mitretek had developed. The specifications of the Reference Plants address capital cost, location, schedule, sizing, feedstocks, and outputs, including gasification, electricity, and transportation fuels. Mitretek developed rough cost estimates for these "generic" gasification with co-production plant configurations, which experts consider as close to technologically, operationally, and

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12 Intergovernmental Panel on Climate Change (IPCC) Working Group III. "IPCC Special Report on Carbon Dioxide Capture and Storage – Summary for Policymakers" Page 10. September 2005.

13 "On the Potential Large-Scale Commercial Deployment of Carbon Dioxide Capture and Storage Technologies: Findings from Phase 2 of the Global Energy Technology Strategy Project" James J. Dooley, Joint Global Change Research Institute, Pacific Northwest National Laboratory (PNNL) Presentation to the EPA's Clean Air Act Advisory Committee's Advanced Coal Work Group. February 8, 2007. See particularly slide 10 of 22. http://www.epa.gov/air/caaac/coaltech/2007_02_dooley.pdf

economically feasible as possible. Scully Capital used its project finance and corporate experience to develop an appropriate financing structure for the Reference Plants.

Modeling of the Reference Plants yielded a price for FT fuel for each plant. Sensitivity testing on the main input assumptions provided greater understanding of the volatility of the price of FT fuel to key input assumptions, assuming internal rates of return remain constant.

To accomplish the objectives of Tasks I and II, Scully Capital conducted the following eight sub-tasks:

- **Sub-task 1 – Historical Studies of Co-Production Plants:** Scully Capital performed research on available studies to determine the extent of public knowledge available in the field.
- **Sub-task 2 – Financial Model:** Scully Capital updated a project finance model to account for the numerous possible inputs and outputs in a co-production plant.
- **Sub-task 3 – Parameters of Reference Plant:** Scully Capital performed research on the inputs and outputs of each co-production plant to determine which are the most critical. As part of this effort, Scully Capital participated in roundtable discussions of Reference Plant assumptions with the IPT and key experts to validate the specifications. Scully Capital identified the parameters based on options that would lead to a Reference Plant with the lowest priced transportation fuel.
- **Sub-task 4 – Industry Communications:** Scully Capital met with industry participants to understand the critical issues surrounding the industry, as well as to confirm assumptions used in the study.
- **Sub-task 5 – Reference Plants:** Through collaboration with the Southern States Energy Board (SSEB) and Mitretek, which were responsible for the engineering design of the Reference Plants, Scully Capital obtained two technical Reference Plants. This collaboration yielded the specifications of two Reference Plants for co-production projects that address capital cost, location, schedule, sizing, feedstocks, and outputs, including gasification, electricity, and transportation fuels. The reference facilities provide rough cost estimates for a "generic" gasification with co-production plant configuration that experts consider as close to technologically, operationally, and economically feasible as possible. Scully Capital used its project finance and corporate experience to develop an appropriate financing structure for the Reference Plants.
- **Sub-task 6 – Findings on Reference Plants:** Based on the technical and financial assumptions, Scully Capital modeled the Reference Plants to obtain, for each plant, a price for FT fuel.

- **Sub-task 7 – Sensitivity Tests on Inputs:** Based on input from the IPT, Scully Capital performed sensitivity testing on the main input assumptions to understand the volatility of the price of FT fuel to key input assumptions.
- **Sub-task 8 – Summary and Recommendations:** Scully Capital developed conclusions and recommendations based on Reference Plant findings and the results of sensitivity testing.

Overview of Task III.
The Reference Plants examined in Tasks I and II were configured to maximize the production of FT fuels and be at least self-sufficient in electric power. Task III examines the economics of three alternative co-production plants (bituminous and sub-bituminous coal, and lignite), with and without carbon dioxide sequestration, that produce more power at the expense of FT fuel production. Task III outlines the technical requirements for increasing the electricity output of these plants. It also determines sensitivities of the two alternative plant configurations (with and without sequestration) to the effects of increasing electricity prices and examines the degree of plant resilience to downturns in FT fuel prices. Task III further assesses the impact of rising electricity prices and determines plant sensitivity to selected financing risks. It then examines the effects of these variations on the price of FT fuel price required for the plant to attain a 19 percent internal rate of return (IRR).

Engineering designs and cost projections for only one alternative configuration were available: a plant that produces more electric power at the expense of FT fuel production. Other configurations — such as for plants optimized to produce fertilizer or chemical feedstocks — were not available.

The Task III evaluation of the high-power configuration enhances our understanding of the prospects for co-production facilities in several ways. It illustrates the degree to which the production of greater amounts of electricity may introduce more stability into a project's revenue profile and, in turn, enhance creditworthiness. Methods of enhancing revenue stability are important because crude oil and natural gas markets experience price volatility. Also, the high-power configuration may lead to less commodity price risk exposure, overall, for the facility's outputs, potentially offsetting the additional technical risks associated with integrating increased power production.

To accomplish the objectives of Task III, Scully Capital conducted the following five sub-tasks:

- **Sub-task 1 – Determine Technical Assumptions:** Scully Capital consulted EPRI staff and various publications regarding the appropriate assumptions to make for bituminous coal-based plants with double the net power output of the Reference Plant, both with and without sequestration.
- **Sub-task 2 – Develop Base Cases for Alternative Plant Configurations:** Scully Capital incorporated the appropriate technical assumptions and the

financial assumptions consistent with each Reference Plant in order to develop base cases for the plants with increased net power output, with and without sequestration (Alternative Plant with Increased Net Power and Sequestration" and "Alternative Plant with Increased Net Power," respectively).

- **Sub-task 3 – Determine Economic and Financial Impacts of Alternative Configurations:** Scully Capital analyzed the two alternative plants to determine how increased net power output affects the cost of FT fuel.
- **Sub-task 4 – Analyze Sensitivities:** Scully Capital applied a number of sensitivity tests to each of the alternative plants and analyzed modeling results for their effects on the outputs generated by the model, particularly FT fuel price.
- **Sub-task 5 – Summary and Recommendations:** Scully Capital developed conclusions and recommendations based on the results of the analysis.

Overview of Task IV.

Task IV provides a financial and market perspective of the risks that may impact a co-production project's financial returns. To examine potential risks, the study team developed and disseminated a questionnaire to explore the significance of potential risks (technical, policy and regulatory, and market) associated with early commercial coal co-production facilities producing power, fuels, and other products. Industry experts drawn from the entire transaction train involved in developing co-production facilities were invited to respond. The responses were reviewed, compiled, and analyzed within the major risk categories and overall. Key agents involved in the process of developing and financing co-production facilities were then interviewed to explore the validity of findings from both the questionnaire process and financial analyses.

The Task IV examination of business risks enhances our understanding of the prospects that co-production plants will be built in the United States. It does this by identifying both the business risks that present the greatest challenges to co-production plants and the risks that the private sector will have the greatest difficulty managing without government financial incentives. Thus, it provides insights to sponsors in key industries and government that cannot be obtained otherwise.

To accomplish the objectives of Task IV, Scully Capital conducted the following five sub-tasks:

- **Sub-task 1 – Develop Questionnaire:** Building on previous risk assessments, including those for new nuclear power plants and integrated gasification combined cycle (IGCC) facilities, Scully Capital developed a questionnaire to explore the significance of potential risks (technical, policy and regulatory, and market) associated with early commercial coal co-production facilities producing power, fuels, and other products. The risk framework is similar to that utilized in a previous effort on IGCC projects presented by DOE at the Gasification Technologies Council's (GTC) spring meeting (May 2004) and EPRI's Coal Fleet

Group (July 2005), as well as in other studies performed by members of the project team. Respondents rated potential project risks in two dimensions: probability of occurrence and severity of impact, should they occur.

- **Sub-task 2 – Develop List of Potential Respondents:** Working with the IPT, Scully Capital developed a list of potential respondents who possess knowledge across the entire transaction chain for the development and financing of co-production facilities.
- **Sub-task 3 – Disseminate Questionnaires and Follow Up:** Scully Capital disseminated 50 questionnaires and followed up with potential respondents. Twenty-two questionnaires were completed and returned to Scully Capital for review. (Two of the responses were not included in the compilation of results due to lack of completeness or other issues.)
- **Sub-task 4 – Analyze Results of Questionnaire Responses:** Scully Capital reviewed, analyzed, and compiled questionnaire responses and ranked the risks within major risk categories and overall. Scully Capital also ranked the risks overall and relative to their probability of occurrence and severity of potential impact. To the extent possible, the responses were further evaluated to identify implications suggested by trends in the responses.
- **Sub-task 5 – Conduct Interviews to "Ground-truth" Results:** Parallel to and subsequent to the process of disseminating and collecting questionnaires and performing financial analyses in other tasks, Scully Capital undertook 17 extended interviews with key agents involved with the co-production facility financing process. Interviewees included representatives of project finance commercial lenders, investment banks, equity investors, rating agencies, mono-line insurers, project developers, and EPC (engineer, procure, construct) contractors. These interviews, which broadly explored the validity of findings from both the questionnaire process and the financial analysis, center on five themes:
  - Capital cost risk;
  - Technology risk;
  - Revenue and output commodity risk;
  - Financing risk and government incentives; and
  - The interrelationships among significant risks.

  Scully Capital summarized the results of these interviews and compared them to the results of the risk ratings and financial analyses.

Overview of Task V.A.

Task V.A. provides an analysis of the impact of selected incentives on the economics and financeability of a co-production plant, particularly with respect to the business risks that the private sector will have the greatest difficulty managing without government incentives. It then provides an evaluation of the potential economic and financial effect on co-production for each potential Federal and state incentive considered to determine the “power of the tool” — the absolute impact of each incentive on the economics of production, product price, and project financeability per dollar of support. It also estimates the potential impact on the Federal budget in terms of tax revenue loss, credit subsidy, and government outlays of applying one or more incentives to a Reference Plant. Then, it comments on the applicability of particular incentives to key risks, as identified by project principals and outside financial experts.

Task V.A. results enhance readers’ understanding of the potential impact of a range of government incentives on the commercial prospects for industrial gasification projects.

To accomplish the objectives of Task V.A., Scully Capital conducted the following four sub-tasks:

- **Sub-task 1 – Research Potential Incentives:** Scully Capital performed research on incentives that have been used to encourage industry and received input from the IPT on potential incentives that could encourage the development of co-production plants.
- **Sub-task 2 – Analyze Incentives:** For each potential Federal and state incentive considered, Scully Capital analyzed its potential economic and financial effect on co-production to determine the “power of the tool” — the absolute impact of each incentive on the economics of production, product price, and project financeability per dollar of support.
- **Sub-task 3 – Determine Budgetary Impact:** For each Federal incentive considered, Scully Capital estimated its potential impact on the Federal budget in terms of tax revenue loss, credit subsidy, and government outlays for each project benefiting from the use of the incentive.
- **Sub-task 4 – Summary and Conclusions:** Scully Capital developed conclusions based on the analysis of the incentives.

Overview of Task V.B.

Task V.B. analyzes the prospects for carbon dioxide sequestration from co-production plants that utilize bituminous and sub-bituminous coal, as well as lignite, and examines the marginal costs of sequestrating carbon dioxide in geologic formations. Then, building on the analysis of the impact of incentives on Reference Plant financial results, it examines the financial impacts of sequestration and the level of incentives that may be required to mitigate them. It examines most closely certain targeted tax incentives for carbon dioxide sequestration.

The analysis shows that incentives of this type are more useful than other incentives (such as loan guarantees and investment tax credits) because they can be structured to align with the marginal cost of sequestration. Investment tax credits are targeted at the *installation*, rather than the *operation*, of sequestration equipment, and while loan guarantees can be used to offset the price of sequestration, they cannot be targeted specifically at sequestration operations.

Task V.B. results provide an analysis of the differing effects of a targeted tax incentive on the economics and financeability of Reference Plants that either sequester the carbon dioxide they produce or use it for EOR purposes. In doing so, the results enhance understanding of government incentives on actual carbon sequestration for industrial gasification projects.[14]

To accomplish the objectives of Task V.B., Scully Capital conducted the following sub-tasks:

- **Sub-task 1 – Research Costs to Sequester Carbon Dioxide:** Scully Capital researched the component costs of sequestering carbon dioxide, including transportation, storage, and monitoring and verification, and included them as capital and operating costs.
- **Sub-task 2 – Develop Reference Case for Sub-Bituminous Coal:** The technical assumptions used to develop a sub-bituminous Reference Plant were derived from the American Energy Security Study sponsored by Southern States Energy Board (SSEB).[15] Scully Capital applied financial assumptions consistent with developing the other Reference Plants.
- **Sub-task 3 – Determine Economic and Financial Effect of Sequestration:** Scully Capital analyzed the three Reference Plants (that use bituminous and sub-bituminous coals and lignite) to determine how sequestration affects the cost of produced fuel.
- **Sub-task 4 – Analyze Incentive Needed to Mitigate Cost Increases:** Scully Capital analyzed potential incentives for sequestration and, for the optimal incentive under existing statutory authority, evaluated the level of a targeted tax incentive needed to encourage sequestration and alleviate the impact of cost increases associated with sequestration. Scully Capital then analyzed the impact of such a tax credit on plant economics, with and without EOR opportunities.
- **Sub-task 5 – Summary and Conclusions:** Scully Capital developed conclusions based on the analysis of the incentive.

[14] It should be noted that the financial impacts of a carbon mitigation policy — Federal or otherwise — are likely to be different than financial analyses in this report. Facilities and firms operating in a “carbon-constrained” environment could face cost structures or levels of control that differ from those presented in this analysis.

[15] “American Energy Security – Building a Bridge to Energy Independence and to a Sustainable Energy Future” The Southern States Energy Board. July 2006. “SSEB Study.”

Overview of Task VI.

Task VI consists of the preparation of a final report that combines the results of Tasks I through V.

E. Report Organization

This report is organized into an Executive Summary, the Introduction, Background, and chapters that report on the results and conclusions of the several tasks, plus three appendices. The chapters of the report are:

Executive Summary

Chapter 1: Introduction

Chapter 2: Background on Energy Production and Consumption, Coal Usage and Reserves, and Co-Production Technology

This chapter provides background material on U.S. energy production and consumption, coal usage and reserves, and technologies employed in coal gasification with co-production facilities.

Chapter 3: Reference Plants and Sensitivity Testing

This chapter provides the technical and financial assumptions for the bituminous coal and lignite Reference Plants, without and with compression of carbon dioxide produced in the plants, as well as the results of the financial analysis and sensitivity testing on input and some output assumptions for the two Reference Plants. It also draws inferences from the analysis with a particular focus on results and conclusions that may be useful in managing key risks associated with, and removing barriers to, early commercial co-production facilities.

Chapter 4: Alternative Plants and Sensitivity Testing

This chapter provides the technical and financial assumptions for Alternative Plants that produce an increased amount of net power at the expense of FT fuels and describes the effects on FT fuel price caused by altering the plant design to increase electricity production. It also presents the results of sensitivity testing on key inputs and some outputs to the alternative plant configurations. It further presents inferences drawn from the analysis that may be useful in managing key risks and identifying barriers for early commercial co-production facilities with higher electricity output

Chapter 5: Business Risk Analysis and Interview Results

This chapter provides a description of the background and approach of the risk rating process, summarizes the responses to the risk questionnaire, provides interpretative analysis of the risk assessment results, and summarizes the results of interviews with key agents involved in the development and financing of co-production facilities. It further draws inferences from the analysis of the risk rating results about the significance of the most important risks and the capacity of the private and public sectors to manage them, and it offers insights about financial parameters for early commercial co-production projects.

Chapter 6: Analysis of Financial Incentives

This chapter provides a description of selected incentives, including tax incentives and credit incentives enacted in the Energy Policy Act of 2005. It provides the results of the analysis of these incentives, including the impact of the incentives on the economics of co-production, the financeability of the Reference Plants, and the Federal budget score associated with the use of each incentive. This section also comments on the applicability of particular incentives in managing key project risks, as identified by project principals and outside financial experts, for early commercial co-production projects.

Chapter 7: Financial Impacts of Sequestering Carbon Dioxide and Analysis of Incentives for Sequestration

This chapter provides technical and cost assumptions associated with sequestration and the results of analyses of the effect on FT fuel price of incorporating these assumptions into the three Reference Plants and the Alternative Plants that sequester carbon dioxide produced by the plants. It also analyzes the economics of using the carbon dioxide in EOR operations and provides, for the Alternative Plants with Sequestration, the impact of increased electricity prices. It then provides the results of the analysis of the type and level of incentives needed to offset the cost of sequestration and of the economic effect on EOR operations of this level of incentive. The chapter also comments on the applicability of particular incentives to key risks for adding sequestration, as identified by principals and experts, and draws inferences that may be useful in managing key risks and identifying barriers for early commercial co-production facilities.

Two appendices follow the main report:

- **Appendix A: Abbreviations and Their Meanings**
- **Appendix B: Plant Schematics and Carbon Balances for Reference Plants**

CHAPTER 2: BACKGROUND ON ENERGY PRODUCTION AND CONSUMPTION, COAL USAGE AND RESERVES, AND CO-PRODUCTION TECHNOLOGY

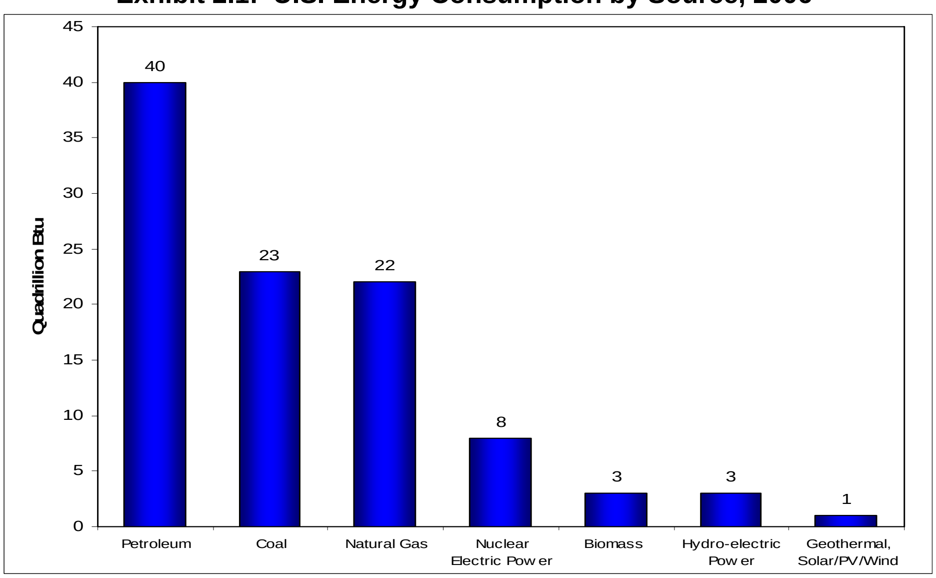
This chapter presents information concerning the use of energy and coal in the United States by providing overviews of:

- U.S. energy production and consumption by fuel source and consumption form;
- Petroleum import and export trends;
- Energy use patterns in the Federal government;
- Coal types and domestic coal resources; and
- The technologies employed in coal gasification with co-production facilities.

A. Overview of U.S. Energy Production and Consumption

The United States economy consumes energy in the production of electricity, provision of heat for buildings, provision of heat and feedstocks for industrial processes, and as the motive force in transportation. In 2006, the United States consumed approximately 100 quadrillion BTUs of energy[1,2] but produced only 71 quadrillion BTUs.

Exhibit 2.1: U.S. Energy Consumption by Source, 2006[3]

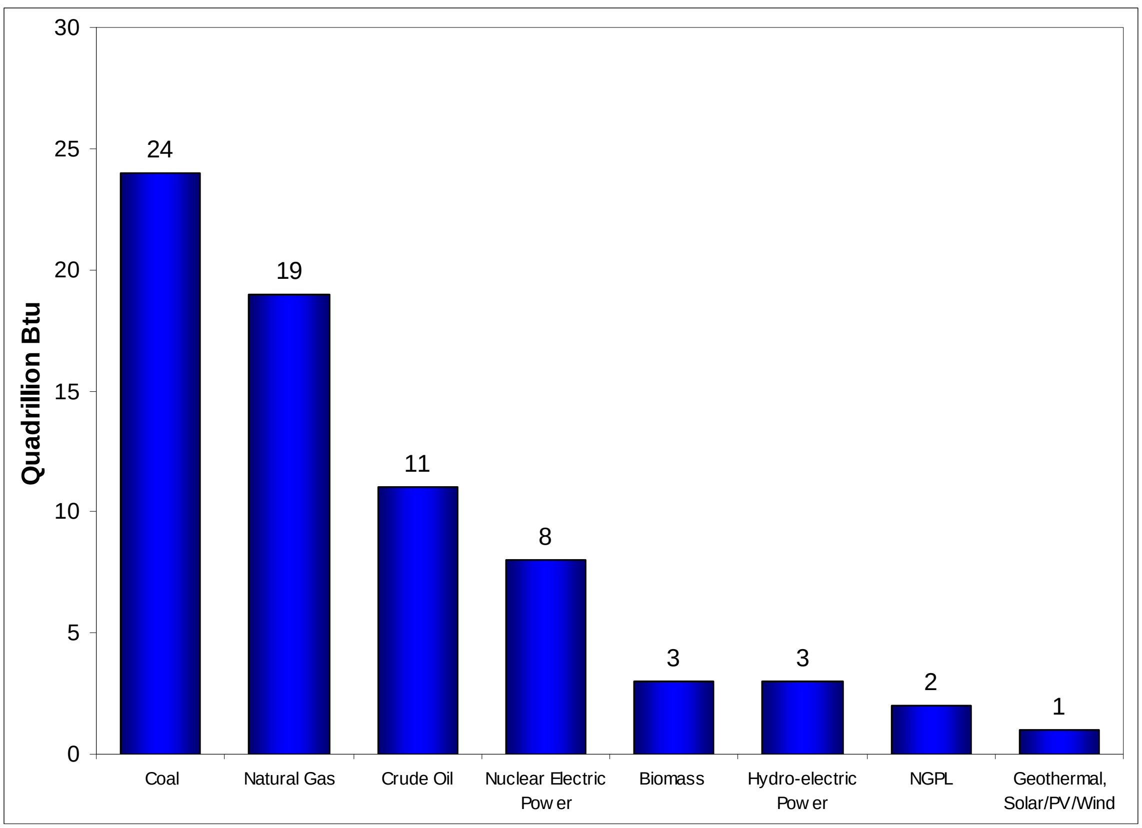


1 "Annual Energy Review – 2006" U.S. Energy Information Administration. June 2007. Page 133.
2 British Thermal Unit (BTU): 1 BTU = energy needed to heat one pound of water by 1° Fahrenheit.
3 "Annual Energy Review – 2006" U.S. Energy Information Administration. June 2007. Page 8.

Exhibit 2.1 charts U.S. energy consumption by source type. This exhibit illustrates that crude oil (or petroleum) provides about 40 percent of energy consumed in the United States, more than any other source. Petroleum, more than 60 percent of which is imported, is used predominantly for transportation purposes. Coal is the second largest source of energy, providing 23 percent of U.S. energy; nearly all coal used in the United States is produced domestically. Natural gas, used primarily in the production of electricity, for space heating, and as an industrial feedstock, is the third largest source of energy used in the United States, with a 22 percent share.

Exhibit 2.2 charts U.S. energy consumption by source type. This exhibit illustrates that crude oil (or petroleum) provides about 40 percent of energy consumed in the United States, more than any other source. Petroleum, more than 60 percent of which is imported, is used predominantly for transportation purposes. Coal is the second largest source of energy, providing 23 percent of U.S. energy; nearly all coal used in the United States is produced domestically. Natural gas, used primarily in the production of electricity, for space heating, and as an industrial feedstock, is the third largest source of energy used in the United States, with a 22 percent share.

Exhibit 2.2: U.S. Energy Production by Source[4]



4 ibid. Page 44.

About 71 percent of energy used in the United States in 2006 was produced domestically. Exhibit 2.2 charts U.S. energy production by source type. This exhibit illustrates that crude oil (or petroleum) is the third largest source of energy produced in the United States, after coal and natural gas. The United States relies on refined petroleum, or crude oil, including natural gas petroleum liquids (NGPL, as indicated with an asterisk in Exhibit 2.1), to meet its transportation energy needs. Coal produced in the United States (24 quadrillion BTUs) comprises almost 34 percent of all U.S. energy production and 23 percent of energy consumed, even though it is not used extensively for such non-electricity generation purposes as industrial processes and transportation fuels.

Exhibit 2.3: Petroleum Use in U.S. Transportation and U.S. Petroleum Imports[5, 6]

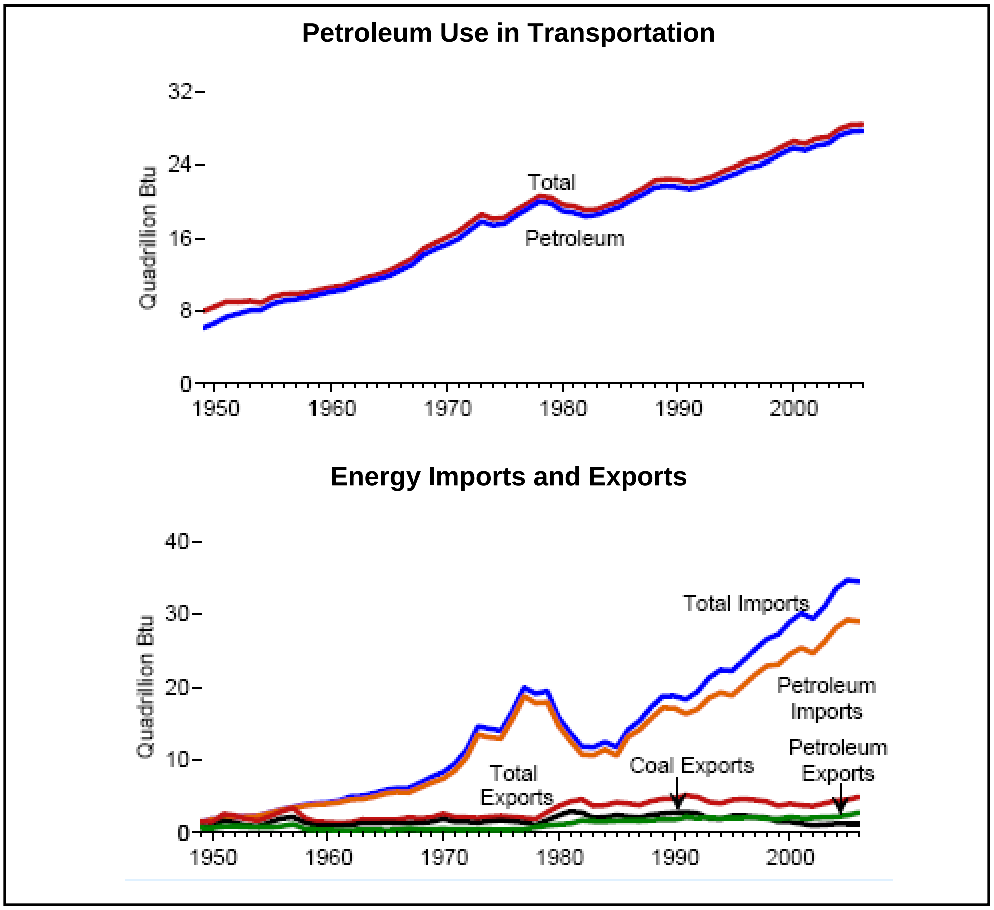


Exhibit 2.3 shows that almost all U.S. transportation energy is derived from petroleum, including natural gas petroleum liquids (NGPL). This exhibit also illustrates the increasing use of imports to satisfy transportation fuel demand. The country imported 58 percent of its crude oil needs in 2004 and 66 percent in 2006, and these imports

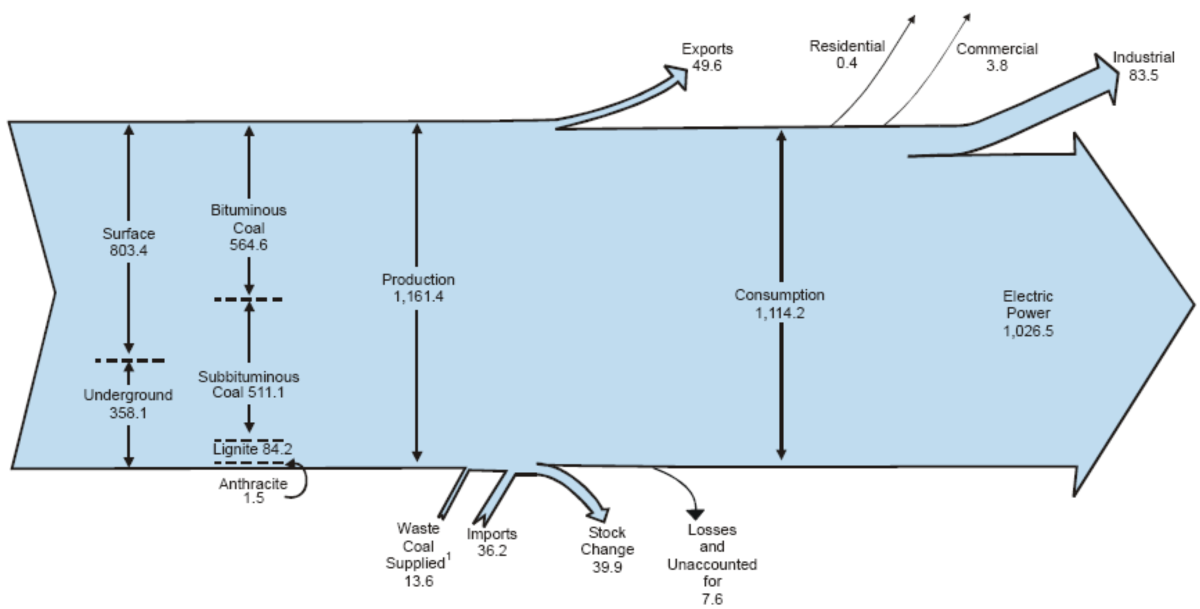
5 "Annual Energy Review – 2006" U.S. Energy Information Administration. June 2007. Page xxi.
6 ibid. Page xxii.

account for 75 percent to 85 percent of the nation's total energy imports. EIA projects that today's higher prices are likely to encourage the development of new domestic oil supplies and curb some demand so that, without other shifts in domestic oil production or consumption patterns, oil imports are likely to be about 66 percent of U.S. needs in 2030.[7] Thus, the transportation sector is, and is likely to continue to be, highly dependent on imported petroleum. A large percentage of petroleum imports originate from countries that lack democratic forms of government or are unstable and that have taken positions that can be considered unfriendly to the long-term interests of the United States. As a result, alternative sources of transportation energy may be able to enhance national security.

B. Coal in Energy Consumption

Coal reserves form the country's largest fossil fuel reserve with 200 years to 250 years of supply at current usage rates.[8] Coal comprises almost 34 percent of U.S. energy consumption, and 92 percent of the energy produced from coal in the United States is used to generate 51 percent of the country's electricity needs. Exhibit 2.4 illustrates U.S. energy uses of coal.

Exhibit 2.4: Coal Flow in Million Short Tons[9]



7 "Annual Energy Outlook – 2007" U.S. Energy Information Administration. February 2007. Page 70 for oil import outlook and page 11 for the 66 percent estimate for 2030.

8 "Assessing the Coal Resources of the United States" U.S. Geological Survey. USGS Fact Sheet FS-157-96. July 1996. USGS is in the process of updating its projections.

9 "Annual Energy Review – 2006" EIA. June 2007. Page 201.

These figures give rise to an increasing interest in the electricity generating industry in co-production, which offers an alternative source of natural gas for power production with stable pricing, a potential additional revenue stream for power generating facilities, a set of technologies that favors lower greenhouse gas emissions, and an opportunity to increase the overall efficiency of electricity generating plants.

In the residential and commercial sectors, coal is consumed primarily indirectly as electric power. Industrial use of coal constitutes less than 1 percent of coal consumption other than as electricity.

Several large segments of U.S. industry are evaluating coal co-production, however, because many industrial processes depend on natural gas. The increasing cost of natural gas and price volatility in natural gas markets have damaged the competitiveness of several energy-intensive U.S. industries, such as fertilizers, glass manufacturing, and steel production, to the point, for example, that capital investment by the U.S. chemicals industry has now shifted overwhelmingly overseas to locations with low-cost natural gas supplies. The ability to convert coal to a natural gas substitute that is less expensive and less subject to price volatility could potentially help some of these industries to regain competitiveness and remain commercially viable, especially if long-term contracts yield stable pricing.

C. Energy Consumption by the Federal Government

As Exhibit 2.5 illustrates, the Federal government is a large consumer of energy, and national defense has historically accounted for the majority of this use. The largest Federal government energy consumer is the military, and more than 75 percent of its energy use is transportation fuel. Military use constitutes two percent of the country's demand for transportation fuels, or 370,000 barrels per day (bpd), of the total approximate national demand of 20 million bpd. Energy use by the Department of Defense (DoD) comprises 17 percent of U.S. aviation fuel consumption,[10] but the composition of its use differs significantly from transportation fuel use in the overall U.S. economy: Jet fuel constitutes 73.5 percent of the military's petroleum use.[11]

Notably, while energy consumption by non-defense agencies has remained relatively constant over time, DoD energy use decreased during the 1990s and has increased since 2001, presumably due to increased DoD activity in Iraq and Afghanistan.

[10] Harrison, William III, and others. "OSD Assured Fuels Initiative: The Drivers for Alternative Aviation Fuels" Presented at Transportation Research Board 2006 Annual Meeting. January 23, 2006.

[11] ibid.

Exhibit 2.5: Energy Use by the Federal Government [12]

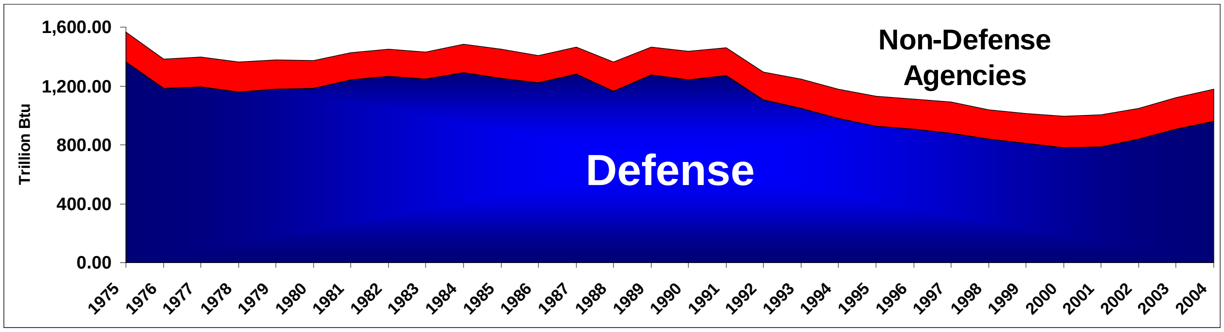
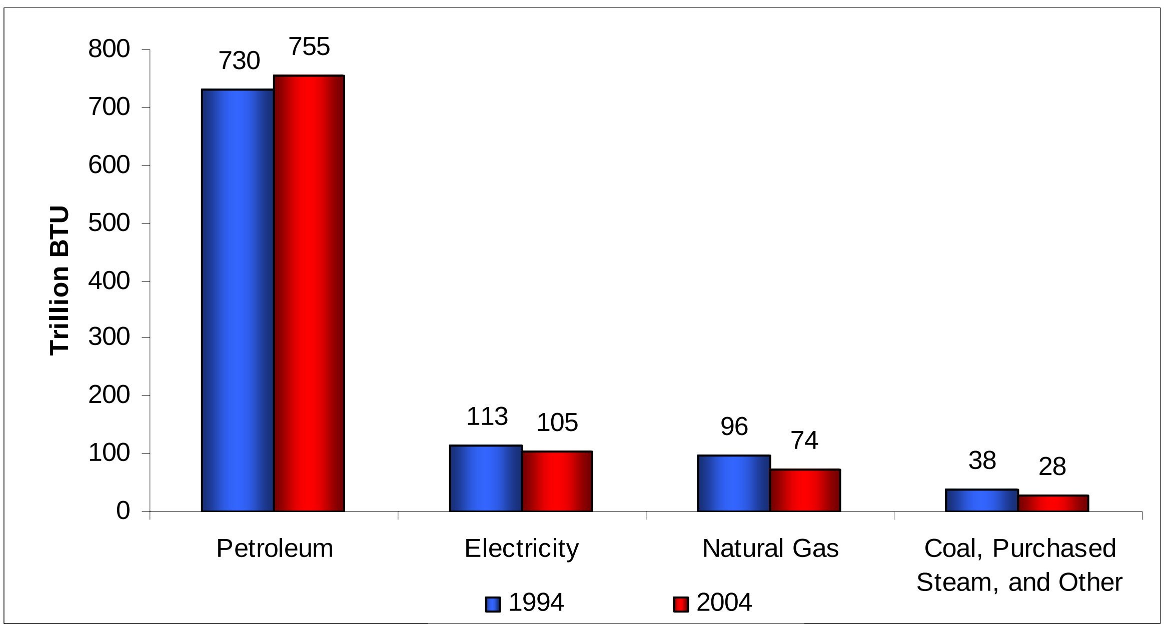


Exhibit 2.6 provides DoD's energy consumption patterns in 1994 and 2004. This exhibit shows that petroleum constituted 78 percent of DoD's total energy consumption in 2004.[13]

Exhibit 2.6: Energy Use by DoD[14]



DoD has made energy security a high priority issue, and the Office of the Secretary of Defense ("OSD") launched the "OSD Assured Fuels Initiative" "to catalyze commercial industry to produce clean fuels for the military from secure domestic resources using environmentally sensitive processes as a bridge to the future."[15] In providing sponsorship for this study, OSD is exploring the possibility that a commercial coal-to-

[12] AER. Page 44.
[13] 78% (755 / (755+105+74+28)).
[14] AER. Page 203.
[15] Shanker, Thom. "Military Plans Test in Search for an Alternative to Oil-Based Fuel" Quote from Michael Aimone. New York Times. May 14, 2006.

liquids industry in the United States could provide DoD with a predictable, stable, and economic source of transportation fuel. Converting a domestic resource like coal into transportation fuels can be accomplished through a co-production plant. So, given the non-domestic nature of most petroleum, pricing volatility, and the potential for supply disruptions, the development of transportation fuels from domestic resources could be considered a national security objective.

As part of this exploration, the Secretary of the Air Force, Secretary Michael W. Wynne, established two major goals for the Air Force in 2006. He directed that the entire fleet be certified to operate on a synthetic fuel blend by early 2011. He also stated that the Air Force will purchase 50 percent of its CONUS (continental US) fuel from domestically produced alternative fuels by 2016 and that these fuels will be environmentally friendly (better than petroleum) and market priced. Already, the Air Force has certified the B-52 (in August 2007) and stood-up the Alternative Fuels Certification Office to take official responsibility for the certification of the remaining fleet. In addition, the Air Force has been an integral partner with the commercial aviation fleet certification program that operates under the Commercial Aviation Alternative Fuels Initiative (CAAFI). It is the goal of CAAFI to certify the commercial fleet to use a synthetic fuel blend (50/50 Jet A/synthetic fuel) by 2008.

D. Coal Types and Coal Resources

An understanding of the types of coal found domestically and the broad characteristics of coal in the United States is essential to visualizing the upper limit of coal's potential use in co-production plants. The qualities of a coal significantly impact the design of a co-production plant. The determination of which type of coal is most appropriate for co-production depends on a number of factors including mining costs, transportation costs, and local conditions.

Principal characteristics of coal include: Heat content (in BTU/lb); water content; ash content; and sulfur content. In general, coal is more desirable if it has a high heat content, low water content (less heat required to gasify coal), low ash content (less waste), and low sulfur content (lower production sulfur dioxide). Coals are broadly classified into four types by their heat content:

- **Anthracite Coal:** Anthracite is considered the highest quality coal due to its heat content of ~15,000 BTU/lb. Anthracite coal burns cleanly without volatile gases.
- **Bituminous Coal:** The heat content of bituminous coal ranges from 10,500 – 14,000 BTU/lb. Bituminous coal is primarily used to produce electricity and steel.
- **Sub-bituminous Coal:** Sub-bituminous coal can have a heat content of 8,000 – 13,000 BTU/lb. It is used primarily in generating electricity.
- **Lignite:** Lignite has the lowest heat content of the 4 major types of coal: 4,000 – 8,000 BTU/lb. Lignite is used primarily for electricity generation.

Exhibit 2.7 presents a picture of U.S. coal resources by variety and location. The exhibit illustrates the widespread distribution of coal reserves in the United States. Significant coal reserves are found in the states along the Appalachian Mountains and the Rocky Mountains, as well as on either side of the Mississippi River. The country has limited anthracite deposits, but large deposits of other types of coal. Given the location of coal deposits, it is most likely that bituminous coal would be used in Midwestern co-production facilities, while lignite would be used in Texas and the northern Great Plains states (e.g., North Dakota). The large sub-bituminous deposits in Wyoming, which are commonly referred to as Powder River Basin (PRB) coal, are notable. These deposits are known for their easy mining and low sulfur content.

Exhibit 2.7: Coal Resources in the United States[16]

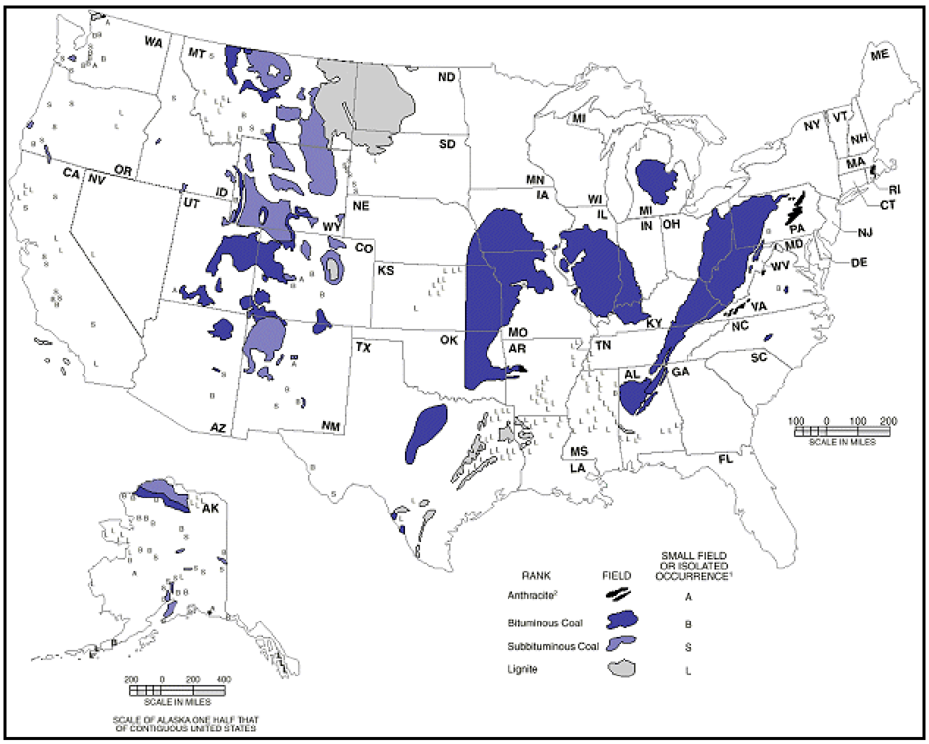
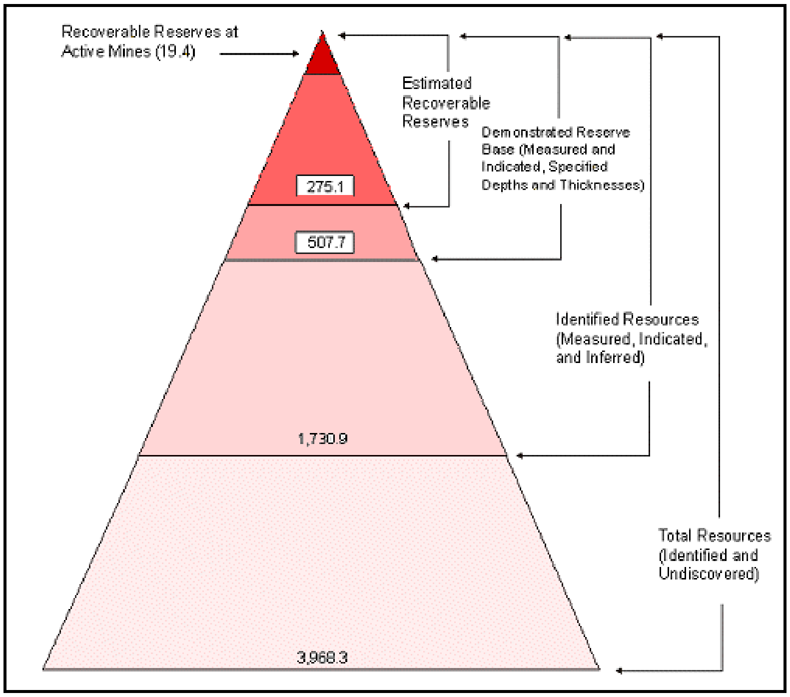


Exhibit 2.8 provides another indication of the coal potential in the country. As this exhibit indicates, active U.S. mines contain only 19.4 billion tons out of approximately 4 trillion tons of coal resources. Estimated recoverable reserves total 275 billion tons, offering the possibility of expanded domestic coal use. These statistics point to the potential for increased use of coal to help the country address energy security concerns.

[16] EIA. http://www.eia.doe.gov/cneaf/coal/reserves/chapter1.html.

Exhibit 2.8: Domestic Coal Potential (in Billion Short Tons)[17]



Thus, the country has large domestic resources of coal, a national security need to consider replacing some imported petroleum with domestic transportation fuel, and the availability of technology (which, though, has not been used commercially in the United States) to convert coal into transportation fuels.

E. Gasification with Co-Production Technology Overview

Co-production includes gasifying input feedstocks (e.g., coal, petcoke, and, potentially, biomass) to produce a gaseous product mix of carbon monoxide and hydrogen ("syngas") and by-products, including carbon dioxide. As the block diagram in Exhibit 2.9 shows, the syngas is then converted in various chemical processes to any of a range of outputs and/or used to generate electricity. Products created through co-production processes can be varied, and the configuration of a plant determines the possible output products and their cost of production. For example, the production of transportation fuel requires a chemical process that converts syngas into a liquid which, depending on operating severity, could include wax, diesel, jet fuel, and naphtha boiling-range components. This reaction also produces naphtha which can be sold as a co-product. The two main technologies involved in creating transportation fuel from coal are coal gasification and the Fischer-Tropsch process (the "FT process").

Gasification converts the hydrocarbons in coal into a syngas, and the FT process subsequently converts the syngas into liquid fuels (usually FT diesel or FT aviation fuel).

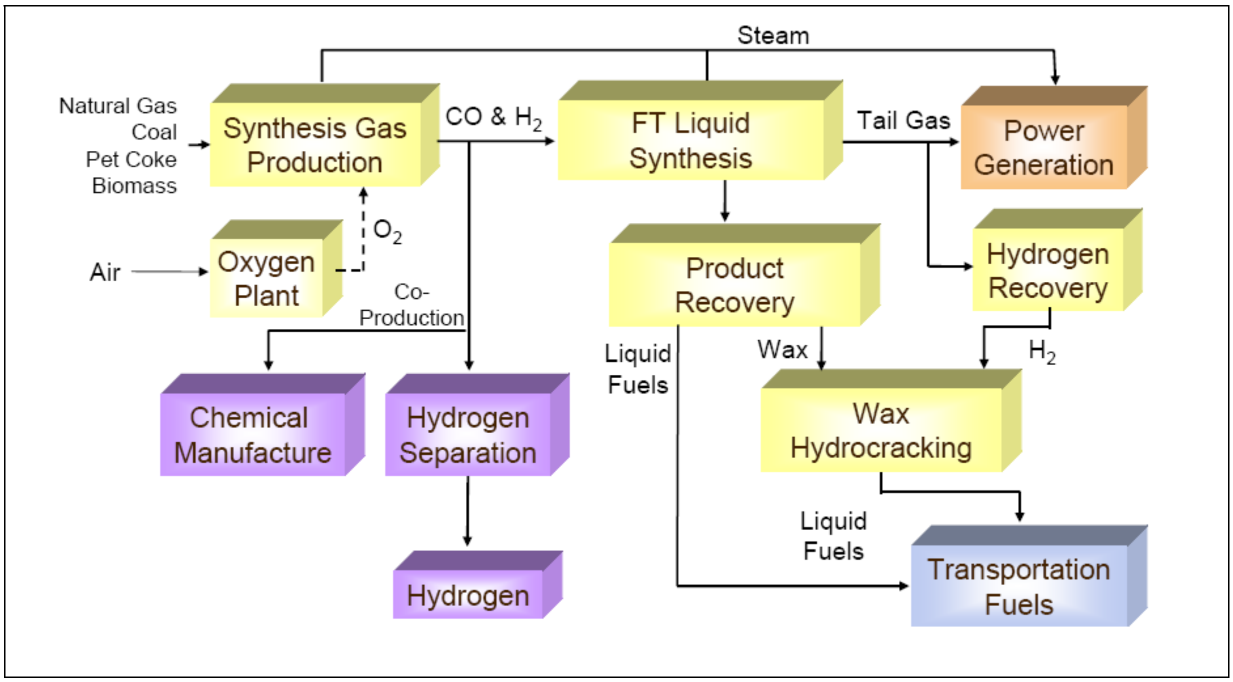
[17] ibid.

Syngas can be used as a fuel gas to serve the energy needs of industry or as a feedstock for many industrial processes that use natural gas as a feedstock. The technology of gasification and gas cleanup has improved significantly in recent years; now, gasification syngas is virtually devoid of mercury and contaminants that would produce such pollutants as sulfur oxides, nitrous oxides, and other particulate matter.

Without carbon sequestration, FT fuels are up to twice as carbon intensive on a "well-to-wheels" basis as petroleum-based fuels. As noted earlier, however, with the capture and sequestration of carbon dioxide produced in the gasifiers and FT process, FT fuels based on coal can be slightly less carbon-intensive than petroleum-based fuels.[18]

In sum, gasification allows coal to be combusted almost as cleanly as natural gas to generate power. The syngas can be combusted in gas turbines to generate electricity (in a combined cycle power block), as in an Integrated Gasification Combined Cycle ("IGCC") plant. Or, an FT unit can convert the syngas to ultra-clean transportation fuels or, in various industrial processes, to methanol, dimethyl ether, hydrogen, or ammonia-based fertilizer.

Exhibit 2.9: Co-Production Technology Overview[19]



[18] Unpublished paper. DOE/National Energy Technology Laboratory (NETL). August 2007. The results may vary by a few percent in either direction depending on the type of production process used in the plant, the plant's source of electricity, and the type of oil used in the comparison.

[19] "The Economic Viability of an FT Facility Using PRB Coals" Rentech, Inc. Presented to the Wyoming Governor's Office and the Wyoming Business Council. April 14, 2005.

Exhibit 2.9 illustrates the major processes in a co-production facility, including gasification, production of power in a combined cycle power block, FT units, and wax hydrocracking. (Environmental controls, including those used for carbon capture and compression, are not shown, and other industrial processes are not included in this particular co-production plant.) The major processes include:

- **Syngas Production (Gasification):** This process, which operates at high temperatures and with oxygen and steam, involves the chemical conversion of coal into syngas, a gaseous mixture of hydrogen and carbon monoxide. After gasification, the syngas is cleaned of particulates and other contaminants including mercury, sulfur, ammonia, chlorides, and carbon dioxide.

  The carbon dioxide generated in the gasification step (and, later, in the FT unit) is separated from the syngas stream (see schematics for plants using three types of coal in Appendix B) to improve the quality of the syngas, and at least 75 percent to roughly 90 percent of the carbon dioxide can be captured readily. The significant amount of carbon dioxide produced during the cleanup of syngas is not used (and actually would diminish the value of the syngas or reduce process efficiency if it were not removed). The captured carbon dioxide can be compressed and piped to a location where it can be used productively or enter long-term storage. Thus, the gasification process eases and reduces the cost of the sequestration or re-use of carbon dioxide generated in this unit process (as well as in the production of FT fuels). In a potentially carbon-constrained environment, this attribute that allows coal to be used in an environmentally sustainable manner may prove important.

- **Power Generation (Combined Cycle Power Block):** A portion of the syngas can be fed into combustion turbines which produce electric power. In addition, a steam generator can utilize the hot exhaust gas from the combustion turbine (and the FT unit) to produce steam, which then turns a steam turbine to power a second electric generator.

- **FT Liquid Synthesis (FT Unit):** FT units convert syngas into a variety of hydrocarbons including wax, which is refined later into transportation fuels. The process to create the wax is exothermic (i.e., it releases heat). This excess heat runs the steam generator in the power block. A major challenge in converting syngas produced from coal into a wax is the hydrogen-to-carbon molecular ratio ("H/C ratio"). The H/C ratio for diesel is approximately 2 and for crude oil it is about 1.3 to 1.9; for bituminous coal (the different types of coal are explained elsewhere in this chapter), though, it is approximately 0.8.[20] The H/C ratio of the syngas is changed in a process known as the water-gas-shift (WGS) reaction in which the carbon monoxide in the synthesis gas is reacted with water to produce carbon dioxide and additional hydrogen.

[20] Rezaiyan, J., McVeigh, J., Menendez, J. "Assessing the Economic Potential of IGCC Innovation with Liquids Sparing" Princeton Energy Resources International, LLC. June 24, 2005.

The capture (though not the compression, transport, or sequestration) of the carbon dioxide is integral to the operation of the CTL process; it occurs during product recovery and upgrading. Thus, in using the captured carbon dioxide for enhanced oil recovery with sequestration or in otherwise sequestering it permanently in the ground, the added capital and operating costs arise primarily from its compression, transportation in a pipeline, and pumping into the ground (see schematics for plants using three types of coal in Appendix B).

- **Wax Hydrocracking (Refining):** The products created from the FT unit are refined to produce diesel and jet fuel in the desired proportion.
- **Chemical Manufacture/Hydrogen/Pipeline Gas:** The syngas produced by the gasification process can be used for many purposes (not shown in Exhibit 2.6), including the production of ammonia (which can be used in making fertilizer), methanol, and dimethyl ether. Hydrogen can be separated from the syngas and sold separately. Alternatively, the syngas can be processed in a methanator to produce pipeline-quality gas.

CHAPTER 3: REFERENCE PLANTS AND SENSITIVITY TESTING

I. INTRODUCTION

A. Objectives and Approach

This chapter provides the results of analyses conducted in Tasks I and II of this study of the financial prospects for mid-sized coal-based co-production Reference Plants that utilize either bituminous coal or lignite with an appropriate financing structure and sensitivity testing on several key project inputs and outputs. The Reference Plants are optimized for transportation fuel production with and without carbon capture and compression. In performing Tasks I and II, which are the basis of this chapter, Scully Capital conducted eight sub-tasks (see list in Chapter 1).

B. Chapter Organization

This chapter is organized into three sections:

- **Technical and Financial Assumptions for Reference Plants:** This section discusses the technical and financial assumptions used in developing the Reference Plants.
- **Reference Plant Results and Sensitivity Testing:** This section presents the results of the study's analysis. In particular, it presents general qualitative findings, as well as quantitative findings, for each of the Reference Plants and sensitivity testing on input assumptions.
- **Summary and Conclusions:** This section summarizes the findings and draws inferences from the analysis with particular focus on results and conclusions that may be useful in removing barriers to early commercial co-production facilities.

II. TECHNICAL AND FINANCIAL ASSUMPTIONS FOR REFERENCE PLANTS

This section presents the technical and financial assumptions for the analysis of two mid-sized (approximately 30,000 bpd) reference configuration co-production plants. One Reference Plant uses bituminous coal, while the other utilizes lignite, and both plants capture (separate) the carbon dioxide before the gaseous mixture arrives at the FT unit to enable more efficient operation of the FT reactor and obtain the proper H/C ratio. A case with both carbon capture and compression ("CC&C") is also considered for each Reference Plant. In the "with CC&C" cases, at least 75 percent of the carbon dioxide generated from plant operations is captured and compressed. A non-recourse project financing structure is then applied to the technical assumptions to build a financial model for each Reference Plant.

Scully Capital based its analysis on a "greenfield" plant that could be viewed as indicative of the type of co-production plant which would be considered for early commercial facilities. After considerable research, Scully Capital found that previous analyses of co-production were outdated, but a number of studies on the subject were underway.

The technical assumptions used in this study were derived from the American Energy Security Study (AES Study) sponsored by Southern States Energy Board (SSEB)[1] and conducted by Mitretek (now Noblis). The aim of the AES Study is to provide fiscal, tax, legislative, and regulatory recommendations to Congress that could "jumpstart" private sector involvement in a new domestic alternative liquid fuels industry. The SSEB shared its pre-published results with Scully Capital, providing timely and essential input to the current study. The sections that follow provide the detailed technical assumptions developed by SSEB and Mitretek. These sections also detail the assumptions related to carbon capture and compression and discuss their possible effects on the eventual cost of CC&C.

Importantly, the Mitretek cost estimates were preliminary in nature and could vary by +/- 30 percent.[2] In the two years since these cost estimates were developed, sources consulted for this study indicate that the cost of capital-intensive projects have escalated significantly (to as much as 135–175 percent of base costs, although some widely used indices of equipment and construction cost grew at lesser rates over this period[3]). To evaluate the significance of capital cost increases, Scully Capital performed sensitivity testing which showed, for example, the effect of an increase of 25

1 "American Energy Security – Building a Bridge to Energy Independence and to a Sustainable Energy Future" The Southern States Energy Board. July 2006. "AES Study"
2 ibid. Appendix D. Page 16.
3 The Marshall & Swift Equipment Cost Index – Electric Power Sector increased by 5.6% in 2005, 4.7% in 2006, and 5.5% in 2007. The Chemical Engineering Plant Cost Index increased by 5.4% in 2005, 6.8% in 2006, and 5.4% in 2007.

percent in capital costs. In addition, site-specific characteristics that could affect plant cost were not incorporated into the analysis. For example, a proximity to industrial users may permit a project owner to obtain a higher price for naphtha than used in the financial modeling. Given the multitude of possible variations, Scully Capital used a non-site-specific configuration to better understand the economics of the plant and in performing sensitivity analyses on some of the possible benefits and costs relating to specific sites. Benefits and costs were examined in other project tasks. So, it is important to consider the results presented in this report to be preliminary ranges that would be further refined based on project-specific characteristics and detailed project-specific engineering.

A. Assumptions for Bituminous Coal-Based Co-Production Plant

1. Plant Characteristics

Exhibit 3.1 presents the input characteristics, output characteristics, and general plant characteristics of the bituminous coal Reference Plant.[4]

Exhibit 3.1: Technical Assumptions for Bituminous Coal Co-Production Plant

Input Characteristics	
Tons of Coal Per Day	17,987
BTU Value of Bituminous Coal	11,800
Price of Coal Delivered	$36 / Short Ton
Output Characteristics @ Capacity	
FT Liquids (bpd)	
FT Diesel	24,359
Naptha	11,398
Total: FT Diesel Equivalent	32,502
Electricity Production	
Gross (MWe)	725
Net (MWe)	257
Net (MWe) with CC&C	205
Plant Characteristics	
Efficiency (HHV)	48%
Gasifier Trains	6
Spare Gasifier	No
FT Reactors	6
Other Characteristics	
Construction Time	3 Years
Availability	
1st Year	51%
2nd Year	81%
3rd+ Year	90%

[4] See Appendix B for a schematic of the Reference Plant that uses bituminous coal, including the carbon balance for this plant.

Exhibit 3.1 shows that the plant consumes 17,987 tons per day (tpd) of bituminous coal to produce 32,502 barrels per day (bpd) of FT liquids. While the plant produces 24,359 barrels of FT diesel, the process also produces a sizeable quantity of less valuable naphtha. Assuming naphtha has 71 percent of the energy value of FT diesel, naphtha production is approximately 25 percent (11,398 * 71% / 32,502) of total FT equivalent diesel production (24,359 + 71% * 11,398 = 32,502). It is worth noting that the plant consumes most of the electricity produced in the power block. In fact, the plant's parasitic load is 65 percent ([725 - 257] / 725) with CC, and 72 percent with CC&C.

Scully Capital confirmed with industry experts that the large number of gasifiers (6) all but eliminates the need for a spare gasifier. Scully Capital informally confirmed with industry participants the three-year availability ramp-up profile (51 percent, 81 percent, and 90 percent). The availability numbers relate to the total theoretical capacity of the plant.

Scully Capital assumed that the plant would be based in Ohio with access to barge and rail lines. There would be strong regional and local support for building the facility. The facility would have access to back-up natural gas supplies and would benefit from sufficient transmission capacity for export electricity sales. In the carbon capture and compression (CC&C) case, Scully Capital assumed that the necessary infrastructure to accept compressed carbon dioxide would be available at the "plant-gate." The costs related to transportation of the carbon dioxide to a storage site and permanent sequestration are not considered in the Reference Plant analyses since this cost (or benefit) would vary from site to site. Accordingly, the Reference Plant analysis neither considered costs (or benefits) to transport the carbon dioxide from the plant-gate to EOR sites nor the revenue benefits to the plant from sale of carbon dioxide to the EOR operation; this analysis also did not consider costs associated with permanently sequestering the carbon dioxide in geologic formations.

2. Construction Costs

Exhibit 3.2 provides the construction costs of the bituminous coal co-production Reference Plant that uses bituminous coal. This exhibit presents the picture of a large chemical plant requiring a sizeable initial investment. The overnight capital cost of the plant is $2.56 billion. The additional cost of carbon compression equipment is approximately $53 million, increasing the overnight capital cost of the plant equipped for CC&C to $2.61 billion.

The largest capital cost items — gasification, gas cleanup, and sulfur polishing — comprise 29 percent of total capital costs, and other significant capital costs include the FT reactor (14 percent) and the power block (11 percent). License fees are estimated to be $25 million, with startup costs set to the first three months of operating costs.

Exhibit 3.2: Overnight Capital Cost for Bituminous Coal Reference Plant

Overnight Plant Costs (2006 $ millions)						
Cost Item	With CC			With CC&C		
Solids Handling	$	163	6%	$	163	6%
Air Separation Unit		256	10%		256	10%
Gasification		460	18%		460	18%
F-T Liquids Area + Refining		362	14%		362	14%
Power Block		290	11%		290	11%
Gas Cleanup/Polishing		294	11%		294	11%
Carbon Compression Equip.		-	0%		53	2%
Balance of Plant		345	13%		345	13%
Owner's Contingency		108	4%		111	4%
License Fees & Startup Costs		90	4%		90	3%
Design Costs		187	7%		187	7%
Total Plant Costs	**$**	**2,555**	**100%**	**$**	**2,611**	**100%**

3. Operating Costs

Exhibit 3.3 provides the operating costs of the bituminous coal-based Reference Plant.

Exhibit 3.3: Operating Costs for Bituminous Coal Reference Plant

Operating Costs at 90% Utliization (2006 $ millions)			
Coal	$	213	57%
Catalysts & Chemicals		24	7%
Labor/Overhead		50	13%
Administrative		8	2%
Local Taxes & Insurance		51	14%
Maintenance		22	6%
Royalties		4	1%
Total Operating Costs	**$**	**373**	**100%**

The cost of coal comprises 50 percent of the annual $404 million operating cost of this co-production plant. Operating costs do not differ significantly between CC and CC&C; the cost of operating compression equipment is embedded in the increase in the parasitic load which decreases the net sale of electricity to the grid.

B. Assumptions for a Lignite Co-Production Plant

1. Plant Characteristics

Exhibit 3.4 presents the input characteristics, output characteristics, plant characteristics, and construction and availability characteristics of the Reference Plant that uses lignite.[5]

Exhibit 3.4: Technical Assumptions for Lignite Reference Plant

Input Characteristics	
Tons of Coal Per Day	33,697
BTU Value of Lignite Coal	6,500
Price of Coal Delivered	$10 / Short Ton
Output Characteristics @ Capacity	
FT Liquids (bpd)	
FT Diesel	24,284
Naptha	11,362
Total: FT Diesel Equivalent	32,401
Electricity Production	
Gross (MWe)	617
Net (MWe)	144
Net (MWe) with CC&C	91
Plant Characteristics	
Efficiency (HHV)	46%
Gasifier Trains	8
Spare Gasifier	No
FT Reactors	6
Other Characteristics	
Construction Time	3 Years
Availability	
1st Year	51%
2nd Year	81%
3rd+ Year	90%

The lignite-based plant, with its lower-BTU coal, consumes 33,697 tons of coal per day, almost double the input required for a plant using bituminous coal. However, the price of lignite is less than one-third that of bituminous coal ($10 vs. $36 per short ton, respectively). The lignite plant produces approximately equivalent amounts of FT diesel (24,284 bpd) and naphtha (11,362 bpd) compared with the bituminous coal Reference Plant, resulting in a total of 32,401 bpd of FT diesel equivalent. In addition, the lignite-based plant has a larger parasitic load. In the base configuration (with carbon capture), the lignite-based plant consumes 77 percent of the electricity it produces, while in the CC&C configuration this figure increases to 85 percent. The parasitic load of a lignite co-production plant requires additional electricity consumption to handle larger amounts

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[5] See Appendix B for a schematic of the Reference Plant that uses lignite, including the carbon balance for this plant.

of coal and to power extra gasifiers (8 in the lignite plants versus 6 in the bituminous cases). As in the bituminous case, a spare gasifier is not required; availability during ramp-up is similar. Thus, the Reference Plant uses 33,696 tons of lignite per day to produce 32,401 barrels of FT-equivalent diesel fuel.

The analysis assumes that the plant would be based in North Dakota near the mouth of a lignite mine and that strong regional and local support for building the facility exists. The facility would have access to back-up natural gas supplies and would benefit from sufficient transmission capacity for export electricity. In CC&C case, Scully Capital modeled the cost of compressing the carbon dioxide captured after the gasification step. Potentially, the carbon dioxide could then be permanently stored in, for example, a briny aquifer or shipped in the existing carbon dioxide pipeline to Canada for use in EOR.[6]

2. Construction Costs

Exhibit 3.5 provides the construction costs of the lignite-based Reference Plant.

Exhibit 3.5: Overnight Capital Cost for Lignite Reference Plant

Overnight Plant Costs (2006 $ millions)						
Cost Item	With CC			With CC&C		
Solids Handling	$	262	9%	$	262	9%
Air Separation Unit		189	7%		189	7%
Gasification		614	22%		614	21%
F-T Liquids Area + Refining		355	13%		355	12%
Power Block		269	10%		269	9%
Gas Cleanup/Polishing		334	12%		334	12%
Carbon Compression Equip.		-	0%		57	2%
Balance of Plant		394	14%		394	14%
Owner's Contingency		121	4%		124	4%
License Fees & Startup Costs		81	3%		81	3%
Design Costs		208	7%		208	7%
Total Plant Costs	**$**	**2,827**	**100%**	**$**	**2,886**	**100%**

The capital cost of the lignite-based plant is approximately 11 percent greater than that of the bituminous coal Reference Plant: $2.83 billion for a lignite plant with CC and $2.87 billion with CC&C. The difference between the lignite and bituminous coal plants traces to the additional costs of handling extra tonnage of coal (solids handling), more gasifiers (8 versus 6 in the bituminous coal cases), and extra gas cleanup equipment. As a result, gasification, gas cleanup, and sulfur polishing represent 34 percent of total

[6] DOE's Office of Fossil Energy (FE) has produced estimates of recoverable oil from EOR in the Williston Basin for North Dakota. More information can be found in the following report: DOE – FE/Office of Oil and Gas. "Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Williston Basin" Prepared by Advanced Strategies, Inc. February 2006.

plant costs, an increase of 5 percent from the bituminous coal case, and solids handling represents 9 percent of the total cost, up from 6 percent in the bituminous coal case.

3. Operating Cost

Exhibit 3.6 provides the operating costs of the lignite-based co-production Reference Plant. As noted earlier, operating costs do not differ significantly between CC and CC&C plants. The annual cost of operating a lignite co-production plant appears to be less than that for a bituminous coal-based plant. The lower price of lignite is not offset by the higher quantity used, so the net cost of coal is $123 million, 45 percent less than the cost of coal in the bituminous Reference Plant.

Exhibit 3.6: Operating Costs for Lignite Reference Plant

Operating Costs at 90% Utliization (2006 $ millions)			
Coal	$	111	37%
Catalysts & Chemicals		28	9%
Labor/Overhead		55	18%
Administrative		9	3%
Local Taxes & Insurance		57	19%
Maintenance		25	8%
Royalties		4	1%
Other		12	4%
Total Operating Costs	**$**	**301**	**100%**

C. Carbon Capture and Compression Assumptions

The cost of CC&C includes the cost of capturing the carbon dioxide, which is embedded in the capital and operating cost of the Reference Plants, and compressing it. As discussed in the technology background section, carbon dioxide is removed after the gasifiers (before the gaseous mixture arrives at the FT unit) to enhance operational efficiency in the FT reactor and obtain the proper H/C ratio. Additional carbon dioxide is removed after the FT unit during product recovery and upgrading. Thus, the marginal capital cost of CC&C is the cost of compression equipment, which is estimated to be in the $50–$60 million range for a plant of this size and type. Likewise, the marginal operating cost of CC&C is due to the increase in parasitic load needed to compress the carbon dioxide that has been captured in two locations within the plant. The AES Study estimates that the parasitic load increase is in the range of 50–55 MWe.

Based on input from the AES Study, Scully Capital also assumes that the carbon dioxide generated by the plant plus carbon dioxide in fuel it produces would be roughly equivalent to the input tonnage of bituminous coal. That is, for every ton of bituminous coal received, the plant and combustion of the fuel it produces would generate about one ton of carbon in the form of carbon dioxide. Although the potential carbon capture rate for the plant may be as high as 95 percent, to be conservative Scully Capital further assumes that about 75 percent of the carbon dioxide generated during gasification would be captured and compressed, and about one-third of all carbon in the coal would be in FT fuels produced by the plant.

The financial results of CC&C depend heavily on these technical assumptions. The IPT raised concerns that these costs may be understated. However, in light of the lack of other reliable engineering cost data, Scully Capital used the SSEB assumptions to estimate costs relating to CC&C, though it recognizes that the SSEB engineering data is preliminary in nature and notes that these estimates do not incorporate the cost of sequestration or potential revenues from EOR.

D. Financing and Output Pricing Assumptions

Scully Capital used its experience in project finance, corporate finance, and energy markets to determine the proper assumptions in creating a financing structure for each of the Reference Plants. As a result, the plants were modeled under a non-recourse project financing structure. Under this type of financing structure, a project "stands on its own" and its cash flows provide the underpinnings of creditworthiness. Conversations with developers and financiers indicated that this type of structure would likely be utilized for the first few plants. Importantly, this structure insulates project sponsors from the full risk of the project, allowing risks to be shared by several participants in the project. Project equity could be sourced from a number of market participants, such as strategic investors (technology, energy companies) or financial investors (private equity, pension funds, insurance funds), and equity could be supplemented by in-kind payments from local governments. The following financial assumptions were used:

- Capital structure: 30 percent equity, 70 percent debt;
- Interest rate: 8 percent annual;
- Amortization: 15 years with mortgage-style debt amortization;[7]
- Reserves: Debt service reserves capitalized at 50 percent of maximum annual debt service;
- Interest capitalization: Capitalized during construction and first year of operation (during ramp-up);
- After-tax equity internal rate of return range for equity: 17 percent to 19 percent;
- Marginal income tax rate: 40 percent;
- Tax loss benefits: Utilized currently;
- Other costs:

[7] The debt was assumed to be coterminous with the length of purchase agreement with a creditworthy counterparty.

- Development costs: 2.5 percent of EPC;
- Owner's contingency: 5 percent of EPC; and
- Financial closing costs: $50 million.

This financing structure assumes that each output will be sold at a constant rate, with increases limited by a pre-determined escalation factor (2 percent, unless noted otherwise). Scully Capital assumes that naphtha would be sold at $30 per barrel, while the output electricity would be sold at 5.86 cents/kWh (inflated at 1 percent annually). Scully Capital further assumes that sulfur produced from the plant would be sold in the current market, which would yield revenues of $13.8 million in 2006 dollars if the plant operates at 90 percent availability. Finally, Scully Capital assumes that the generation of slag would be "revenue neutral"; that is, the cost of disposing of the slag would be offset by revenues from the slag sales. Based on this pricing for the co-production of naphtha, sulfur, and electricity, Scully Capital adjusted the price of FT diesel until a target IRR of 17 percent to 19 percent was achieved.

The price of FT diesel resulting from this analysis represents the price of crude oil equivalent, plus the cost of refining the product. It does not include distribution, marketing, or taxes. An industry proxy utilized for conversion to a crude-equivalent price consists of multiplying the crude oil price by 1.3 to arrive at the equivalent price of diesel. For example, if the FT diesel price was $72.80 per barrel, the equivalent price for crude oil would be $56.00 per barrel. While FT fuel contains a *de minimus* quantity of sulfur, a premium for ultra-low sulfur diesel was not monetized in this analysis because of uncertainty for the premium over time and for conservatism in financial projections.

It is important to note that, in light of price volatility in crude oil (and natural gas) markets, the credit rating agencies utilize a long-term crude oil price assumption in performing credit analyses of energy-related projects. Standard & Poor's (S&P), for example, utilizes $40 per barrel as its long-term crude oil price assumption in performing credit analyses.[8] This figure provides a conservative estimate for evaluating long-term creditworthiness of an energy project, and it is used in this study as a basis to determine the long-term sustainability of a plant's fuel production operations. If the FT fuel price necessary to achieve 17 percent or 19 percent IRR is greater than this floor price, for instance, project developers will face difficulty in obtaining financing (both equity and debt) for a co-production project.

[8] "Industry Report Card: Diverging Natural Gas And Crude Oil Prices Result In A Mixed U.S. Oil And Gas Outlook" Table 1 on page 6. Standard & Poor's. September 11, 2007.

III. REFERENCE PLANT RESULTS AND SENSITIVITY TESTING

This section presents the Reference Plant results for the 30,000 bpd bituminous coal and lignite co-production projects both with CC and with CC&C. Scully Capital's analysis is based on a "greenfield" Reference Plant, which can be viewed as indicative of the type and character of early commercial co-production plants. For each configuration, Scully Capital determined the results at internal rates of return ("IRR") of 17 percent and 19 percent, after-tax.

Finally, sensitivity testing on one of the reference configurations was conducted.[9] In this analysis, numerous input criteria were altered to determine the effects on the price of FT fuel. For sensitivity tests on the Reference Plant, Scully Capital changed the price of FT diesel fuel until the target IRR was achieved.

This section is organized in the following sub-sections:

- General Findings;
- Reference Plant Sources and Uses for Bituminous and Lignite Co-Production Plants;
- Reference Plant Results for Bituminous and Lignite Co-Production Plants;
- Sensitivity Testing; and
- Summary of Reference Plant and Sensitivity Tests.

It is important to note that the findings are based on a design with +/- 30 percent cost accuracy. In addition, the benefits and costs associated with site-specific characteristics were excluded. These benefits and costs can be significant in nature, and their inclusion could materially change the findings for a specific project.

A. General Findings

Scully Capital found that, in general, industry is reluctant to provide comparative information regarding plant cost information, possible configurations, and the effects of plant scaling. Scully Capital determined that, given the large capital investment required for a mid-size co-production plant and the use and integration of technologies that are relatively unproven commercially, the ability of contractors to provide the performance wrap necessary for financing such a project will be limited.

The co-production aspects of any plant will depend on its location. Location will affect the price received, for example, for electricity, naphtha, and other co-products.

9 The sensitivity of one configuration to variables provides insights for the other configurations.

Likewise, if the plant is proximate to oil wells that use carbon dioxide for enhanced oil recovery ("EOR"), the economics of co-production could improve.

Based on conversations with industry experts and on analytical modeling, Scully Capital determined that the following generalizations apply to co-production:

- Given the current pricing for transportation fuels and electricity, net electricity output should be limited and electricity generated should be used primarily for internal purposes;
- For smaller plants, a thermal-only unit for electricity generation may be optimal;
- Spare gasifiers may not be required for mid-sized co-production plants; and
- A lower percentage of naphtha to total FT fuel output is generally preferable.

B. Reference Plant Sources and Uses for Bituminous Coal and Lignite Co-Production Plants[10]

Scully Capital populated its financial model based on the technical and financial assumptions developed the Reference Plant (provided above), which are detailed in the following section.

1. Sources and Uses for Bituminous Coal Reference Plant

Exhibit 3.7 presents the sources and uses statement for the Reference Plant that usese bituminous coal. This exhibit shows that, while the overnight capital cost of this Reference Plant is $2.56 billion, the total plant cost financed is $3.27 billion. For the same Reference Plant with CC&C, the total financed cost is $3.34 billion. As noted earlier in the technical assumptions, the capital cost of compression equipment is the marginal expense associated with CC&C. The difference between the overnight capital costs presented in Exhibit 3.2 and total financed cost can be attributed to inflating overnight costs through the three-year construction period and financing the uses of funds (capitalizing interest, debt service reserve, closing costs). The uses of funds are financed by $981 million in equity and $2.29 billion in debt for the CC case, and $1 billion in equity and $2.34 billion in debt for the CC&C case.

[10] Prices obtained for FT diesel fuel in the current study differ from AES Study results. The differences arise from disparate financing and inflation assumptions, including, but not limited to assumptions concerning target IRR, development expense, debt service reserve fund, and inflation expectations.

Exhibit 3.7: Sources and Uses for Bituminous Coal Co-Production Reference Plant

SCULLY CAPITAL

SOURCE AND USES OF FUNDS ($000)

PROJECT: Coal Gasification with Co-Production Plant Study

Bituminous Coal Co-Production Reference Plant

	Reference Case: 30,000 bpd blant w/ Bituminous coal	Reference Case: 30,000 bpd blant w/ Bituminous coal and CC&C
USES		
Facility Costs		
Solids Handling	$ 166,616	$ 166,616
Air Separation Unit	261,673	261,673
Gasification	470,533	470,533
F-T Liquids Area + Refining	369,650	369,650
Power Block	296,650	296,650
Gas Cleanup/Polishing	300,197	300,197
Carbon Sequestration Equipment		
- Compression	-	54,561
- Transportation, Storage, and Monitoring	-	-
Balance of Plant	352,601	352,601
Owner's Contingency	110,896	113,624
License Fees & Startup Costs	92,209	92,209
Design Costs	190,891	190,891
Subtotal - Facility Costs	2,611,915	2,669,204
Financing Costs		
Development Costs	54,248	55,583
Closing Costs	50,000	50,000
Debt Service Reserve Fund	129,840	132,639
Capitalized Interest	423,059	432,101
Subtotal - Financing Costs	657,147	670,323
Gross Funding Requirements	**$ 3,269,062**	**$ 3,339,527**
SOURCES		
Equity	$ 980,719	$ 1,001,858
Equity %	30%	30%
Debt	2,288,343	2,337,669
Debt %	70%	70%
Total Funds Drawn	**$ 3,269,062**	**$ 3,339,527**

2. Sources and Uses for Lignite-Based Reference Plant

Exhibit 3.8 presents the sources and uses statement for the lignite Reference Plant. The increased EPC cost for lignite plants results in a 10 percent higher “all-in” cost for the lignite Reference Plant. The total financed cost is $3.61 billion for the CC case and $3.68 billion for the CC&C case. As with the bituminous case, the capital cost of the CC&C case reflects the marginal cost of the compression unit.

Exhibit 3.8: Sources and Uses for the Lignite Co-Production Reference Plant

SCULLY CAPITAL

SOURCE AND USES OF FUNDS ($000)

Lignite Co-Production Reference Plant

	Reference Case: 30,000 bpd blant w/ Lignite coal	Reference Case: 30,000 bpd blant w/ Lignite coal and CC&C
USES		
Facility Costs		
Solids Handling	$ 268,071	$ 268,071
Air Separation Unit	193,395	193,395
Gasification	627,377	627,377
F-T Liquids Area + Refining	362,720	362,720
Power Block	274,480	274,480
Gas Cleanup/Polishing	341,613	341,613
Carbon Sequestration Equipment		
- Compression	-	57,750
- Transportation, Storage, and Monitoring	-	-
Balance of Plant	402,450	402,450
Owner's Contingency	123,505	126,393
License Fees & Startup Costs	83,290	83,290
Design Costs	212,345	212,345
Subtotal - Facility Costs	2,889,247	2,949,884
Financing Costs		
Development Costs	60,416	61,829
Closing Costs	50,000	50,000
Debt Service Reserve Fund	143,374	146,336
Capitalized Interest	466,761	476,332
Subtotal - Financing Costs	720,551	734,497
Gross Funding Requirements	**$ 3,609,797**	**$ 3,684,381**
SOURCES		
Equity	$ 1,082,939	$ 1,105,314
Equity %	30%	30%
Debt	2,526,858	2,579,066
Debt %	70%	70%
Total Funds Drawn	**$ 3,609,797**	**$ 3,684,381**

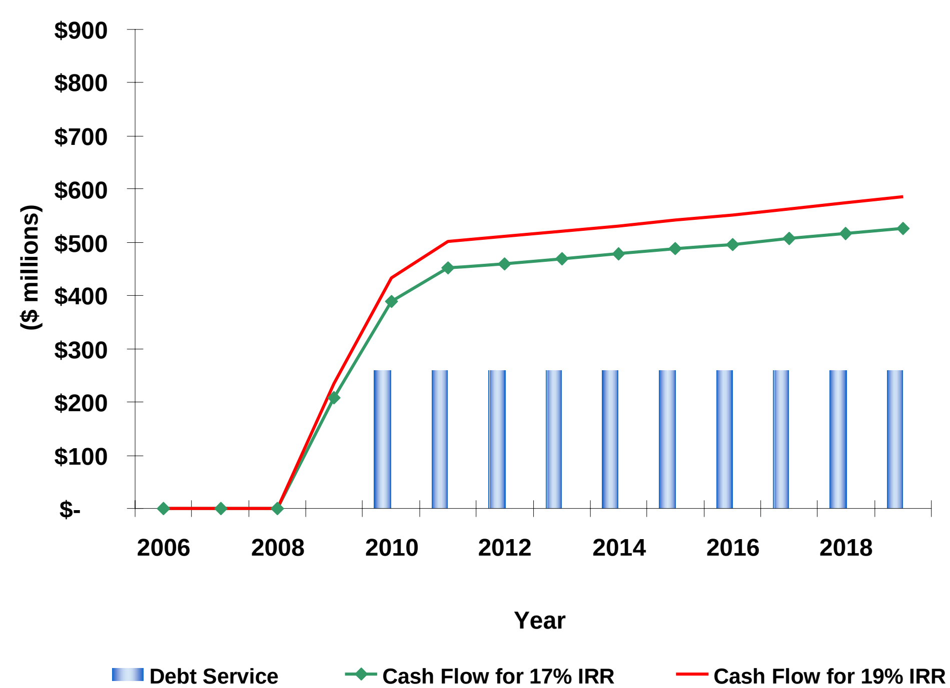
C. Reference Plant Results for Bituminous Coal and Lignite Co-Production Plants

This section provides the results of the analysis in terms of price per barrel of FT diesel fuel, the likely crude-equivalent price, and plants' debt service coverage performance. The term "cash flow" in this section refers to earnings before the effects of interest, depreciation, and taxes, commonly referred to as "EBITDA" (Earnings Before Interest, Taxes, Depreciation, and Amortization).

1. Results for Bituminous Coal Co-Production Reference Plant

Exhibit 3.9 presents the debt service and cash flow performance graph and associated metrics for the bituminous coal Reference Plant with CC. This exhibit shows that the price of FT diesel at 19 percent IRR for a bituminous coal Reference Plant with CC is $72.83 per barrel, a price approximately equivalent to a crude price (CEP) of $56.02 per barrel. In light of the uncertainty associated with values for technical and financing inputs (+/- 30 percent), FT diesel pricing could range from $56 to $95 per barrel, or from $43 to $73 per barrel on a crude-equivalent basis.

Exhibit 3.9: Results for Bituminous Coal Co-Production Reference Plant with CC



	19% IRR Scenario	17% IRR Scenario
Price of FT Diesel Per Barrel	$ 72.83	$ 67.18
Crude-Equivalent Price Per Barrel	$ 56.02	$ 51.68
Minimum Debt Service Coverage Ratio	1.67x	1.5x
Average Debt Service Coverage Ratio	2.16x	1.94x

An analysis of revenue composition of the plant shows that approximately 70 percent of the plant's revenue comes from the sale of FT diesel, 14 percent each from electricity and naphtha sales, and the balance from the sale of sulfur. (If a CC&C configuration is assumed, then the weight of FT diesel increases in the revenue mix at the expense of electricity sales.)

If the target IRR decreases to 17 percent, the price of FT diesel decreases to $67.18 (CEP: $51.68) per barrel, a decrease of $2.83 per barrel for every one percent in IRR. In the 19 percent target IRR case, the minimum Debt Service Coverage Ratio (DSCR) is 1.67. DSCR decreases to 1.5x for the 17 percent IRR scenario, implying that debt investors may perceive a decrease in credit quality associated with cash flows in this scenario. In this case, debt investors may ask for increased equity participation (which would, in turn, decrease the IRR) or require higher output pricing.

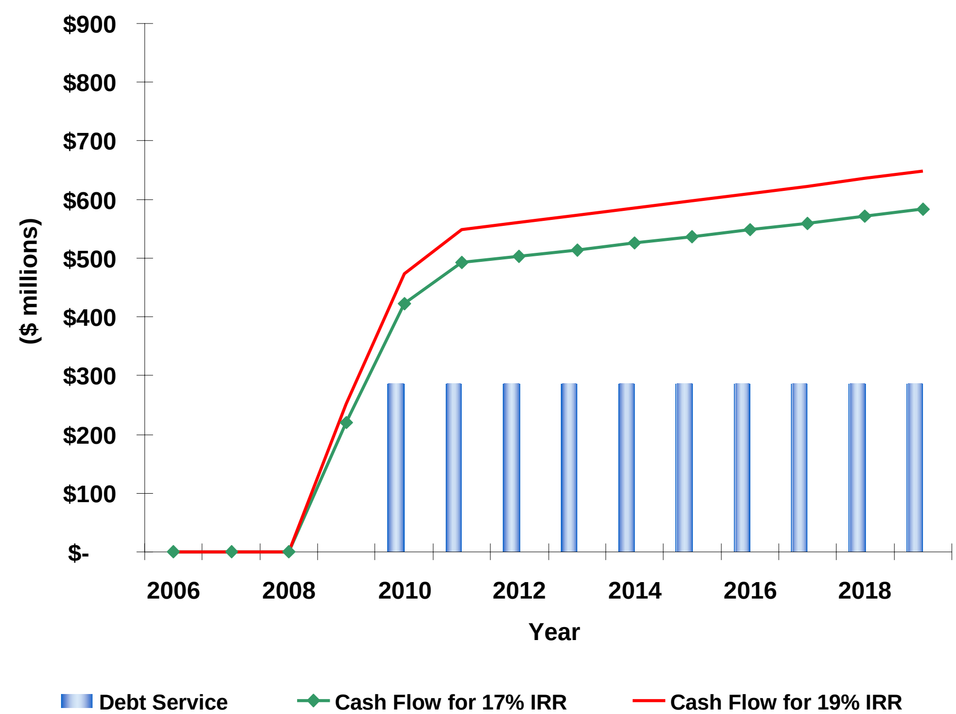
If CC&C is incorporated into the analysis, the price of FT diesel per barrel at a target IRR of 19 percent would rise slightly to $76.68 (CEP: $58.98) per barrel. At a 17 percent target IRR, the price would be $71.06 (CEP: $54.66) per barrel. The results obtained for the CC&C case must be considered in light of the assumption that the marginal cost of CC&C is the capital and operating cost of compression. (The cost of capturing carbon dioxide has been incorporated in the capital and operating costs associated with the gasifiers and FT reactors.)

2. <u>Results for Lignite Co-Production Reference Plant</u>

Exhibit 3.10 presents the debt service and cash flow performance graph and associated metrics for the lignite co-production Reference Plant with CC. This exhibit demonstrates that the price of FT diesel at 19 percent IRR for a lignite-based co-production Reference Plant with CC is $76.00 (CEP: $58.46) per barrel, higher than the bituminous coal-based co-production Reference Plant case by $3.17 (CEP: $2.44) per barrel. The revenue composition for the lignite co-production plant changes because the net output of electricity from the plant decreases. In this case, FT diesel sales contribute approximately 75 percent of the revenue, followed by naphtha at 14 percent, a decreased amount of electricity at 8 percent, and the balance from sulfur sales. If the target IRR decreases to 17 percent, the price of FT diesel decreases to $69.66 (CEP: $53.58) per barrel. As in the bituminous case, the DSCR at 17 percent IRR falls below 1.5x, creating the possibility that debt investors may perceive a decrease in credit quality associated with cash flows in this scenario. In this case, they may ask for increased equity participation (which would decrease the IRR) or require higher FT prices.

When CC&C is taken into consideration, the price of FT diesel per barrel at a target IRR of 19 percent is $79.83 (CEP: $61.41) per barrel. With CC&C and a target IRR of 17 percent, the price per barrel declines to $73.36 (CEP: $56.43). Interestingly, the price of FT fuel with CC&C at a 17 percent IRR is lower than the price of FT fuel with CC at 19 percent IRR. This result implies that target IRR considerations may have a greater impact on final price and project structure than use of CC&C.

Exhibit 3.10: Results for Lignite Co-Production Reference Plant with CC



	19% IRR Scenario	17% IRR Scenario
Price of FT Diesel Per Barrel	$ 76.00	$ 69.66
Crude-Equivalent Price Per Barrel	$ 58.46	$ 53.58
Minimum Debt Service Coverage Ratio	1.65x	1.48x
Average Debt Service Coverage Ratio	2.16x	1.94x

D. Sensitivity Testing on Key Inputs

Scully Capital conducted sensitivity testing to determine the impact on financial results of changes in several variables. Chapter 4 presents the results of the analysis of the prospects for an Alternative Plant configured to produce more electric power at the expense of FT fuel production compared to the Reference Plants and provides the results of sensitivity testing on this alternative configuration. Scully Capital performed the following sensitivity analyses:

- EPC costs: Changed by +/- 25 percent;
- Input coal prices: Changed by +/- 33 percent;
- Interest rates: Changed by +/- 200 basis points ("bps");

- Output electricity prices: Changed by +/- 15 percent;
- Construction time: Decreased by 6 months and increased by 12 months;
- Debt amortization periods: Changed by +/- 5 years;
- Final availability of plant: Changed by +/- 5 percent;
- Naphtha percentage: Reduced to 15 percent of total FT-equivalent output;
- Naphtha pricing: Increased naphtha pricing by 100 percent;
- Capital structure: Changed debt in D/E ratio by +/- 10 percent;
- Ramp-up schedule: Accelerated to 75 percent (from 51 percent), 85 percent (from 81 percent), and 90 percent (same);
- Target IRR: Changed to 17 percent (same) and 21 percent (from 19 percent); and
- Sale of carbon dioxide for enhanced oil recovery.

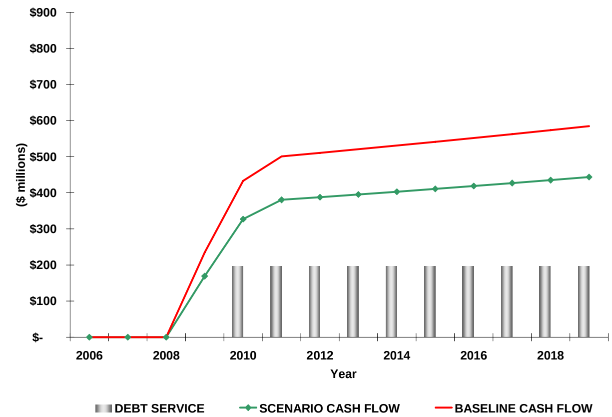
Scully Capital conducted these sensitivity analyses on the 19 percent target IRR case for the Reference Plant with CC that uses bituminous coal. (The sensitivities do not alter materially with different Reference Plant configurations, so running the same set of sensitivities on a lignite plant would not provide added value.) Scenario cash flows (shown as the green line with diamond dots in accompanying exhibits) change during sensitivity testing, while base case cash flows (red line) stay constant, providing a graphical representation of the change in cash flow needed to achieve 19 percent IRR and maintain adequate debt coverage. Each of these cases is analyzed on the pages that follow.

EPC Costs

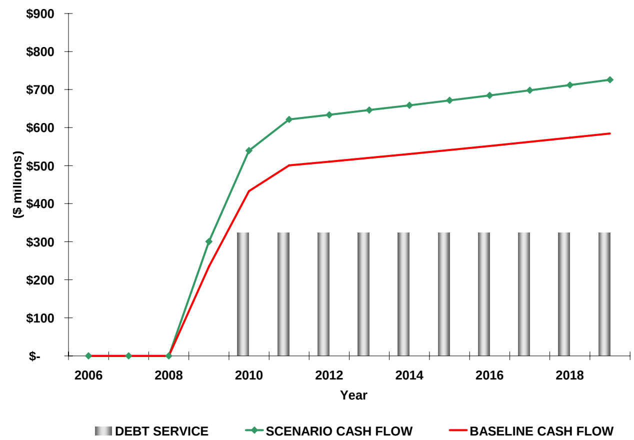
Given the uncertainty associated with cost assumptions for plants of this type, EPC costs were increased to $2.7 billion and decreased to $1.6 billion from the base of $2.17 billion. Exhibit 3.11 presents the results of this case, which tests the outer and inner bound of the anticipated range.

Exhibit 3.11: Cash Flow Changes Needed for Changes in EPC Cost

Increase in EPC by 25%		
FT Diesel Price	Crude-Equivalent Price	Percentage Change from Reference Case
$ 86.48	$ 66.52	18.7%



Decrease in EPC by 25%		
FT Diesel Price	Crude-Equivalent Price	Percentage Change from Reference Case
$ 59.20	$ 45.54	-18.7%



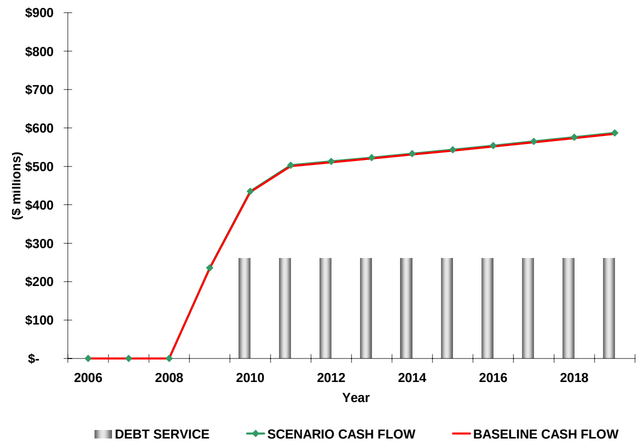
The analysis shows that, for a 25 percent change in EPC cost, the price of FT diesel changes approximately 19 percent. Thus, changes in EPC cost cause a linear change in the price of FT diesel.

Input Coal Prices

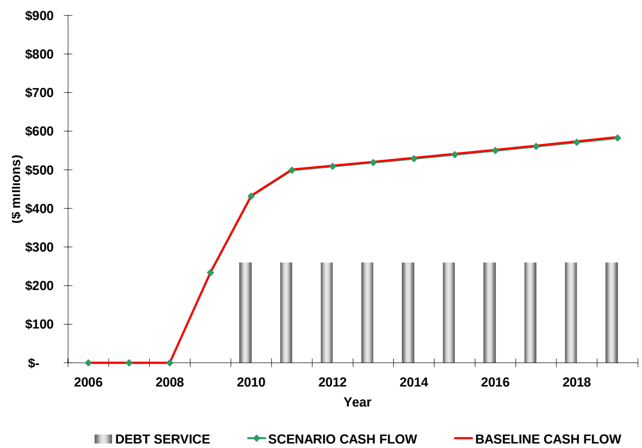
The input coal price was increased to $48 per short ton ($2.03/MMBTU) and decreased to $24 per short ton ($1.02/MMBTU) from the base price of $36 per short ton ($1.53/MMBTU). A price increase could arise, for example, from greater demand for coal (such as if an FT industry grows or an anticipated expansion of nuclear power does not materialize) or from rising coal transportation costs. A lower price could arise from a favorable long-term contract, decreased transportation costs to deliver the coal, or state incentives. Exhibit 3.12 presents the results of this analysis.

Exhibit 3.12: Cash Flow Changes Needed for Changes in Coal Costs

Increase in Coal Costs by 33%		
FT Diesel Price	Crude-Equivalent Price	Percentage Change from Reference Case
$ 81.93	$ 63.02	12.5%



Decrease in Coal Costs by 33%		
FT Diesel Price	Crude-Equivalent Price	Percentage Change from Reference Case
$ 63.76	$ 49.05	-12.5%



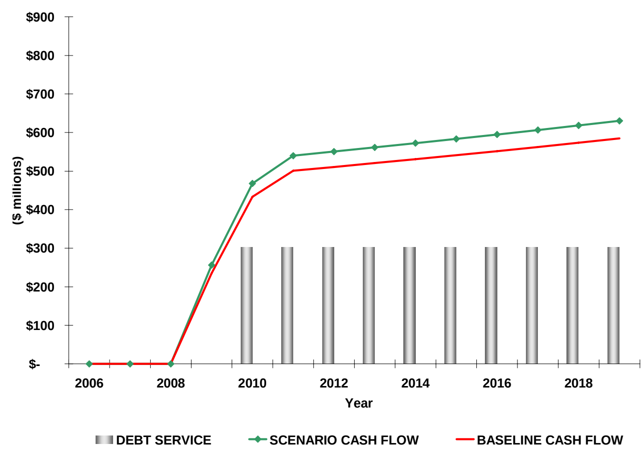
The analysis shows that the price of FT diesel changes by approximately 12 percent if the cost of coal varies by 33 percent. Thus, even though coal represents over 50 percent of the operating cost of plant, the pricing of FT liquids is more sensitive to changes in capital cost than operating cost. It is important to note that, because coal is a variable cost, the operating cash flow necessary to achieve a 19 percent IRR does not change significantly from the Reference Plant. Revenue required responds proportionally to variations in coal cost and, in turn, offsets changes in operating cost.

Interest Rates

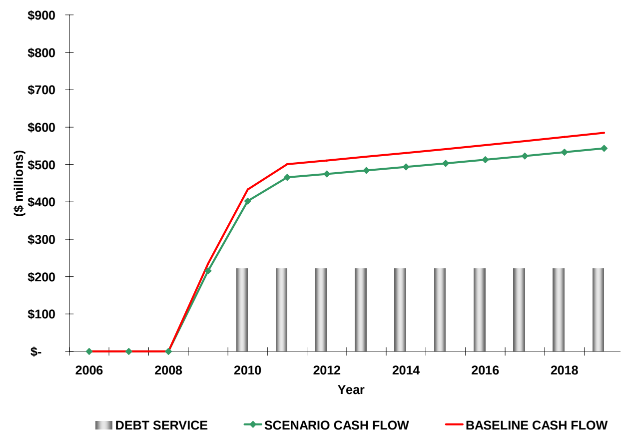
Interest rates were increased to 10 percent and decreased to 6 percent from the base case rate of 8 percent. The 2 percent (200 bps) change in interest rates represents a 25 percent change from the Reference Plant. An increased interest expense could result from an increasing interest rate environment. A lower interest rate could result from the use of credit incentives, from the use of on-balance-sheet financing, from an increase in creditworthiness, and/or from improved terms in sales contracts for plant outputs. Exhibit 3.13 presents the results from changes in interest rates.

Exhibit 3.13: Cash Flow Changes Needed for Changes in Interest Rates

Increase in Interest Rates by 200 bps		
FT Diesel Price	Crude-Equivalent Price	Percentage Change from Reference Case
$ 77.25	$ 59.42	6.1%



Decrease in Interest Rates by 200 bps		
FT Diesel Price	Crude-Equivalent Price	Percentage Change from Reference Case
$ 68.83	$ 52.95	-5.5%



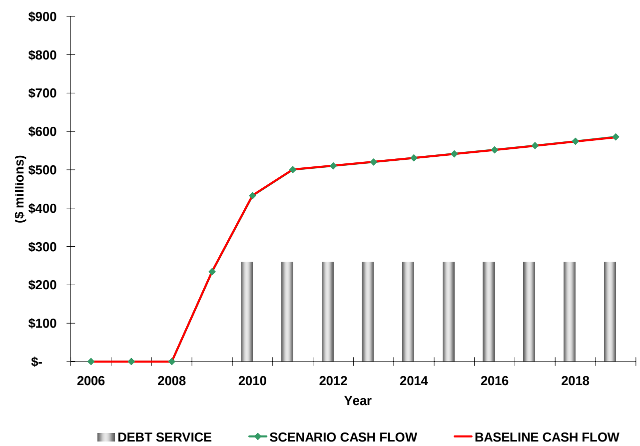
This analysis shows that a 25 percent change in interest rates changes the price of FT diesel by approximately 5.5 percent to 6 percent. The asymmetry of this change is due to the nature of mortgage-style payments in which the payment per year is kept constant but principal payments and interest payments vary. A lower interest rate allows for lower capitalized interest and a smaller debt service reserve fund. From this analysis, it appears that, on a percentage basis, coal and EPC costs have a greater effect on FT diesel pricing than interest rates.

Electricity Prices

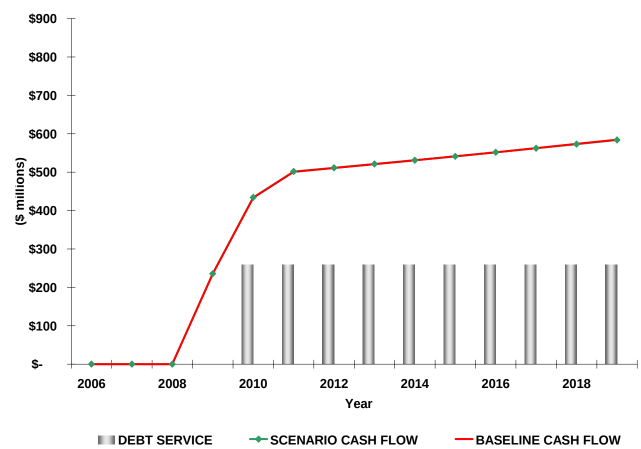
Electricity prices were decreased to $49.79/MWh and increased to $67.37/MWh from the base case rate of $58.58/MWh. The $8.79/MWh difference in electricity prices represents a 15 percent change from the base case. An increased price could result from regional factors, a favorable long-term contract, or changes in regulation. A lower price could result, for example, from increased competition under a deregulated setting. Exhibit 3.14 presents the results of this analysis.

Exhibit 3.14: Cash Flow Changes Needed for Changes in Electricity Prices

Increase in Electricity Price by 15%		
FT Diesel Price	Crude-Equivalent Price	Percentage Change from Reference Case
$ 70.80	$ 54.46	-2.8%



Decrease in Electricity Price by 15%		
FT Diesel Price	Crude-Equivalent Price	Percentage Change from Reference Case
$ 74.88	$ 57.60	2.8%



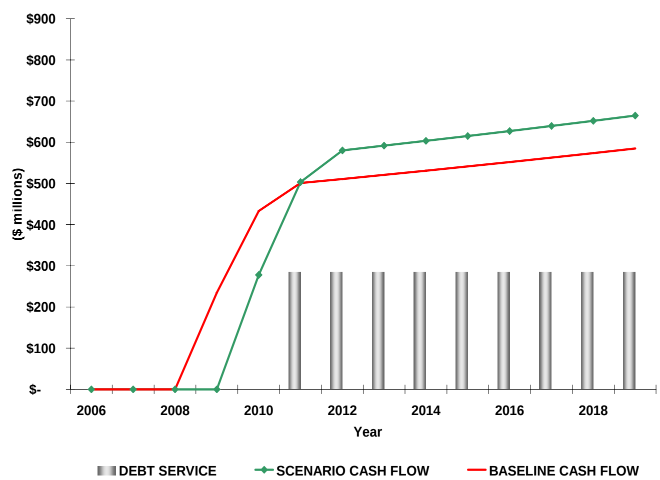
This analysis shows that a 15 percent change in electricity prices would result in an approximately 2.8 percent change in the price of FT diesel produced in Reference Plants. A higher electricity price would generate additional revenue from the base case, which could then be used to offset the price of FT diesel, keeping IRR constant. As is the case in coal price sensitivity testing, operating cash flow does not materially change as increased revenue from electricity sales offsets decreased revenue from FT diesel. Hence, the scenario cash flow curve is not altered significantly. These analyses show that, on a percentage basis, coal, EPC costs, and interest rates appear to have a greater effect on FT diesel pricing than electricity prices.

Construction Time

Two scenarios examine the effect of varying construction time from the base case estimate of 3 years. In the first scenario, construction time increases by 12 months to 4 years. In the second scenario, the construction time decreases by 6 months to 2.5 years. A 12-month delay represents a 33 percent change from the base construction time, while an acceleration of six months represents a 16.67 percent change. In the accelerated scenario, debt repayment occurs in the same time frame as in the Reference Plant (after a year of interest capitalization during the ramp-up period), and with the same 6-month interest-only period. For the scenario with an increased construction time, all project costs are expended in the 3-year time frame and an extra year of interest capitalization is added; debt amortization is delayed by a year.

Exhibit 3.15: Cash Flow Changes Needed for Changes in Construction Time

Construction Period at 4 Years		
FT Diesel Price	Crude-Equivalent Price	Percentage Change from Reference Case
$ 82.28	$ 63.29	13.0%



Construction Period at 2.5 Years		
FT Diesel Price	Crude-Equivalent Price	Percentage Change from Reference Case
$ 67.12	$ 51.63	-7.8%

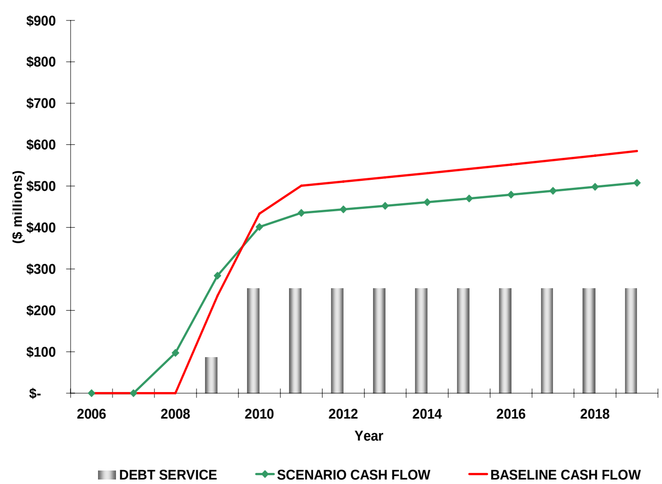


Exhibit 3.15 presents the results of this analysis. This analysis demonstrates that construction time can have a dramatic effect on the price of FT fuel. A one-year delay

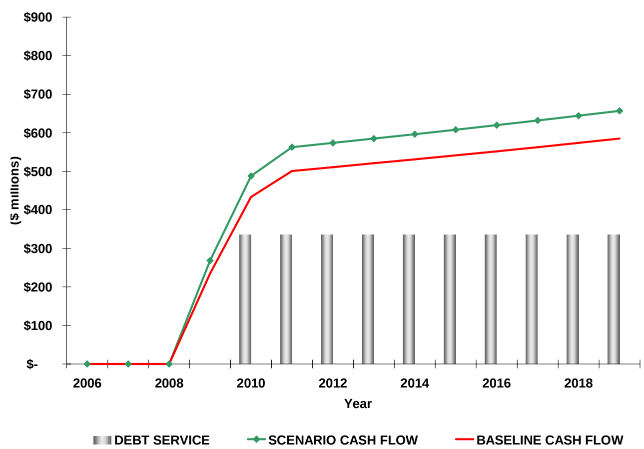
increases the price of FT diesel by 13 percent, while a six-month acceleration of construction decreases the price of FT diesel 7.8 percent. It appears that the non-linear relationship between schedule and price arises from the effect of compounding interest. The analysis does not consider any additional costs associated with the possible financing required for a construction delay.

Debt Amortization Periods

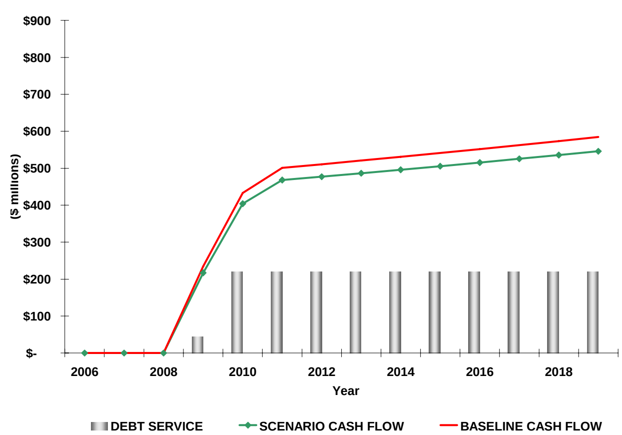
Two scenarios were examined in which the debt amortization period varies by +/- five years from the base amortization period of 15 years. In one scenario, the debt amortization period decreases to 10 years, while in the second, it increases to 20 years. The five-year change in amortization time frame represents a 33 percent change from the Reference Plant. The term of the debt is influenced by the capital intensity of the project and the length of the long-term contract to buy the FT diesel. Exhibit 3.16 compares the results of this analysis with those of the base case.

Exhibit 3.16: Cash Flow Changes Needed for Changes in Amortization

Debt Term at 10 Years		
FT Diesel Price	Crude-Equivalent Price	Percentage Change from Reference Case
$ 79.80	$ 61.38	9.6%



Debt Term at 20 Years		
FT Diesel Price	Crude-Equivalent Price	Percentage Change from Reference Case
$ 69.10	$ 53.15	-5.1%



The analysis shows that a change in debt tenor from 15 years in the base case yields an asymmetric change in the price of FT fuel. The price increases 9.6 percent from a five-year reduction in the amortization period, but decreases only 5.16 percent if the amortization term increases five years. The shorter the period of debt repayment, the greater the increase in price needed to achieve the target IRR. This outcome traces to the fact that more of the cash flow in early years is used to service debt rather than to provide a return to equity holders. It is important to note that the final maturity date of the debt is likely to be directly influenced by the length of the off-take agreement of the FT fuel. The scenarios show that project developers and investors can use the length of the debt term to balance the risk of being locked into a long-term contract and the price of fuel.

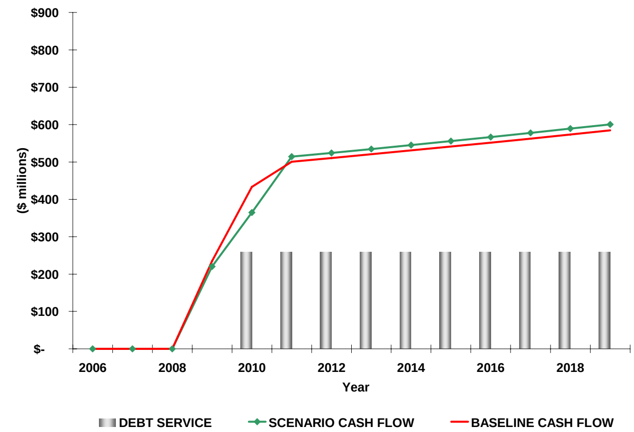
Final Availability of Plant

The final availability of the plant was decreased to 85 percent and increased to 95 percent from the base case of 90 percent. The 5 percent change in final availability represents a 5.56 percent change in average availability from the Reference Plant over the life of the plant. In the 85 percent final availability scenario, Scully Capital assumed a three-year ramp-up of 45 percent, 65 percent, and 85 percent (versus 51 percent, 81 percent, and 90 percent in the base case). For the 95 percent final availability, Scully Capital assumed a three-year ramp-up of 60 percent, 85 percent, and 95 percent.

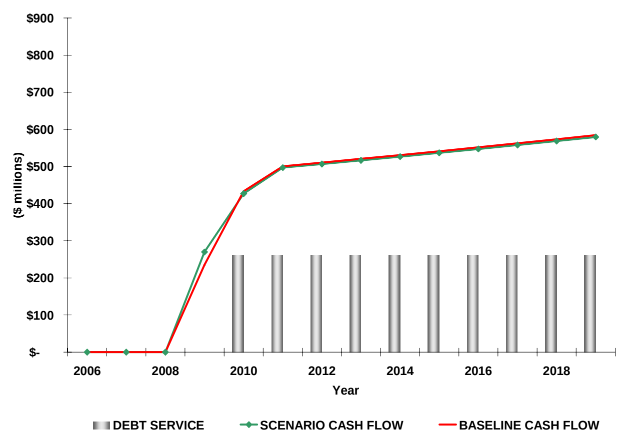
Exhibit 3.17 presents the analysis of the effect of final availability on plant economics. The exhibit shows that, even small changes in availability have a large effect on the price of FT fuel. For a 5.56 percent decrease in final availability, the change in price for FT fuel is about 8 percent, while the same increase in availability decreases the price by about 5 percent. On a percentage basis, changes in availability have an even greater effect than changes in EPC cost. Thus, the final price of FT fuel will be highly dependent on the technical maturity of a co-production plant.

Exhibit 3.17: Cash Flow Changes Needed for Changes in Availability

Final Availability at 85%		
FT Diesel Price	Crude-Equivalent Price	Percentage Change from Reference Case
$ 78.35	$ 60.27	7.6%



Final Availability at 95%		
FT Diesel Price	Crude-Equivalent Price	Percentage Change from Reference Case
$ 68.90	$ 53.00	-5.4%



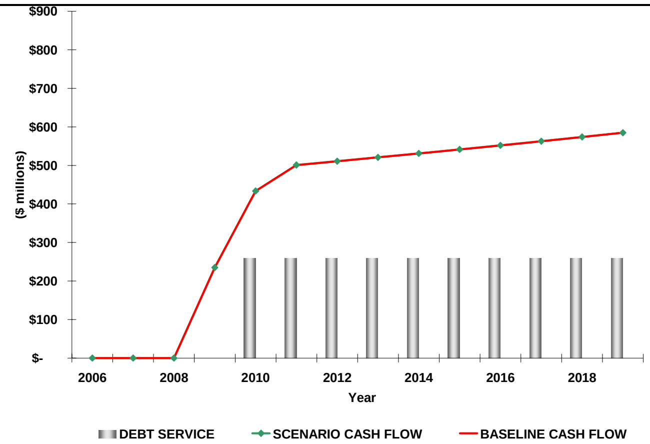
Naphtha Percentage

Recent changes in FT reactor technology may make it possible to reduce the percentage of the energy output in naphtha to 15 percent from the Reference Plant's 25 percent. To evaluate the significance of such a reduction, Scully Capital performed a sensitivity analysis that tests this change. If the plant ran at 100 percent availability, it would produce 27,627 barrels per day of FT diesel and 6,824 barrels per day of naphtha versus the Reference Plant output mix of 24,359 barrels per day of FT diesel and 11,398 barrels per day of naphtha.

Exhibit 3.18 presents the results of this analysis. Most significantly, reducing the naphtha percentage in the FT reactor output by 10 percent decreases the price of FT diesel by 5 percent, assuming that the smaller naphtha FT reactor is priced similarly to the one in the Reference Plant and there are no significant changes in operating cost.

Exhibit 3.18: Cash Flow Changes Needed for Change in Naphtha Output

Decrease Naphtha Output to 15% of Output		
FT Diesel Price	Crude-Equivalent Price	Percentage Change from Reference Case
$ 69.20	$ 53.23	-5.0%



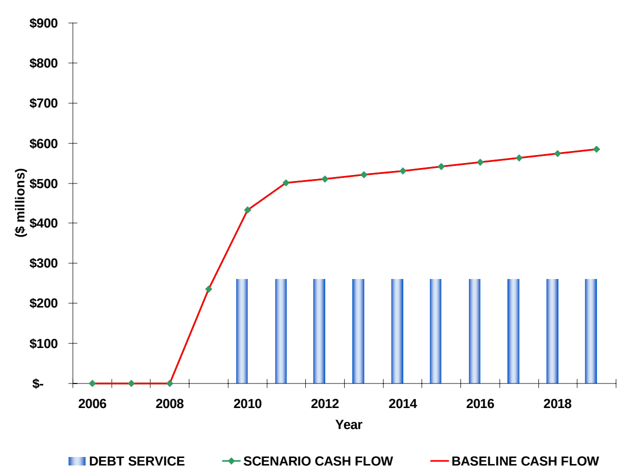
Naphtha Pricing

As noted earlier, the economics of co-production plants are likely to be site-specific. One of the economically significant outputs of the Reference Plant is naphtha. Pricing of naphtha can depend on the industries and power plants located nearby. In this scenario, the price of naphtha is increased to $60 per barrel from $30 per barrel, a 100 percent increase.

Exhibit 3.19 presents the results of this analysis. Increasing the price of naphtha by 100 percent would allow the price of FT diesel to decrease by 19.3 percent from the base scenario to $58.80 per barrel, or lower than the price of naphtha. While doubling the price of naphtha may not prove to be possible, this result does illustrate the impact of the pricing of a key co-product on the overall economics of a co-production project.

Exhibit 3.19: Cash Flow Changes Needed for Change in Naphtha Price

Increase Naphtha Price by 100% to $60/bbl		
FT Diesel Price	Crude-Equivalent Price	Percentage Change from Reference Case
$ 58.80	$ 45.23	-19.3%



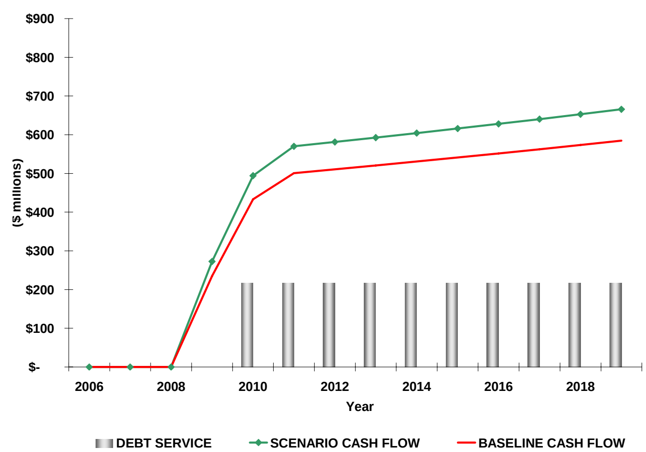
Debt Structure Change

This scenario examines the effect of financing leverage on the price of FT diesel. Scully Capital adjusted the base case debt/equity (D/E) ratio of 70:30, increasing it to 80:20 and decreasing it to 60:40. These changes represent a 14.29 percent change in debt percentage in the capital structure of a Reference Plant. For the 80:20 D/E structure, Scully Capital increased the debt service reserve fund to a one-year annual debt service because, while the average debt service coverage ratio was 1.5x, the initial years had a lower debt service coverage ratio. Scully Capital did not change the interest rate on the debt while changing the leverage. In this manner, the change in leverage can be understood without having to take into consideration fluctuations in interest rates.

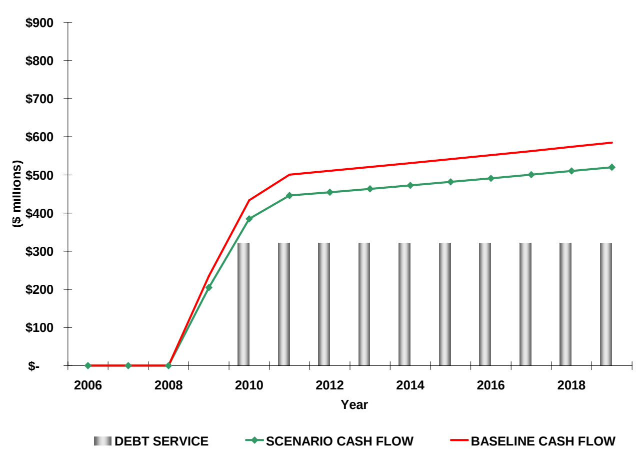
Exhibit 3.20 presents the results of the analysis of changes in debt structure. Changes in leverage produce a significant impact on the price of FT fuel. With a reduced D/E ratio of 60:40, the price of FT diesel increases 10.8 percent, while with an increased D/E ratio of 80:20, the price of FT diesel decreases by 8.6 percent.

Exhibit 3.20: Cash Flow Changes Needed for Changes in Debt

D/E Ratio at 60:40		
FT Diesel Price	Crude-Equivalent Price	Percentage Change from Reference Case
$ 80.66	$ 62.05	10.8%



D/E Ratio at 80:20		
FT Diesel Price	Crude-Equivalent Price	Percentage Change from Reference Case
$ 66.60	$ 51.23	-8.6%



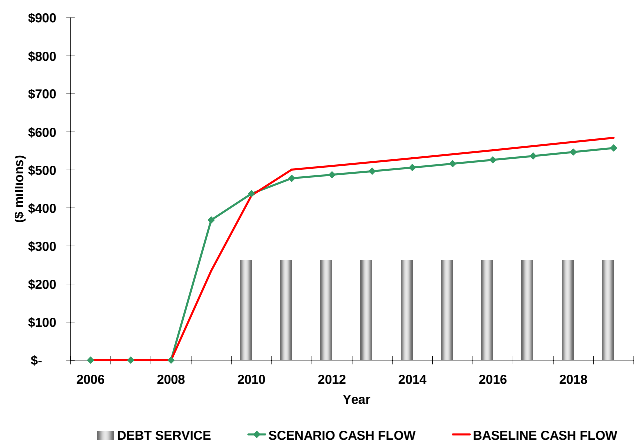
Ramp-Up Change

This sensitivity test measures the impact of changes in the ramp-up profile of the Reference Plant. Scully Capital changed the ramp-up profile of a plant to 75 percent, 85 percent, and 90 percent from the Reference Plant profile of 51 percent, 81 percent, and 90 percent, respectively.

Exhibit 3.21 presents the results of this analysis. Increasing the ramp-up profile of a co-production plant decreases the price of FT diesel by 3.6 percent from the base case. Faster ramp-up could help offset the cost associated with a longer construction period.

Exhibit 3.21: Cash Flow Changes Needed for Increase in Ramp-up

Ramp-up: 75%, 85%, and 90%		
FT Diesel Price	Crude-Equivalent Price	Percentage Change from Reference Case
$ 70.23	$ 54.02	-3.6%



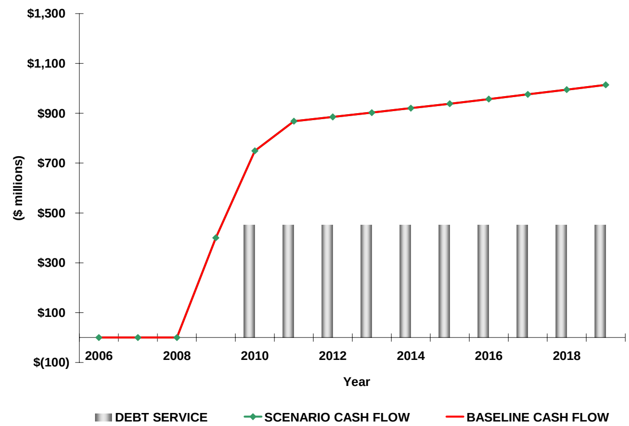
Plant Size

The effects of scaling have been debated extensively. Some industry experts believe large-scale plants (greater than 60,000 bpd) are required, while others believe that smaller and mid-size plants are also feasible. To provide insight into the impact of scaling on the price of FT fuel, Scully Capital modeled a 60,000 bpd bituminous coal plant and a 10,000 bpd bituminous coal plant. The total capital invested would be approximately $5.68 billion for the larger plant, which includes 12 gasifier trains and 12 FT reactor trains. The estimated investment for the smaller plant is $1.64 billion.

Exhibit 3.22 provides the results of this analysis. The graphs show that a cash flow greater than $1 billion per year is required to obtain 19 percent IRR for the larger plant, while $250 million in cash flow per year is required for the smaller plant. The price of FT diesel would be $69.06 (CEP: $53.12) per barrel for the larger plant, a difference of 5.2 percent compared with the mid-size bituminous coal plant. The difference is greater for the smaller plant: The price of FT diesel would be $99.89 (CEP: $76.84) per barrel, 37 percent higher than the Reference Plant price. The analysis shows that the effect of scaling is significant from 10,000 bpd plant to a 30,000 bpd plant and that the economies of scale do not increase proportionally as plants grow larger. The results of this analysis would be materially different if other engineering assumptions about scaling, design, and cost were made. Moreover, the benefits and costs of siting for differently sized plants may alter economics significantly.

Exhibit 3.22: Debt Service and Cash Flow for Bituminous Coal Co-Production Plants of Different Sizes

Larger Plant (60,000 bpd)		
FT Diesel Price	Crude-Equivalent Price	Percentage Change from Reference Case
$ 69.06	$ 53.12	-5.2%



Smaller Plant (10,000 bpd)		
FT Diesel Price	Crude-Equivalent Price	Percentage Change from Reference Case
$ 99.89	$ 76.84	37.2%

Enhanced Oil Recovery (EOR)

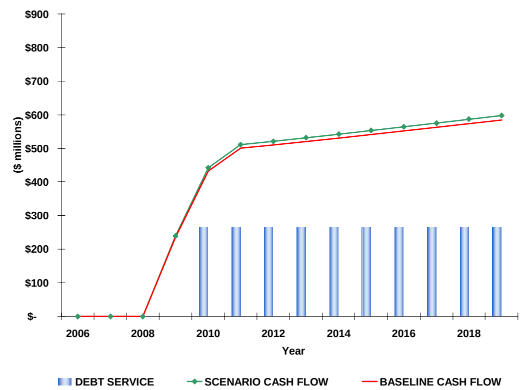
One potential opportunity for co-production plants is using captured carbon for EOR. In this sensitivity test, Scully Capital made the assumptions that carbon dioxide captured during gasifier operations can be sold for $12 per ton at the plant-gate[11] and at least 75 percent of the carbon dioxide produced can be captured and compressed. The tonnage

[11] As noted elsewhere in the report, industry sources suggest that the delivered price of carbon dioxide now ranges from $5 per ton to $12 per ton.

of carbon dioxide generated is assumed to be approximately equal to the coal input tonnage (as received). Exhibit 3.23 shows the effect of selling carbon dioxide for EOR.

Exhibit 3.23: Cash Flow Changes From Enhanced Oil Recovery

EOR Application at $12 per ton for CO_2		
FT Diesel Price	Crude-Equivalent Price	Percentage Change from Reference Case
$ 69.79	$ 53.68	-4.2%



This exhibit illustrates that, if 75 percent of the carbon dioxide produced in the plant could be captured, compressed, transported to an EOR site, and sold for $12 per ton, the revenue from carbon dioxide sales would be greater than the marginal cost of compression. In this scenario, the price of FT fuel needed to reach 19 percent IRR will be lower than in the Reference Plant analysis. At roughly $12 per ton for carbon dioxide, the price of FT fuel would be $69.79 (CEP: $53.68) per barrel. The ability to sell the carbon dioxide would depend on the location of the plant (i.e., proximity to an EOR operation and/or proximity to a carbon dioxide pipeline). Importantly, the benefits of EOR are tied to the cost assumptions relating to CC&C. If the capital and/or operating costs relating to CC&C are different, the benefits of EOR would change.

E. Summary

Scully Capital's analysis shows that a 32,502 bpd bituminous coal-based co-production Reference Plant with CC based on a design by Southern States Energy Board and Mitretek, which uses 17,987 tons of coal per day, produces FT diesel at a price of $72.83 per barrel. A variety of sensitivity tests on several input and other assumptions determined their effects on the pricing of FT diesel produced by the plant.

Exhibit 3.24 presents a summary of the results of sensitivity testing. All the variables tested have a material effect in the pricing of FT fuel from the Reference Plant. The price of FT diesel is most sensitive to EPC cost, IRR, capital structure, plant size, construction time, and debt amortization period. Further, the price of FT fuel is moderately sensitive to coal cost, naphtha price and output percentage, electricity price, and final availability. In addition, CC&C increases the price of FT diesel by 5.6 percent, but revenue from the sale of captured carbon dioxide for EOR may not only pay for the cost of compression, but also decrease the cost of FT diesel by 4.2 percent.

In general, the analysis of sensitivity testing results shows that changes to capital cost and capital structure have a greater effect on the price of FT fuel than changes in variable costs (e.g., coal) or in the price of an output with lower value than FT fuels (e.g., electricity). For example, sensitivity tests on EPC cost show that a one percent change in EPC cost causes a 0.8 percent change in FT fuel price. On other hand, the impact of changes in coal price on FT fuel price is less: A one percent change in coal price causes a 0.4 percent change in FT fuel price. The impact of capital cost is similar for a lignite co-production plant: The price of FT fuel from a lignite-based plant would be higher, despite the significantly lower price of lignite than bituminous coal.

Exhibit 3.24: Summary of Sensitivity Testing Results

		Increase		Decrease		
Sensitivity Test	**Input Value Change**	**Price of FT Diesel /bbl**	**Price in Crude-Equiv. /bbl**	**Price of FT Diesel /bbl**	**Price in Crude-Equiv. /bbl**	**Percentage Change from Reference Case**
Base Case: FT Diesel Value = $72.83, Crude-Equivalent Price = $56.02						
EPC Cost	+/- 25%	$ 86.48	$ 66.52	$ 59.20	$ 45.54	+/- 18.7%
Coal Cost	+/- 33%	81.93	63.02	63.76	49.05	+/- 12.5%
Interest Rates	+/- 200 bps	77.25	59.42	68.83	52.95	+ 6.1% / -5.5%
Price of Electricity Sold	+/- 15%	70.80	54.46	74.88	57.60	-/+ 2.8%
Construction Time	+ 1year / - 6 months	82.28	63.29	67.12	51.63	+ 13.0% / -7.8%
Debt Amortization Period	+/- 5 years	69.10	53.15	79.80	61.38	-5.1% / 9.6%
Final Availability	+/- 5%	68.90	53.00	78.35	60.27	-5.4% / 7.6%
Reduced Naphtha Output	15% of output	-	-	69.20	53.23	-5.0%
Higher Naphtha Price	+ 100%	58.80	45.23	-	-	-19.3%
Capital Structure (Debt Percentage)	+/- 10%	66.6	51.23	80.66	62.05	-8.6% / 10.8%
Faster Ramp-up	75%, 85%, and 90%	-	-	70.23	54.02	-3.6%
Plant Size	10,000 bpd/ 60,000bpd	99.89	76.84	69.06	53.12	+ 37.2% / -5.2%
Use of CO_2 for EOR	$12/ton CO_2	-	-	$ 69.79	$ 53.68	-4.2%

Sensitivity testing also provides a prelude to the effects of location and design analyzed in other tasks. A site location and plant design that benefit from lower coal prices, higher naphtha prices, a lower percentage of naphtha output, and (in the case of a plant with sequestration of carbon dioxide) a higher price for carbon dioxide could produce FT fuel at a significantly lower price than the Reference Plant.

IV. SUMMARY AND CONCLUSIONS

The country's vast supplies of coal have given rise to widespread consideration of co-production as an alternative source of some transportation fuel and a source of feedstocks for industrial processes. However, the history of both coal gasification and, especially, FT reactors in the United States is limited. Potential project sponsors have expressed uncertainty about their expectations for the long-term economic feasibility of such plants.

This study is aimed at determining the economics of and overall prospects for such plants within the range +/- 30 percent. The Reference Case financial modeling and sensitivity testing in Tasks I and II are the core of this analysis. A Reference Plant produces, as its main product, FT fuel. The study identifies the most important plant attributes driving the cost of this transportation fuel and determines the effect of a range of assumptions on the final price of FT fuel. The plant design is not based on a particular site and, as a result, the benefits and costs associated with a particular site are not considered. Given the multiple output nature of co-production, however, the effects of site selection could be significant and lead to material changes in product cost.

Several conclusions can be drawn from this analysis. These conclusions offer important insights into the necessary conditions for successful early commercial coal gasification with co-production projects.

Reference Plants that use bituminous coal appear to be economically feasible in that they may produce FT fuel at a price that is competitive in today's markets

The analysis suggests that FT fuel could be competitive with crude oil prices in the $56–$60 per barrel crude-equivalent range, not including the effect of any premium for low-sulfur fuel. Thus, at today's oil prices, FT fuel may offer both a hedge on future oil price increases and savings on the price of fuel. However, co-production plants face a variety of uncertainties that limit their ability to attract equity and debt investors, including consistent price volatility in energy markets, absent long-term contracts for sale of fuel they produce.

Plant cost information is limited, and capital costs are escalating

Vendors and technology companies are reluctant to share cost information and plant configuration data. Because these entities treat these data as confidential, information in the public domain regarding optimal configurations, project size, plant performance, and cost is limited and conflicting; available cost estimates are preliminary in nature and could vary by +/- 30 percent. In addition, over the two years since these cost estimates were developed, the engineering cost index and other measures of project cost indicate significant escalation (of as much as 135–175 percent) for capital-intensive projects.

Scully Capital talked to industry experts to obtain information about optimal plant configuration. Based on these conversations and analytical modeling, it appears that, in general:

- In lower-price electricity markets, electricity generated by a plant should be primarily used to operate other processes internal to the project, and net electricity output from the plant should be limited;
- For smaller plants, a thermal-only unit for electricity generation may be optimal;
- Spare gasifiers may not be required for mid-size and larger co-production plants; and
- A lower percentage of naphtha to total FT fuel output is generally preferable.

A mid-sized plant requires significant investment

A mid-size plant (30,000 bpd) will require a significant investment in the range of $3.3–$3.7 billion depending on the type of coal used and use of carbon capture and compression. For lignite-based plants, added coal handling and gasification equipment increase capital costs. Carbon compression equipment does not increase capital costs significantly, but operation of this equipment increases parasitic load, thus decreasing the net output of electricity available for sale.

Lower price of lignite does not appear to overcome increased capital costs

The lower price of lignite versus that of bituminous coal ($10/short ton vs. $36/short ton, respectively) decreases the operating cost of a plant, but this decrease is not sufficient to overcome the increased capital cost required for additional coal handling and gasification equipment. If the location of a plant offers other co-production possibilities, the economics of a plant that uses lignite may become more favorable.

Carbon Capture & Compression (CC&C) increases the price of FT fuel

Although all co-production plants are likely to separate carbon dioxide to gain process advantages, the addition of carbon compression increases the cost of FT fuel in the range of 5 percent (by $3.50–$4.00 per barrel, or $2.69–$3.08 per barrel on a crude-equivalent basis). The value to plant operations of capturing and compressing carbon dioxide in facilities that gasify coal compared to other coal technologies may play an important role in the construction of early commercial coal gasification plants.

Because the cost of separating the carbon dioxide from the synthesis gas is largely embedded in the capital cost of the plant, the cost of CC&C for the gasification and FT processes is the nominal cost of compression. In co-production plants, carbon dioxide is removed from synthesis gas after the gasification step and after the FT unit to improve plant performance. If capital and operating assumptions relating to CC&C

differ, the financial outcomes for compression would vary. This area of investigation is suitable for further analysis and technical input.

Plant location significantly impacts the value of co-products, affecting the economics of a plant

The ability to market co-products will depend on the location of the plant. For example, the ability to use carbon dioxide for EOR applications depends on the proximity of pipelines and suitable oil fields. If the carbon dioxide produced in a plant could be sold, the revenues could reduce the required cost of FT fuel beyond the cost to compress and transport the carbon dioxide (see Chapter 7). Similarly, the price garnered for electricity produced for sale in a plant affects the price that needs to be obtained for FT fuels. See Chapter 4 for the results of the Task III analysis of a high-power alternative configuration.

The location of a plant can also affect the pricing of outputs considered static in this analysis. For example, the price of naphtha can change if it is sold to an industrial source and the price of electricity depends on the region in which it is sold. Finally, location-specific costs related to site infrastructure can also affect plant economics and feasibility. These considerations would change the price of FT fuel required to achieve the target IRR.

Lack of construction contractor infrastructure and lack of standards for plant design impair financeability

The lack of standards and track records for fixed-price EPC contracts with performance guarantees and provisions for liquidated damages could impair the prospects of early commercial co-production projects, as bond holders may lack sufficient credit protection against downside risk. Performance wraps tend to be difficult to obtain for large capital projects with relatively unproven technology, such as gasification plants that produce FT fuels and electricity. Moreover, the recent interest in coal gasification — spurred by high energy prices, hedging against the possibility of future carbon controls, and in the United States, the investment tax credits in the Energy Policy Act of 2005 (EPACT 2005) — has created significant backlogs for EPC firms and gasification technology firms and intensified competition for limited design and construction capacity.

Scaling benefits are significant

The analysis projects a 37 percent difference in FT fuel price between small plants (10,000 bpd) and mid-sized Reference Plants (30,000 bpd), reflecting a substantial scaling benefit. The scaling benefit slows beyond this point, so a larger plant size (60,000 bpd) yields a smaller reduction in price (5 percent). As a result, it can be inferred that FT fuel price decreases initially with larger plant size. However, at a certain point, it appears that further decreases in the price of FT fuel arise more gradually as plant size increases.

Historic volatility in oil markets casts doubt on whether FT fuel would remain competitive over the long term, if subject to merchant risk

Although the price of FT fuels produced in a Reference Plant is likely to be competitive in today's energy markets, it is important to note that price volatility has been a constant factor over the past 30 years, and investors continue to be concerned about the impact of oil price fluctuations, particularly decreases, as reflected in the $40 per barrel floor price applied by credit rating agencies to new energy projects. If a plant were subject to merchant risk on a substantial portion of its output, it may not be able to survive swings in the crude oil market — or even be built.

Used in a risk-informed manner, incentives could "close the gap" that jeopardizes construction and operation of early commercial co-production projects

The analysis presents a number of scenarios and risk factors which should be studied singly and together, as well as on a site-specific basis, to better understand the best methods (and, if necessary, incentives) to decrease uncertainty in the development of co-production plants. Addressing the risk factors and economics through incentives applicable to specific risks and private-sector risk mitigation mechanisms could accelerate commercial deployment of coal gasification with co-production. Also, by matching incentives efficiently to key project risks, government could reduce its financial exposure for individual projects and increase the number of plants built with the same budget. See Chapter 6 for a discussion of the analysis of the impact and cost of a range of incentives for early commercial co-production facilities.

CHAPTER 4: ALTERNATIVE PLANTS AND SENSITIVITY TESTING

I. INTRODUCTION

A. Objectives and Approach

This chapter provides the results of analyses of the financial prospects of co-production Alternative Plants that produce increased net power and reports the results of sensitivity testing on several key project inputs and outputs. These analyses were performed during Task III of the study. Co-production plants can be configured in numerous ways to facilitate a desired product or revenue mix. Engineering designs and cost projections for only one alternative configuration were available: a plant that produces more electric power at the expense of FT fuel production. Other configurations, such as for plants optimized to produce fertilizer or chemical feedstocks, were not available. The high-power configuration is attractive for study, however. Because crude oil and natural gas markets experience price volatility, the production of greater amounts of electricity may introduce more stability into a project's revenue profile and, in turn, enhance creditworthiness.

As part of the Task III analysis, a third Reference Plant was developed for sub-bituminous coal. The analyses reported in this chapter, then, examine the Alternative Plant configuration, with and without carbon compression, for three types of coal: bituminous, sub-bituminous, and lignite. (Chapter 7 provides results of the analysis of the same Alternative Plants with the addition of sequestration of carbon dioxide produced in the plants.) This chapter also reports the results of an assessment of the impact of rising electricity prices and the determination of FT fuel price sensitivity to selected financing risks. Finally, it examines the effects of these variations on the price of FT fuel price required for the plant to attain a 19 percent internal rate of return (IRR).

Scully Capital developed hypothetical bituminous coal and lignite "Reference Plants" and documented them in Chapter 3 of this report. The Reference Plant analysis utilizes a non-recourse project financing structure that is appropriate for capital-intensive early commercial plants. Under this type of financing structure, a project "stands on its own" and its cash flows provide the underpinnings of creditworthiness. Conversations with project developers and financiers indicated that this type of structure would likely be utilized for the first few plants. Importantly, this type of structure insulates project sponsors from the full risk of the project, allowing risks to be shared by several participants in the project. The alternative bituminous coal plant with increased net power serves as the "Alternative Plant" in this chapter of the report. To accomplish the objectives of Task III, Scully Capital conducted five sub-tasks (see list in Chapter 1).

B. Chapter Organization

This chapter is organized into three sections:

- **Costs of Increased Electricity Production and Effects on Output FT Fuel Price:** This section discusses the technical and financial assumptions used to model the Alternative Plants and provides results displaying the effects of this alternative configuration on FT fuel price. An increase in electricity price over that of the Reference Plant was modeled to observe its effect on FT fuel price, and an analysis was conducted to test the minimum FT fuel price required to sustain debt coverage.
- **Sensitivity Analysis:** This section presents the results of applying relevant sensitivity testing to the Alternative Plants.
- **Summary and Conclusions:** This section summarizes the findings and draws inferences from the analysis useful in managing key risks and identifying barriers for early commercial co-production facilities with higher electricity output.

II. COSTS OF INCREASED ELECTRICITY PRODUCTION AND EFFECTS ON FT FUEL PRICE

This section presents the assumptions for analyses of a mid-sized (~30,000 bpd) bituminous coal co-production plant with an alternative configuration and the costs associated with increasing power production capability. This alternative configuration ("Alternative Plant") approximately doubles a plant's electricity production compared to the bituminous coal Reference Plant.

This section also presents the results of an analysis of the effect of variations in electricity price on FT fuel price, as well as a discussion of the minimum FT fuel price required for the plant to sustain debt coverage.

Part II is organized into the following sections:

- Plant Characteristics of Alternative Plant;
- Financing and Output Pricing Assumptions;
- Sources and Uses of Funds;
- Results of Analysis of Electricity Price;
- Minimum Coverage Analysis; and
- Summary.

A. Plant Characteristics of Alternative Plant

The Reference Plant discussed in Chapter 3 utilizes 12,987 tons of bituminous coal per day to generate 257 MWe of net electricity and 32,502 barrels per day of FT-equivalent fuel. The Alternative Plant configuration increases electricity production at the expense FT liquid outputs.

Exhibit 4.1 displays, for comparison purposes, the technical assumptions and results of the Reference Plant. The results indicate that the price of FT diesel under a long-term contract needs to be in the range of $73 per barrel, or a crude-equivalent price (CEP) of $56 per barrel, to achieve a target internal rate of return (IRR) of 19 percent. Under assumptions of lower IRRs (specifically, 17 percent and 15 percent), the required price falls to $67 (CEP: $52) per barrel and $62 (CEP: $47) per barrel, respectively. Importantly, debt service coverage declines with decreases in project IRR to the point that financing uncertainty becomes a significant issue. In interviews that were a part of this effort, financial experts agreed that an IRR of 17 percent to 19 percent reflects financial market conditions and expectations.

Exhibit 4.1: Overview of Configuration and Results for the Bituminous Coal Reference Plant

Input Characteristics	
Tons of Coal Per Day	17,987
BTU Value of Bituminous Coal	11,800
Price of Coal Delivered	$36 / Short Ton
Output Characteristics at Capacity	
FT Liquids (bpd)	
FT Diesel	24,359
Naphtha	11,398
Total: FT Diesel Equivalent	32,502
Electricity Production	
Gross (MWe)	725
Net (MWe)	257
Net (MWe) with Carbon Capture and Compression	205
Output Pricing	
At 19% IRR	
FT Diesel	$73/barrel
in Crude-Equivalent Price	$56/barrel
Naphtha	$30/barrel
Electricity	$58/MWh
Min. Pre-Tax Debt Service	1.67x
At 17% IRR	
FT Diesel	$67/barrel
in Crude-Equivalent Price	$52/barrel
Naphtha	$30/barrel
Electricity	$58/MWh
Min. Pre-Tax Debt Service Ratio	1.50x

As noted in Chapter 3, in order to determine the assumptions required for configuration of the Alternative Plant, Scully Capital utilized engineering data obtained from the Southern States Energy Board's (SSEB) American Energy Security Study ("AES Study"). Scully Capital utilized the AES Study's 30,001 barrel per day bituminous coal once-through configuration as the basis for the Alternative Plant.

Based upon analysis of data in the AES Study, Scully Capital determined that the Alternative Plant increases net power production to 590 MWe per day, or to approximately 130 percent of that of the Reference Plant. Fuel production levels decrease by approximately 8 percent to 30,001 barrels. Additional differences from the Reference Plant include an increase in required coal input, a decrease in carbon dioxide output from the FT unit and in the FT fuel, and an increased output of carbon dioxide from the power generation unit. Exhibit 4.2 summarizes these differing assumptions and additional technical assumptions for both the bituminous coal Reference Plant and the Alternative Plant.

Exhibit 4.2: Technical Assumptions for Alternative Plant

Type of Coal Co-Production Plant	Bituminous Coal Reference Plant	Alternate Plant with Sequestration	% Change from Reference Plant
Input Characteristics			
Tons of Coal Per Day	17,987	19,517	8%
BTU Value of Bituminous Coal	11,800	11,800	
Price of Coal Delivered	$36 / Short Ton	$36 / Short Ton	
Output Characteristics @ Capacity			
FT Liquids (bpd)			
FT Diesel	24,359	22,485	-8%
Naptha	11,398	10,521	-8%
Total: FT Diesel Equivalent	32,502	30,001	-8%
Electricity Production			
Gross (MWe)	725	1045	31%
Parasitic Load	468	455	-3%
Net (MWe)	257	590	56%
Carbon Dioxide Captured (in tons/day)			
Input Carbon			
Carbon Captured in Processing	6,763	7,083	5%
In Fuel	3,918	3,616	-8%
In Stack Gas	860	1,823	53%
	11,541	12,522	8%
Carbon Captured	6,763	7,083	5%
at 90% Availability	6,087	6,375	5%
at 80% Capture	4,869	5,100	5%
in CO_2 Terms	17,854	18,699	5%
Plant Characteristics			
Efficiency (HHV)	48%	47%	-2%
Gasifier Trains	6	7	
Spare Gasifier	No	No	
FT Reactors	6	6	
Other Characteristics			
Construction Time	3 Years	3 Years	
Availability			
1st Year	51%	51%	
2nd Year	81%	81%	
3rd+ Year	90%	90%	

A comparison of the bituminous coal-based Reference Plant to the Alternative Plant further reveals the following:

- The Alternative Plant configuration uses approximately 1,500 more tons of coal per day (19,517 - 17,987 = 1,530).
- The Alternative Plant produces 333 more MWe of net electricity than the Reference Plant.

- The Alternative Plant produces 2,501 (32,502 - 30,001 = 2,501) less barrels of FT fuel and naphtha than the Reference Plant.
- The Reference Plant, when equipped with carbon capture and compression (CC&C) capabilities (see discussion in Chapter 3), can capture 95 percent of the carbon contained in the input coal through carbon dioxide capture equipment associated with the gasifiers (Selexol units) and the FT synthesis process, not including carbon in FT fuels produced in the plant and stack gas in the power generation block. Based on the more conservative assumptions used in this analysis, the Reference Plant captures about 81 percent of the carbon, calculated on a comparable basis.[1] Because the Alternative Plant does not capture carbon dioxide in the power production stack gas, the percentage capture of the carbon in the input coal for this plant declines to 74 percent.[2]

B. Financing and Output Pricing Assumptions

The technical assumptions used in the analysis along with key capital and operating cost have been discussed earlier. This section discusses in greater detail financial assumptions used in the analysis, as well as price assumptions and methodology for the output products.

As in the Reference Plant analyses, Scully Capital modeled the Alternative Plant under a non-recourse project financing structure; the same financial assumptions and methodology were used in this analysis. The price of FT diesel resulting from both analyses equals the price of crude oil equivalent plus the cost of refining the product, not including distribution, marketing, or taxes.

C. Sources and Uses of Funds

Notable cost differences between the Alternative Plant and the Reference Plant are due in large part to the additional equipment required for increased electricity production. In particular, the greater power block cost in the Alternative Plant accounts for more than one-third of the cost differential. Smaller increases in the plant's remaining equipment and contingency costs account for the rest of the differential. Exhibit 4.3 summarizes the facility costs.

Facility costs for the Alternative Plant amount to $2.88 billion. As a result of the increased power configuration, construction costs are $272 million higher than those of the Reference Plant, an increase of nearly 10 percent.

Notably, however, the price of FT fuel for the Alternative Plant is lower than the price indicated for the Reference Plant by approximately 50 cents per barrel. The additional

1 Calculated conservatively, the carbon dioxide equipment has an effective capture rate of 80%. (80% * 6,763 + 3,918) / 11,541 = 81%.

2 (80% * 7,083 + 3,616) / 12,522 = 74%.

revenues generated from increased electricity sales exceed revenue reductions from the lower output of FT fuel and naphtha and the higher capital and operating costs associated with this plant. Although the price difference is very small relative to the FT fuel price, the Alternative Plant offers a more diversified revenue stream in comparison to the Reference Plant which, in turn, could provide a more stable cash flow profile.

Exhibit 4.3: Sources and Uses for Alternative Plant

SCULLY CAPITAL

SOURCE AND USES OF FUNDS ($000)

Alternative Plant with Increased Net Power

USES		**SOURCES**	
Facility Costs		**Gross Funding Requirements**	$ 3,602,636
Solids Handling & ASU	$ 459,055		
Gasification and FT	902,644		
Power Block + Gas Cleaning	721,014	Equity	1,080,791
Balance of Plant	372,164	Equity %	30%
Carbon Sequestration Equipment			
- Compression	-	Debt	2,521,845
- Transportation, Storage, and Monitoring	-	Debt %	70%
Owner's Contingency	122,744		
License Fees & Startup Costs	99,848		
Design Costs	206,213		
Subtotal - Facility Costs	2,883,681		
		Debt Composition	
Financing Costs			
		Tranche A	2,521,845
Development Costs	60,044		100%
Closing Costs	50,000		
Debt Service Reserve Fund	143,089		
Capitalized Interest	465,822		
Subtotal - Financing Costs	718,955		
Gross Funding Requirements	**$ 3,602,636**	**Total Funds Drawn**	**$ 3,602,636**
Price of FT Fuel (@19% IRR)	**$ 72.65**	**Minimum DSCR**	**1.69**
Crude-Equivalent Price	**$ 55.88**	**Average DSCR**	**2.15**

D. Results of Analysis of Electricity

To further analyze the potential of the Alternative Plant to offer a stronger credit profile, Scully Capital modeled a 20 percent increase in the Reference Plant electricity price to $70/MWh and observed the effect of the increase on the minimum FT fuel price required to attain a 19 percent IRR. Notably, the guaranteed sale of electricity at higher rates could provide the plant with an even greater cushion against lower-than-expected FT fuel prices. The analysis concluded that increasing the price of electricity by 20 percent from $59/MWh to $70/MWh causes the plant's minimum required price for FT fuel to decrease below the Reference Plant price by approximately $7 per barrel to a price of $66 (CEP: $51) per barrel. The lower FT fuel price could not only provide the Alternative Plant with a more competitive stance in the FT fuel market than the Reference Plant, but it would also lend greater resilience against risks associated with price volatility in fuel markets.

E. Minimum Coverage Analysis

In order to understand the degree of resilience that the Alternative Plant has against downturns in the oil market, Scully Capital analyzed the minimum FT fuel price required to maintain debt service obligations and provide a 19 percent IRR. This “break-even point” occurs when the model reaches a debt service coverage ratio of approximately 1.1x. Although this scenario would not be ideal from a profitability standpoint, it provides an idea of the plant’s ability to survive occasional downturns in the fuel market. Notably, as of November 2007, Standard & Poor’s (S&P) utilizes $40 per barrel as its long-term crude oil price assumption in performing credit analyses. This figure provides a conservative estimate for evaluating long-term creditworthiness of fuel providers; it will be used in this study as a basis to determine the long-term sustainability of a plant’s fuel production operations.

The results of this analysis, assuming an electricity price of $59/MWh, indicate that an FT fuel sales price of approximately $49 (CEP: $38) per barrel would still allow the Alternative Plant to support its debt payments with revenues generated by the plant. The results, assuming a higher electricity price of $70/MWh, indicate that an FT fuel sales price of $42 (CEP: $32) per barrel is required to sustain debt obligations. Since this range indicates that a plant may potentially be able to sustain operations in the event of oil prices falling well below S&P’s $40 per barrel long-term crude oil price assumption, investors could be provided with an additional level of comfort when considering the financeability of a plant.

F. Summary

A number of costs and benefits arise from altering the Reference Plant configuration to increase net power production. The most notable incremental costs of the increased power configuration are the requirements for a greater amount of coal, an additional gasifier, and greater coal handling capability. Other costs associated with the Alternative Plant include a revenue decrease from reducing the production of FT fuel and naphtha by approximately 2,500 barrels. Overall, the price of FT fuel required to attain 19 percent IRR is comparable for the Reference Plant and the Alternative Plant; the price differs only by the small margin of 50 cents (CEP: 38 cents) per barrel. It therefore appears that the increased power production of 333 MWh in the Alternative Plant roughly offsets, in economic terms, the plant’s decreased FT fuel and naphtha production. This greater percentage of energy production in the form of electricity, absent of any sizable affects on FT fuel price, offers plant owners the opportunity to benefit from a more diverse set of outputs, which insulates them more fully from price volatility in the oil markets.

As the analysis above illustrates, entering into long-term off-take agreements for electricity at a price of $70/MWh that is 20 percent above Reference Plant assumptions allows the FT fuel price to fall by more than $7 below the Reference Plant price while still allowing the project to reach a 19 percent IRR. Therefore, if the plant's owners enter into a long-term PPA for electricity at a price within the prevailing range of $59/MWh to $70/MWh, investors can expect a more robust financing scenario than that of the Reference Plant.

In addition, the analysis reveals that, even in the absence of increased electricity prices, the Alternative Plant is capable of servicing debt payments in the face of a decrease in FT fuel price to $49 (CEP: $38) per barrel. In a more optimistic scenario with the sale of electricity at $70/MWh, FT fuel prices may fall even lower to $42 (CEP: $32) per barrel while the plant continues to satisfy its debt obligations. Since the low end of this FT fuel price range falls well below S&P's assumption about long-term oil prices, these results indicate that the Alternative Plant will potentially be able to sustain operations over the long term under reasonable electricity pricing scenarios. The Alternative Plant therefore is a plant configuration that could better insulate itself from fuel market volatility and provide an enhanced level of creditworthiness compared to the Reference Plant.

III. SENSITIVITY ANALYSIS

The sensitivity test results reported in this section evaluate the impact of fluctuations in key inputs to the Alternative Plant. To facilitate comparison of the prospects of the Reference Plants and the Alternative Plants, Scully Capital analyzed many of the same sensitivities for both configurations. The analysis also included sensitivity tests similar to those in the Task V.B. evaluation of three Reference Plants with carbon dioxide sequestration, including some with EOR, and of the Alternative Plants with sequestration. Sensitivity test results for the Reference Plants with sequestration and the Alternative Plants with sequestration are discussed in Chapter 7. Scully Capital conducted the following sensitivity tests for Alternative Plants:

- Increase/Decrease in Plant Capital Costs;
- Increase/Decrease in the Price of Coal;
- Reduce Plant Naphtha-to-Diesel Production Ratio;
- Increase/Decrease in Interest Rates;
- Increase/Decrease in Plant Availability Rates;
- Acceleration/Delay in Construction Period; and

A. Increase/Decrease in Plant Capital Costs

Reflecting the considerable degree of uncertainty associated with cost assumptions for plants of this type, Scully Capital modeled a 25 percent increase and decrease in plant capital costs, the same range it used in sensitivity testing on the Reference Plants (see Chapter 3 for Reference Plant sensitivity testing results). The results of these sensitivity tests represent the upper and lower bounds for the range of anticipated FT fuel prices.

Exhibit 4.4 summarizes the results for each sensitivity test. The exhibit shows that the economics of the Alternative Plant appear to be highly sensitive to changes in capital costs. Specifically, a 25 percent increase/decrease in EPC costs equates to a nearly equivalent percentage change in FT fuel price, a linear relationship.

Exhibit 4.4: Increase and Decrease in EPC Costs for the Alternative Plant

FT Fuel Price Results ($ per barrel)	Alternative Plant	
	25% Change in EPC Costs	
	Increase	Decrease
FT Diesel Price	$89.90	$55.75
Crude-Equivalent Price	$69.15	$42.88
Change from Reference Plant	$17.25	-$16.90
% Change from Reference Plant	23.7%	-23.3%

B. Increase/Decrease in the Price of Coal

Scully Capital increased the price of bituminous coal to $48 per short ton ($2.04/MMBtu) and decreased the price to $24 per short ton ($1.02/MMBtu) from the base price of $36 per short ton ($1.53/MMBtu), the same range it used in sensitivity testing on the Reference Plants. An increase in the price of coal could arise, for example, from greater demand for coal (such as if an FT industry grows or an anticipated expansion of nuclear power does not materialize) or from rising transportation costs. A lower price could result, for example, from a favorable long-term contract, decreased coal transportation costs, or state incentives.

Changes in FT fuel price for the Alternative Plants display greater levels of sensitivity than those of the Reference Plant. This difference is attributable to the use of more coal in the Alternative Plants to generate increased electricity output. Exhibit 4.5 provides the results of the analysis of coal price changes.

Exhibit 4.5: Increase and Decrease in Price of Coal for the Alternative Plant

FT Fuel Price Results ($ per barrel)	Alternative Plant	
	33% Change in Coal Prices	
	Increase	Decrease
FT Diesel Price	$83.32	$61.95
Crude-Equivalent Price	$64.09	$47.65
Change from Reference Plant	$10.67	-$10.70
% Change from Reference Plant	14.7%	-14.7%

The analysis shows that a 33 percent change in the price of coal causes a change in the price of FT diesel of approximately 15 percent for the Alternative Plant. The additional quantities of coal required by the Alternative Plants made them more sensitive to coal price changes than the Reference Plant, for which a 33 percent change in the price of coal causes a 13 percent change in FT fuel price. This analysis also confirms the conclusion that coal price plays a greater role for the Alternative Plant in the determination of FT fuel price.

C. Reduce Plant Naphtha-to-Diesel Production Ratio

As noted in Chapter 3, recent innovations in FT reactor technology make it possible to reduce the percentage of naphtha fuel produced by co-production plants from 25 percent to 15 percent of total energy production. If this technology proves to be commercially successful, it will have positive financial implications because naphtha commands a significantly lower price in the marketplace than FT diesel. In other words, a plant would be more profitable if the naphtha it produces is a lower percentage of total fuel production.

If an Alternative Plant were to run at 100 percent availability, it would produce 25,501 barrels per day of FT diesel and 4,500 barrels per day of naphtha versus the Reference Plant mix of 22,501 barrels per day of FT diesel and 7,500 barrels per day of naphtha. Exhibit 4.6 displays the results of a decrease in the percentage of naphtha production from 25 percent to 15 percent of total energy output.

Exhibit 4.6: Decrease in Naphtha Production for the Alternative Plant

FT Fuel Price Results ($ per barrel)	Alternative Plant
	15% Naphtha Production
FT Diesel Price	$68.98
Crude-Equivalent Price	$53.06
Change from Reference Plant	-$3.67
% Change from Reference Plant	-5.1%

A reduction in naphtha production levels results in a decrease in the price for FT fuel of approximately 5 percent for the Alternative Plant. This result rests on the assumption that the cost of technology enabling these reductions and its associated operating costs are comparable to those of the Reference Plant.

D. Increase/Decrease in Interest Rates

As in the sensitivity testing for the Reference Plant, Scully Capital modeled a 25 percent change in the plant's interest rate by increasing and decreasing the Alternative Plant's interest rate to 10 percent and 6 percent, respectively, from the base case rate of 8 percent. An increased interest expense could result from an increasing interest rate environment or a reduction in the credit quality of the project. A lower interest rate could result from a decreasing interest rate environment, the use of credit incentives, from the use of on-balance-sheet financing, from improved terms in sales contracts for plant outputs, and/or from improvements in creditworthiness. Exhibit 4.7 presents the results of these changes in interest rates.

Exhibit 4.7: Increase and Decrease in Interest Rates for the Alternative Plant

FT Fuel Price Results ($ per barrel)	Alternative Plant	
	25% Change in Interest Rate	
	Increase	Decrease
FT Diesel Price	$77.92	$67.85
Crude-Equivalent Price	$59.94	$52.19
Change from Reference Plant	$5.27	-$4.80
% Change from Reference Plant	7.3%	-6.6%

The analysis shows that a 25 percent increase in interest rates causes FT fuel price to increase by approximately 7 percent for the Alternative Plant with Increased Net Power, while a 25 percent decrease reduces FT fuel price to decline by 6.6 percent, slightly more than the impact of higher and lower interest rates for the Reference Plant. The asymmetry of these changes is due to the nature of mortgage-style payments in which the payment per year is kept constant but principal payments and interest payments vary. A lower interest rate allows for lower capitalized interest and a smaller debt service reserve fund. These results indicate that interest rates can have a material affect on FT fuel prices.

E. Increase/Decrease in Plant Availability Rates

The final availability of the Alternative Plant was decreased to 85 percent and increased to 95 percent from the base case rate of 90 percent. This 5 percent change represents an average change in final availability of 5.56 percent over the life of the Alternative Plant; this change is the same as that used in the sensitivity analysis of the Reference Plant. Scully Capital also adjusted the three-year ramp-up period for operations at a new plant. For the scenario with an increase in availability, the three-year ramp-up increases to 60 percent in year one, 85 percent in year two, and 95 percent in year three. In the decreased availability scenario, the ramp-up incorporates 45 percent availability for the first year, 65 percent for the second year, and 85 percent for the third year. Exhibit 4.8 presents the results of the availability analysis.

Exhibit 4.8: Increase and Decrease in Final Availability for the Alternative Plant

FT Fuel Price Results ($ per barrel)	Alternative Plant	
	5% Change Final Availability	
	Increase	Decrease
FT Diesel Price	$67.88	$79.33
Crude-Equivalent Price	$52.22	$61.02
Change from Reference Plant	-$4.77	$6.68
% Change from Reference Plant	-6.6%	9.2%

The results of this analysis show that even small changes in final availability have large effects upon the price of FT fuel. A 5.56 percent increase in final availability results in a 7 percent change in FT fuel price for the Alternative Plant, roughly the same as for the Reference Plant. An equivalent decrease in final availability for the plant results in a 9 percent change in final FT fuel price, somewhat more than for the Reference Plant. Significantly, increases in availability directly increase the net cash flow from the project. As noted earlier, capital cost changes have a greater affect on pricing of FT fuel than operating costs. Changes in availability neither affect capital costs nor produce net cash flow after accounting for variable operating costs. As a result, on a percentage basis, changes in availability produce a greater percentage effect than changes in capital costs. These results, therefore, suggest that the final price of FT fuel will be highly dependent upon the operational performance of a co-production plant.

F. Acceleration/Delay in Construction Period

As in the sensitivity testing for the Reference Plant, two scenarios examine the effect of varying construction time from the base case estimate of 3 years. In the first scenario, construction time increases by 12 months to 4 years. In the second scenario, the construction time decreases by 6 months to 2.5 years. A 12-month delay represents a 33 percent change from the base construction time, while an acceleration of six months represents a 17 percent change. In the scenario with an accelerated construction period, debt repayment occurs in the same time frame as in the base case (after a year of interest capitalization during the ramp-up period) and an interest-only period of 6 months. For the scenario incorporating a one-year delay, all project costs are expended in the 3-year reference time frame, an extra year of interest capitalization is added, and debt amortization is delayed by a year. Exhibit 4.9 summarizes the results of this analysis.

Exhibit 4.9: Increase and Decrease in Construction Period for the Alternative Plant

FT Fuel Price Results ($ per barrel)	Alternative Plant	
	Change in Construction Time	
	Acceleration	Delay
FT Diesel Price	$68.85	$80.55
Crude-Equivalent Price	$52.96	$61.96
Change from Reference Plant	-$3.80	$7.90
% Change from Reference Plant	-5.2%	10.9%

The analysis shows that FT fuel price is particularly sensitive to changes in construction timelines. A one-year delay results in an approximately 11 percent increase in FT fuel price for the Alternative Plant. An acceleration of six months, in contrast, results in an approximate decrease in FT fuel price of 5 percent for the Alternative Plants. The analysis also reveals that the non-linear relationship between construction timeline and FT fuel price arises from the effect of compounding interest. The analysis does not consider any additional costs associated with the possible financing required for a construction delay.

G. Summary

The sensitivity testing shows that variations in capital costs, coal costs, output prices, plant availability, technical design, and construction time all have material impacts on the price of FT fuel. The analysis determined that the most significant risks to economic viability of a coal co-production Alternative Plant occur due to market price risk associated with crude oil products and to integration risk. A number of strategies, however, can mitigate these risks. Chapter 5 provides details concerning the likelihood that such risks will arise and outlines current approaches used in the marketplace to address these various risk factors.

IV. SUMMARY AND CONCLUSIONS

This chapter provides the results of an analysis of the impact on the economic viability of a co-production Alternative Plant that increases net power production at the expense of FT fuel production. Alternative Plants do not sequester carbon dioxide produced in the plant. (See Chapter 7 for an analysis of plants that do sequester carbon dioxide.) The analysis examines the major inputs to FT fuel price and then assesses whether the increased net power configuration offers potential advantages over Reference Plants. Exhibit 4.10 summarizes these findings, which offer important insights into the prospects for early commercial co-production plants.

Exhibit 4.10: Summary of Analytical Results for the Alternative Plant

		Alternative Plant		
		Value: +	Value: -	
Summary of Analyses	Value Change	Price of FT Fuel (CEP) $/bbl	Price of FT Fuel (CEP) $/bbl	% Change in Price from Base Case
Base Case Fuel Price		**FT Diesel = $72.65, Crude-Equivalent = $55.85**		
Debt Coverage	1.1x	$49 ($38)		
Electricity Price	+ 25%	$66 ($51)		
Sensitivity Testing				
EPC Costs	+/- 25%	$90 ($69)	$56 ($43)	+ / - 23.7%
Coal Cost	+/- 33%	$83 ($64)	$62 ($48)	+ / - 14.7%
Reduced Naphtha Output	15% of output	-	$69 ($53)	- 5.1%
Interest Rates	+/- 25%	$78 ($60)	$68 ($52)	+7.3% / -6.6%
Final Availablity	+/- 5%	$68 ($52)	$79 ($61)	-6.6% / +9.2%
Construction Time	+1 year/ -6 months	$81 ($62)	$69 ($53)	+10.9% / -5.2%

The primary conclusions of the analysis of the alternative configuration on the prospects for co-production facilities and of potential changes in significant plant variables include:

Increasing the net power production of a co-production plant does not materially affect FT fuel price

Modeling of the increased net power configuration without carbon dioxide sequestration results in a required FT fuel price of $73 (CEP: $56) per barrel (absent any change in the electricity price assumption of $59/MWh). This FT fuel price is approximately 50 cents lower than that of the Reference Plant, a differential that is very small in relation to the total FT fuel price, particularly in relation to potential sources of variation in key project parameters. Thus, an Alternative Plant without sequestration produces FT fuel at a price comparable to that of the Reference Plant. Because this price is well above the floor price for crude oil applied by credit rating agencies to new energy projects, an

Alternative Plant subject to merchant risk would be vulnerable to price swings in oil markets. As a result, if an Alternative Plant were subject to merchant risk on a substantial portion of its output, it might not be able to survive swings in the crude oil market — or even be built.

Higher electricity prices reduce the FT fuel price from an Alternative Plant to current market levels

At higher electricity prices ($70/MWh), the Alternative Plant benefits from a significant reduction of $7 per barrel in FT fuel price to $66 (CEP: $51) per barrel. Thus, prevailing conditions in the baseload power market can enhance the economics of a co-production plant and the viability of an Alternative Plant will depend on its location.

The combination of an increased power output and a long-term purchase agreement for power can enhance the credit quality of an Alternative Plant

Alternative Plants produce additional electricity at the expense of FT fuels, diversifying a co-production plant's revenue sources. So, if the owners of an Alternative Plant enter into a long-term power purchase agreement for the sale of electricity to creditworthy off-takers, they could insulate the plant against the volatility in crude oil markets more effectively than for a Reference Plant. Therefore, diversification of revenue and secure long-term contracts that are not materially correlated with crude oil price could improve the financing prospects for co-production plants.

FT fuel price sensitivity for Alternative Plants analyzed is similar to that of other co-production plants

Broadly, sensitivity testing results for Alternative Plants display the same measure of effects on FT fuel price as sensitivity testing conducted on Reference Plants. Major factors affecting FT fuel price include changes in construction cost, time to build, final availability of the plant, and technical design. As is the case with the Reference Plants, final availability estimates have the greatest influence on FT fuel price from Alternative Plants, a 9 percent increase and a 7 percent decrease, respectively, for a 5.6 percent decrease and increase in the lifetime availability of a plant. Another area of notable difference from the Reference Plant is changes in coal price. The additional quantities of coal required by an Alternative Plant make it more sensitive to coal price changes than Reference Plants: A 33 percent in coal price results in a 15 percent change in the FT fuel price produced in an Alternative Plant versus a 13 percent change in fuel produced in a Reference Plant.

Used in a risk-informed manner, incentives could "close the gap" that jeopardizes construction and operation of early commercial co-production projects using the alternative configuration

As with Reference Plants, the analysis presents a number of scenarios and risk factors which should be studied singly and together, as well as on a site-specific basis, to better understand the best methods (and, if necessary, incentives) to decrease uncertainty in the development of Alternative Plants. Addressing the key risk factors and economics through incentives applicable to specific risks and private-sector risk mitigation mechanisms could accelerate commercial deployment of these plants. Also, by matching incentives efficiently to key project risks, government could reduce its financial exposure for individual projects and increase the number of plants built with the same budget. See Chapter 6 for a discussion of the analysis of the impact and cost of a range of incentives for early commercial co-production facilities.

CHAPTER 5: BUSINESS RISK ANALYSIS AND INTERVIEW RESULTS

I. INTRODUCTION

This chapter evaluates the perspectives of experts in all aspects of co-production projects about the business risks that affect the financeability of Reference Plants.

A. Objectives and Approach

This chapter provides a financial and market perspective of the risks that may impact a co-production project's financial returns. Andrew Paterson developed, with input from the project team, and disseminated a questionnaire to industry experts drawn from the entire transaction train involved in developing co-production facilities and evaluated their responses. The entire Scully Capital team and key members of the IPT also interviewed key agents involved in the process of financing co-production facilities to "ground truth" the risk rating results and the financial analysis. In performing the work for this project task (Task IV), Scully Capital conducted five sub-tasks (see list in Chapter 1).

B. Chapter Organization

This chapter is organized into three sections:

- **Risk Rating Framework, Questionnaire Process, and Results:** This section provides a description of the background and approach of the risk rating questionnaire and response process. It then presents the findings of the risk rating exercise and provides analysis on the risk ratings.
- **Interviews with Key Agents Involved in the Financing Process:** This section presents the results of interviews with key agents involved in the development and financing of co-production facilities. The interview results complement the findings of the risk ratings analysis, offer additional insights into the risk rating results, and complement the results of financial analyses performed for other tasks.
- **Summary and Conclusions:** This section summarizes the questionnaire responses, provides interpretative analysis of the risk assessment, and distills the interview results. This section of the report draws inferences from the analysis about the significance of the most important risks and the capacity of the private and public sectors to manage them, and it also evaluates insights about financial parameters for early commercial co-production projects. Executives may be able to use these insights to enhance private-public cooperation on risk management and barrier removal for early commercial co-production facilities.

II. RISK RATING FRAMEWORK, QUESTIONNAIRE PROCESS, AND RESULTS

The purpose of this section is to develop an understanding about the perspective of the financial and business communities on the prospects for industrial gasification (co-production) projects. A risk analysis from the viewpoint of principal actors in the development, construction, and operation of these plants provides essential insight into the possible risks and barriers facing this particular industry.

The project team developed a risk rating questionnaire to identify the critical risks to achieving adequate financial returns from early commercial co-production facilities. Twenty-two respondents (out of 50 industry stakeholders to whom the questionnaire was sent) provided responses. The risk rating process assesses the business risks associated with a number of factors that may affect the decision to invest in an energy or power project, in this case specifically a plant involving the co-production of fuels, power, and/or chemicals.

Importantly, the risk analysis process incorporates the dimension of time: Business risks evolve over the several-year-long project development timeline. So, the questionnaire includes risks associated with all phases of a project's life cycle: design, development, engineering, construction, start-up and shakedown, and operation and maintenance of a co-production plant. The project timeline provides a useful perspective for evaluating how risks change over the life cycle of a co-production plant.

A. Approach

Questionnaire

The questionnaire explores the significance of potential risks associated with early commercial co-production facilities. Major risk categories include technical, regulatory, and market risks. The categories selected for use in this study are consistent with those used in analyses presented by DOE and Scully Capital at EPRI CoalFleet meetings in 2004 and 2005 and the Gasification Technologies Council Annual Meeting in 2005, the Gasification Technologies Council's Board of Director's Meeting in 2007, and other venues at which key actors in the coal gasification market space gather.[1] The major categories are consistent with those used by the study team in its evaluation of risks

[1] David Berg, Andrew Paterson. "The Business Case for Coal Gasification with Co-Production: An Evaluation of Business Risks and Potential Incentives for Early Commercial Coal Gasification with Co-Production Projects" Briefing for GTC Board of Directors. May 16, 2007. Williamsburg, VA. David Berg. "Climate VISION Risk Framework for Advanced Clean Coal Plants: Risks and Challenges". Roundtable on Deploying Advanced Clean Coal Plants. July 29, 2004. Berg, D., Paterson A., and Oakley, B. "A Risk Framework for Evaluating Investment in IGCC Plants". Gasification Technologies Council Spring Meeting. May 2004.

associated with early commercial use of a number of other advanced energy technologies, including nuclear power, bio-refineries, hydrogen, and integrated gasification-combined cycle power.[2]

Collection of Data

For domains in which industry is considering the application of new technology and new transactions are occurring, as is the case with the use of coal, comparative databases of experts are quite limited. The project team adopted the well-developed Delphi Method,[3] which the Rand Corporation developed at the beginning of the Cold War to forecast the impact of technology on warfare. This method allows experts and industry leaders to deal systematically with a complex problem or evaluation. The Delphi Method is based on a structured process for collecting and distilling knowledge from a group of experts by means of a series of questionnaires interspersed with controlled opinion feedback. Because the process preserves anonymity and, by design, seeks to avoid the disadvantages of conventional committee action, the Delphi structured process facilitates the formation of a group judgment. The approach is particularly valuable in confronting a technologically based phenomenon for which historical data points are limited or so out of date as to be of limited utility.

To obtain a variety of perspectives about risk from professionals who are well versed in coal gasification, Scully Capital drew questionnaire participants from project finance commercial lenders, investment banks, equity investors, rating agencies, mono-line insurers; plant owners or project developers; equipment vendors; government agencies; and stakeholder groups. Some of the same respondents in the same organizations participated in previous analyses undertaken by this team in March 2005 and again in 2006 (see coal-related references in footnote 2). As noted earlier, 22 respondents completed risk ratings in the fall of 2006 for 33 business risks that fall in three broad categories: technical, policy and regulatory, and market. Two responses were excluded due to incompleteness.

Description of Risks

The risks that equity and debt investors, owners, builders (engineer, procure, construct ["EPC"] contractors), operators, insurers, and others face in developing a co-production project broadly group into three primary categories noted above: technical risks, policy and regulatory risks, and market risks.

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[2] David Berg. "Business Case for New Nuclear Power Plants: Mitigating Critical Risks on Early Orders for New Reactors" Briefing for the Department of Energy's Nuclear Energy Research Advisory Committee (NERAC). October 1, 2002. David Berg, Andrew Paterson. "Understanding Gasification Incentives: Risks, Benefits, & Cost" Gasification Technologies Council Annual Conference. October 10, 2005. David Berg, Brian Oakley, Andrew Paterson. "Commercial Deployment of Integrated Gasification Combined Cycle Power Plants: An Analysis of the Cost and Effects of Potential Government Incentives" EPRI CoalFleet. July 25, 2005.

[3] Also see "The Modified Delphi Technique - A Rotational Modification" Custer, Rodney. Illinois State University. Spring 1999.

- **Technical Risks:** This category includes risks associated with inputs to construction, production, and operation, as well as uncertainties regarding system requirements and performance. These risks may be categorized as follows:
  - *Delay/Completion Risk*: The risk that material or systematic inputs to construction will delay or inhibit completion of the project (e.g., EPC capacity constraints, skilled labor constraints).
  - *Construction/Operating Cost Risk:* The risk that material costs associated with construction and operation will be higher than anticipated (e.g., high capital cost, cost escalation of materials [steel, cement], poor technical performance, construction delays).
  - *Performance Risk*: The risk that plant systems will perform below projected levels (e.g., accidents, excessive downtime).

- **Policy and Regulatory Risks:** This category includes risks associated with state and Federal policies and regulations that affect the construction and operation of co-production plants. These risks may be grouped into four categories, as follows:
  - *Investment Risk:* The risk that a policy or regulation will inhibit investment in a co-production plant (e.g., policies or regulations delay or prevent construction or operation, incentives for alternative fuels or sequestration are absent or insufficient).
  - *Delay/Completion Risk:* The risk that implementation of a policy or regulation will delay or inhibit plant construction (e.g., state air permitting actions, siting decisions).
  - *Operating Cost Risk:* The risk that a policy or regulation will cause operating costs to be higher than anticipated (e.g., value of carbon trading receipts or carbon dioxide sales does not cover costs of capture and sequestration).
  - *Performance Risk:* The risk that policies or regulations will inhibit anticipated performance (e.g., tightened environmental regulations increase costs or reduce net output, impairing plant economics).

- **Market Risks:** This category includes uncertainties regarding market prices and market demand. These risks may be categorized as follows:
  - *Investment Risk:* The risk that market conditions will jeopardize an investment in a co-production plant (e.g., long-term demand falls short of projections, interest rates rise too far, too much equity is required).
  - *Operating Cost Risk:* The risk that operating costs rise more than anticipated or revenues fall short of projections (e.g., feedstock costs rise, labor costs rise, customers breach purchase contracts, prices of competing products fall or rise slower than those made in the co-production plant).

– *Performance Risk:* The risk that market conditions inhibit anticipated operations (e.g., coal [or pet-coke] transport or mining are interrupted).

Risk Valuation and Rating by Respondents

In keeping with the core risk assessment principles discussed above, respondents rated on a five-point scale both the *probability* of a particular risk event occurring and the *severity of the impact* of the event, *should it occur*, on the commercial prospects of a co-production plant. The product of the probability and severity of impact constitutes a rating of the *risk*; the maximum rating is 25 (5 for highest probability x 5 for highest impact). These two dimensions of each risk characterize its nature and provide context useful for improving the precision of commercial risk management remedies and government policies and incentives to address certain critical risks.

Exhibit 5.1: Plot of Risks Based on their Attributes (Likelihood, Severity of Impact)

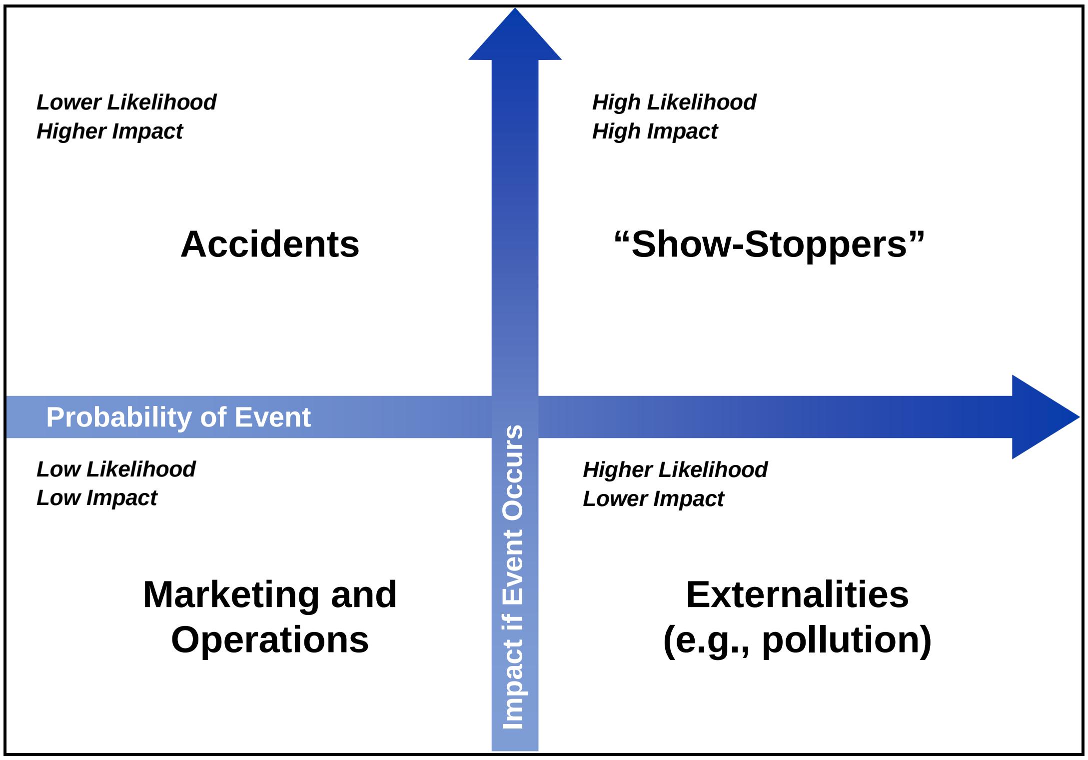


Exhibit 5.1 illustrates the four quadrants and labels the types of risks that fall within each. Final results of the analysis of the risks in the three risk categories described in the previous section will be displayed according to this format later in this chapter. By plotting the risk ratings in two dimensions — "probability of occurrence" and "severity of impact," the results can be arrayed in quadrants based on the two attributes. Two-dimensional plotting makes the nature of each risk more apparent, facilitating constructive risk management and mitigation activities.

Risks with a low likelihood and low severity tend to involve basic business operations and workforce issues, which industry typically can manage without government assistance. High-impact, low-likelihood events (e.g., a plant fire during construction, storm damage) usually can be handled via insurance mechanisms. Similarly, businesses usually can manage risk events with a low impact, but high probability, such as the management of environmental residuals, through standardization and maintenance, and with the aid of clarifying regulations and compliance processes. The most severe risks, which have a high likelihood of occurrence and carry a high impact and high likelihood, are "deal-breakers" — issues so fundamentally important that, without mitigation, they act as barriers that prevent a project from moving ahead.

This two-dimensional framework for capturing the perception of risks over a given time horizon enables project developers and interested outside parties (e.g., main customers, primary suppliers, Federal, state, or local government) to optimize their roles in the mitigation of risk, overall, and to negotiate risk management solutions based on the ability and inherent capacity of each party (government, private sector actors, and state and local communities) to best manage particular risks. Better negotiation of key risks leads to a more efficient use of resources in *both* the public and private sectors.

B. Results of Risk Analysis

Technical Risks

Exhibit 5.2 summarizes the detailed ratings for eleven technical risks.

Exhibit 5.2: Ratings for Technical Risks

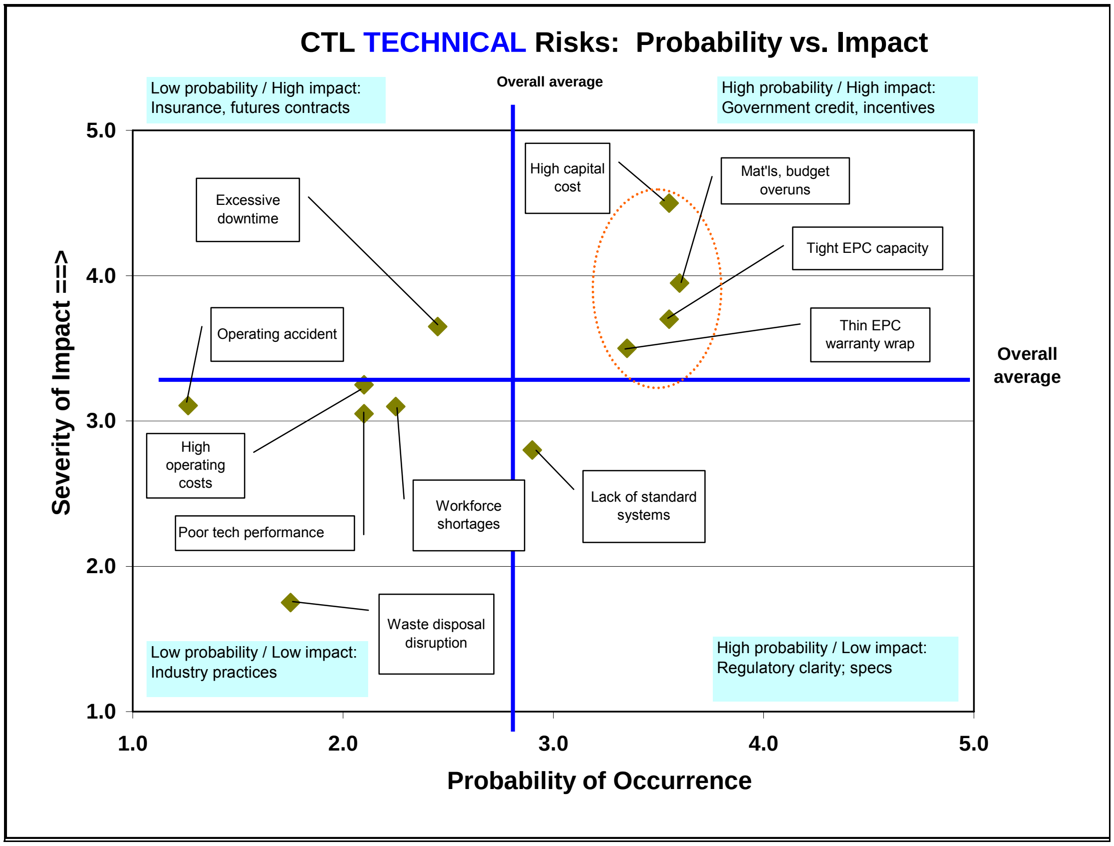
Risk Area: Technical	A Probability	B Severity	A x B Rating
1. High capital cost	3.6	4.5	16.0
2. High labor/operating cost	2.1	3.3	6.8
3. Excessive downtime	2.5	3.7	8.9
4. Poor technical performance	2.1	3.1	6.4
5. Lack of standardization	2.9	2.8	8.1
6. Lack of EPC capacity to build	3.6	3.7	13.1
7. Lack of skilled operators	2.3	3.1	7.0
8. Materials & budget overruns	3.6	4.0	14.2
9. Damage from accidents	1.3	3.1	3.9
10. Thin EPC / vendor wrap	3.4	3.5	11.7
11. Waste disposal disruption	1.8	1.8	3.1

High capital cost, which would result in high product costs, appears to be the most significant technical risk. Also of particular significance are high and rising costs of materials and/or the potential for budget overruns during construction, as well as EPC capacity constraints and the risk these constraints pose to completion.

Interpretation of Results

Exhibit 5.3 arrays the eleven technical risks in a two-dimensional plot of probability of occurrence and severity of potential impact.

Exhibit 5.3: Mapping of Technical Risks



The most significant technical risk appears to be high capital costs. Because there are significant economics of scale in co-production plants and first-of-a-kind plants cost more than $2 billion, the costs of their products may be higher than those of competing crude oil-based products. EPC costs associated with gasification plant construction may also be very high due to constrained capacity of skilled labor and high materials costs. Together, these potentially high costs pose risks for completion and threaten budget overruns. Materials costs climbed through 2006 and into 2007 due to robust global demand, limited supply, and a weakening dollar.

Other leading areas of concern include the lack of availability of an EPC/vendor "wrap" for facility performance; announcements by such co-production vendors as General Electric, Conoco Phillips, and Shell validate this concern. Note that respondents did not see as a big issue a related risk — the lack of standardized systems. The lack of standardization results in higher costs for plant performance “wraps,” but respondents appear to discount the lack of standardized systems as an issue because companies in the chemical and refining industries differentiate themselves with custom processes. In comparison, for example, the power sector demands standard designs; EPRI’s CoalFleet project has developed a standard design for a 600 MWe IGCC plant.

Less likely, but of high impact should it occur, is the risk of excessive plant downtime. Chemical plant operators are more experienced and confident with gasifier and chemical process operations and can easily store chemicals and fuels. The consensus is that owners will be convinced finally of the lower likelihood of excessive downtime only when plants are built; this expectation is clear in the low ratings for this risk.

Other areas of risk considered but projected to be of minimal significance include the risk of gasification plant products being less competitive due to higher labor and operating costs. Also of lesser concern is the risk of performance shortfalls. Operators and EPC firms are confident of performance once the plant is built and have noted that tours of working units may have contributed to an increase in the level of education and awareness on this issue. On a similar note, there are concerns about the potential deficit of operating staff to run plants, but owners are confident of their training capability and view downtime as more of a hardware issue than a labor issue. Respondents also see major accidents that may lead to regulatory penalties or severely damage a plant as manageable through the institution of safety rules, insurance, etc. Finally, respondents view as a non-issue the risk of a chronic disruption of by-product sales and disposal options (e.g., for sulfur or slag). Gasification is viewed as minimizing risk in this area because the process produces higher quality byproducts or wastes that are less expensive to dispose.

Policy and Regulatory Risk

In the area of policy and regulatory risk, respondents appear to be most concerned with the challenge that a lack of clarity about national incentives poses to the first co-production projects. Respondents rate national and state incentives as very important to improving the prospects of these facilities because they improve plant economics relative to market risk exposure. Respondents also express significant concern that national incentives — for plants, overall, and for carbon sequestration — will prove insufficient to offset high capital cost of plants and the cost of sequestration. Other policy and regulatory issues generally rate lower, in part because project developers and other respondents see co-production plants as being able to meet regulatory requirements with available equipment at a manageable cost.

Exhibit 5.4 summarizes the detailed ratings of the nine policy and regulatory risks analyzed in this study.

Exhibit 5.4: Ratings for Policy and Regulatory Risks

Risk Area: Policy and Regulatory	A Probability	B Severity	A x B Rating
12. State air permitting delays	2.2	3.4	**7.2**
13. Water treatment permit issues	1.7	2.9	**4.7**
14. Delay in "clean diesel" regulations	1.9	2.5	**4.7**
15. SCR regulations for power block	3.2	2.2	**7.1**
16. Low value for carbon trading	2.8	2.9	**8.2**
17. Regional / state policies lag	2.9	2.7	**7.7**
18. Regional policy on sequestration lag	3.0	2.7	**7.8**
19. National incentives on plants lag	3.3	4.2	**13.7**
20. National policy on $C0_2$ lags	3.2	3.1	**9.6**

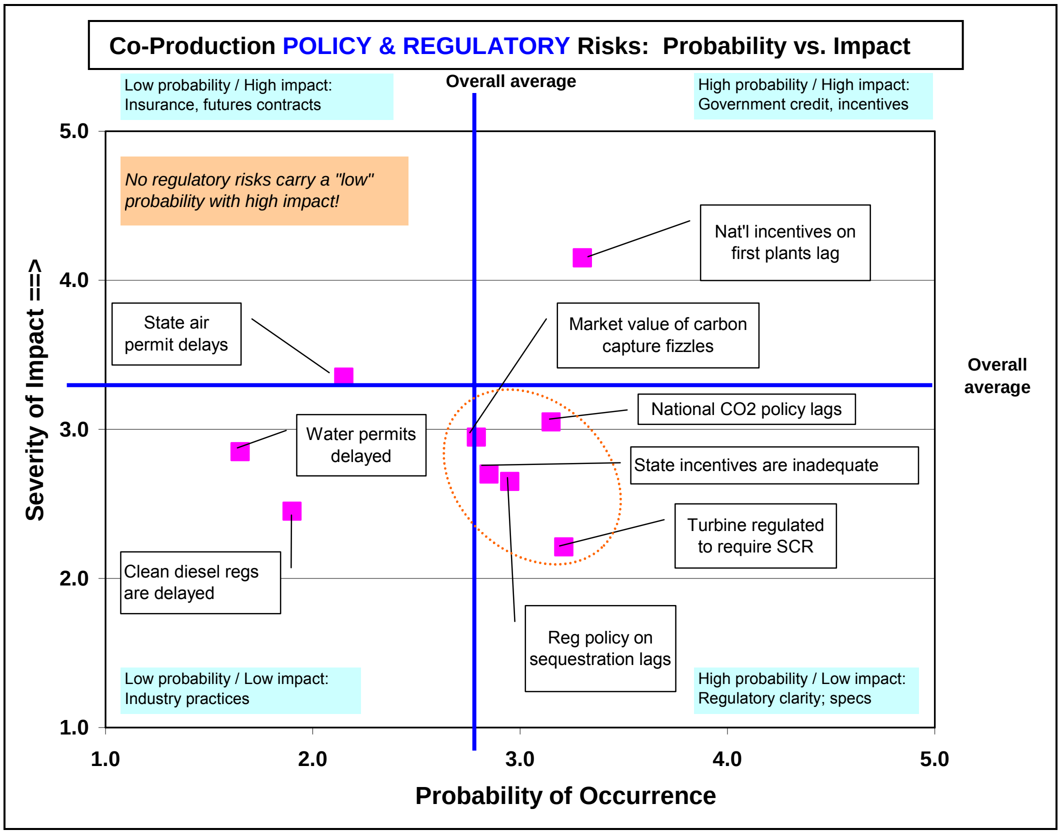
Interpretation of Results

Exhibit 5.5 plots in two dimensions the nine policy and regulatory risks to display the extent to which they may impact CTL plant construction, operation, and performance. The only policy or regulatory risk that has both a high probability and a high severity of impact is the risk that national incentives will be insufficient in assuring adequate operating margins for the first co-production plants.[4]

The plot of policy and regulatory risks reflects elevated concern about the uncertainty of environmental, regulatory, and carbon policies at both the national and state levels. The high risk rating for strength of national and state incentives seems to reflect concerns about both the pricing of co-production products and the lack of market price stability for these outputs of co-production plants. Interestingly, though, virtually none of the policy and regulatory risk issues rate both low in probability and high in impact, perhaps because these risks are known and industry expects that governments will address them in a way that maintains a level playing field. As indicated in Exhibit 5.4, policy and regulatory risks considered include those involving water treatment regulations, enforcement of clean diesel regulations, state or EPA requirement of the most advanced NO_x emission controls for the power block, and the overall lack of provision by state or national policies of sufficient incentives for sequestration.

4 Although present crude oil prices exceed the crude-equivalent price of FT fuels produced by a Reference Plant, price volatility typifies the crude oil market. As a result of this price volatility Standard & Poor's (S&P) and other credit rating agencies utilize a "long-term crude oil price assumption" for evaluating the long-term creditworthiness of large energy projects. S&P utilizes $40 per barrel as its long-term crude oil price assumption in performing its credit analyses. This figure provides a conservative estimate for evaluating long-term creditworthiness of fuel providers. This concept is discussed further elsewhere in the report.

Exhibit 5.5: Mapping of Policy and Regulatory Risks



Market Risk

Market risks, which are focused on the dynamics of supply and demand volume and pricing, create significant challenges to project developers' efforts to obtain financing. It appears that resolution of these financing challenges may be of utmost importance to the likelihood of construction of co-production plants.

Exhibit 5.6 summarizes the detailed scores resulting from the quantitative analysis of thirteen market risk ratings. These results reveal respondents' views about which market risks are the most significant to co-production plant investment and financial performance. They also help explain why no commercial co-production plants that produce FT fuels have been built yet in North America. The ratings of market risks highlight the importance of off-take agreements to the financing of projects — whether by the Federal government (risk #29 highlights DoD) or another creditworthy customer, such as a highly rated transportation corporation or regulated electric utility (risk #30). The need to assure revenues through long-term off-take agreements from creditworthy government or private customers is the leading issue, given the price of fuel projected in this analysis, and this viewpoint is reflected in the rating of availability of long-term purchase agreements by creditworthy parties as the second and fourth highest-rated risks overall and the two most highly rated market risks.

Exhibit 5.6: Ratings for Market Risks

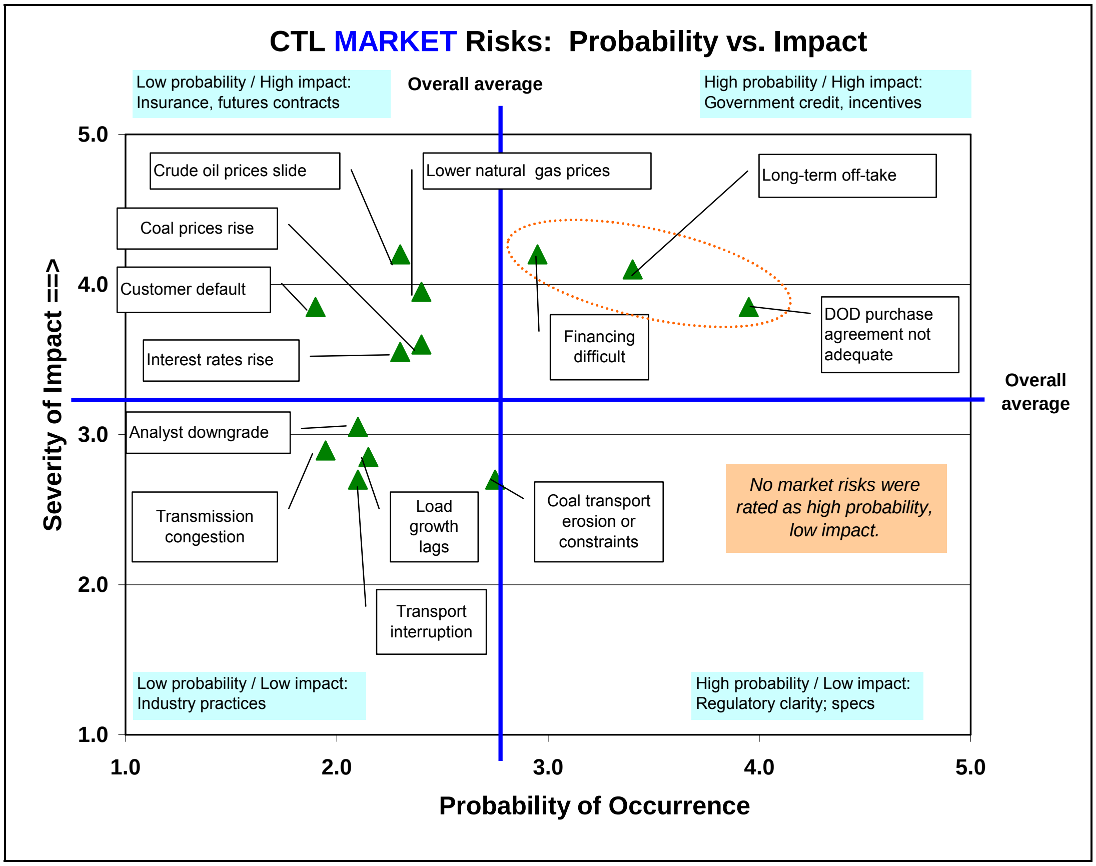
Risk Area: Market	A Probability	B Severity	A x B Rating
21. Long-term demand falls short	2.1	2.7	**5.7**
22. Coal transportation erosion	2.8	2.7	**7.4**
23. Transportation interruptions	2.2	2.9	**6.1**
24. Lower gas prices (<$4/Mbtu)	2.4	4.0	**9.5**
25. Coal prices rise	2.4	3.6	**8.6**
26. Interest rates rise	2.3	3.6	**8.2**
27. Crude oil prices fall (<$40–$50)	2.3	4.2	**9.7**
28. Financing difficult (equity, terms)	3.0	4.2	**12.4**
29. DOD purchase agreement thin	4.0	3.9	**15.2**
30. Long-term off-take inadequate	3.4	4.1	**13.9**
31. Customers breach off-take	1.9	3.9	**7.3**
32. Transmission congestion	1.9	2.9	**5.6**
33. Analysts downgrade ratings	2.1	3.1	**6.4**

Respondents also view project financing as problematic — a potential Achilles heel for co-production projects — because of the potential for fuel and other plant products to be, albeit periodically, non-competitive. Respondents regard project financing risk as a derivative of the combined impact of other risks that companies cannot manage effectively. In this regard, respondents remain skeptical about the likelihood that DoD will, in the end, enter into long-term purchase agreements. Respondents also express concern about commodity price risk — in responses to questions #24 and #27 (on the risk that competing gas and oil prices will drop) and in responses to question #25 (on the risk that coal prices will rise). In sum, the combination of the lack of availability of off-take agreements, high capital costs, inadequacy of EPC warranties, and uncertainties about government incentives and carbon policy, none of which are fully resolved, drives respondents to the view that financing will be difficult or impossible. Greater difficulty in financing could lead, for example, to deeper equity and reserve requirements, higher interest rates, shorter debt tenors, or additional collateral.

Interpretation of Results

The plot in Exhibit 5.7 reflects that the most significant market risks concern issues that directly affect the certainty of revenues, which in turn directly affects the financeability of a plant. Of utmost concern is the availability of long-term off-take agreements for fuel or other products; these agreements are the leading instrument for managing the risk of price volatility in product markets and, therefore, for assuring capital recovery. A project will likely be structured to have financial reserves to be used to maintain payments on plant debt during periods of cash flow insufficiency, but these reserves will not be infinite. Long-term off-take agreements are a cushion against an extended period of low prices that, otherwise, would drive a project entity into default on its debt obligations when reserves are exhausted. In the wake of numerous merchant energy failures in 2000 - 2002, financial firms are indicating that solid, long-term revenue agreements with creditworthy off-takers are a key to obtaining financing. Respondents also rate possible high interest rates, high equity requirements, and volatility in the fuel markets as posing a potentially significant impact on plant investment.

Exhibit 5.7: Mapping of Market Risks



A high interest rate environment similar to those of the 1970s and 1980s would significantly impede project financing. Similarly, higher equity requirements could reduce projected returns, but respondents believe that this event is unlikely to occur. Although a decline in natural gas prices (below $4/MBtu) is rated as a lower probability event, a long-term decline in crude oil prices to $40 - $50 per barrel and/or a significant increase in coal prices could threaten the competitiveness of co-production plants. The state of fuel and other product markets plays a large role in the competitiveness of gasification plants and the financial returns from a project. Respondents track these market risks closely and, in particular, expect to lock up longer-term agreements to manage these risks.

Respondents express much less concern about several market risks: long-term demand for products, coal transportation, plant investment adversely affecting owners' credit or equity ratings, and transmission congestion. “These are issues that are dealt with early in the development and siting phases; they are not deal-threatening issues,” said one respondent. Owners would not consider building unless they foresee clear demand growth. After the Federal Reserve Bank hiked rates during most of 2006, the risk of substantial additional interest rate hikes rated just below average, and current interest rate levels are affordable.

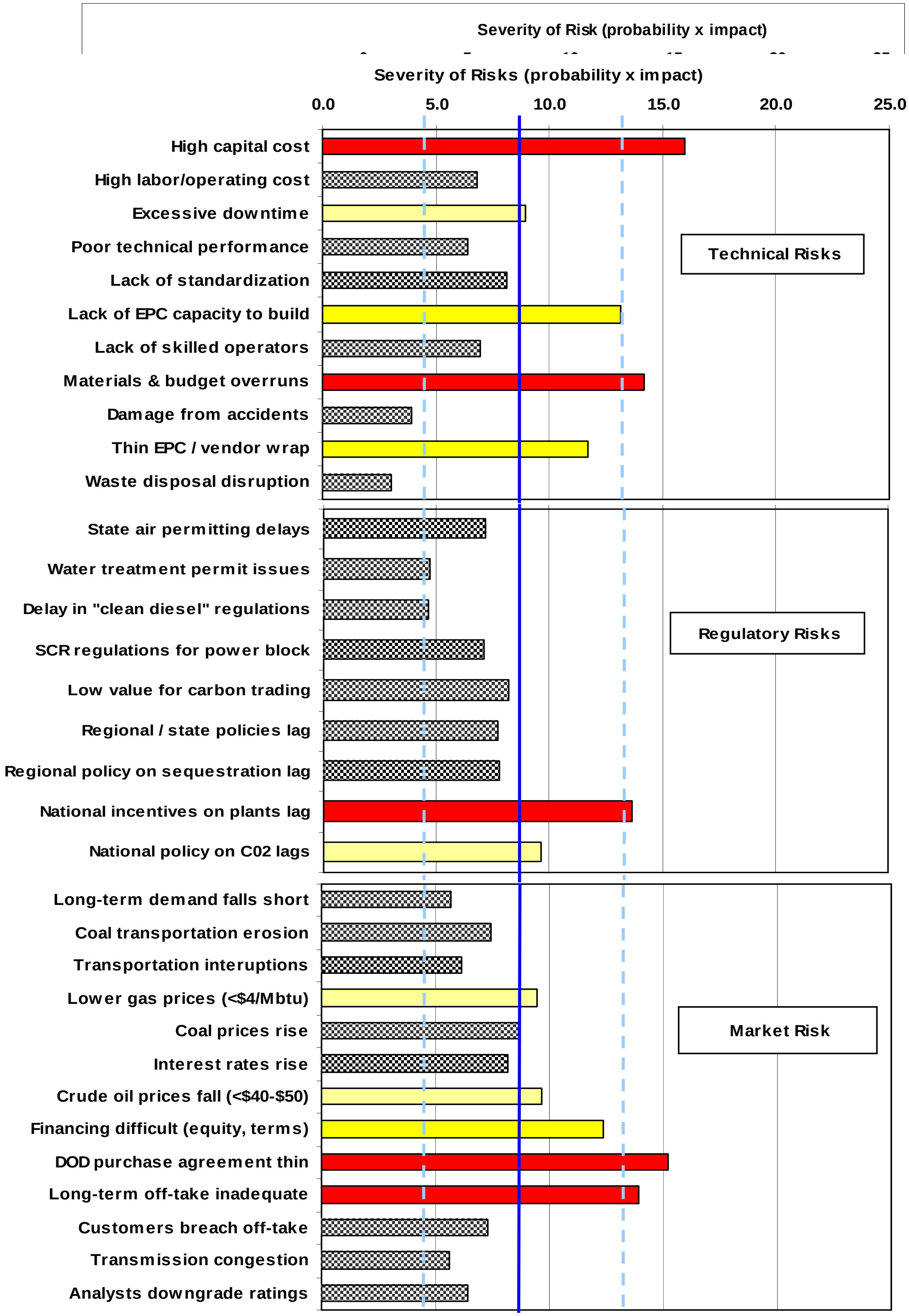
C. Summary of Risk Rating Results

Respondents did not identify any barriers that will prevent the construction and operation of co-production projects, but several risks rise to the level that the project developers cannot address them alone or with the assistance of private risk-mitigation instruments. The risk rating responses converge on several themes that are important to the development of financing for early commercial co-production facilities. In particular, high capital costs represent a threshold area of concern.

- **Revenue and off-take/purchase risk:** Respondents express serious concerns about the volatile nature of the commodity markets in which co-production facilities will compete. The projection that FT fuels must be priced above $50 per barrel to provide adequate financial returns makes purchase agreements, which can cushion price volatility, potentially very important. The potential for DoD or other creditworthy government or private entities to be unable to undertake adequate purchase agreements could leave this risk unaddressed.
- **High capital cost:** Respondents rate as their greatest concern high fixed costs associated with a co-production facility. Concerns over high materials prices and potential budget overruns in the context of backlogged EPC contractors and a weakening dollar reinforce high capital cost as a threshold concern to respondents. The implication of this risk is that products of a co-production facility may not be competitive in hydrocarbon fuel markets, which experience significant price fluctuations. Unlike most power utilities that may build IGCCs, producers of liquid fuels cannot pursue rate regulation.
- **Facility technical performance:** While the technologies employed in co-production facilities have been in existence for decades and are well understood, the fact that a commercial scale co-production facility has not been built in the United States represents an area of significant concern, as reflected in the elevated risk rating for availability of EPC wraps. Technology performance risk is typically handled by assigning this risk to an EPC contractor. However, the lack of standardized designs for co-production facilities and the limited risk-bearing capacity of EPC firms to (1) absorb an undertaking of this magnitude and (2) to wrap the facilities’ performance risk make this a key area of concern.
- **Financing risk:** Due mainly to the threshold risks identified above, the market risk related to financing ranks as a key area of concern.

Exhibit 5.8 provides a summary of the ratings compiled in the fall of 2006 for each risk question. The solid purple line shows the average rating (9.0 on a 25-point scale) in 20 questionnaire responses for 33 technical, policy and regulatory, and market risks. The purple dotted lines show one standard deviation (4.6) of the ratings on either side of that average. The rating issue with the highest standard deviation or variance around the mean was #20 ("national policy on carbon"), which adds "differences in perception" as another dimension to the uncertainty on that issue. In general, the risks with low ratings also show low variability among respondents. To highlight the key concerns of respondents, ratings of risks above the average by more than one standard deviation are shown in red, while risks rated above average but less then a full standard deviation are shown in yellow.

Exhibit 5.8: Summary of Risk Ratings



III. INTERVIEWS WITH KEY AGENTS IN THE FINANCING PROCESS

To supplement the risk ratings analysis, Scully Capital conducted an outreach effort to leaders in the development and financing of co-production facilities by interviewing senior executives, project developers, engineering firms, and financial institutions. Importantly, interviewees spoke on the condition that their comments would not be subject to specific attribution.

The interviews focused on several important themes associated with this "Business Case" study. These themes are the most highly rated risks identified in the risk ratings:

- Capital Cost Risk;
- Technology Risk;
- Revenue and Output Commodity Risk; and
- Financing Risk.

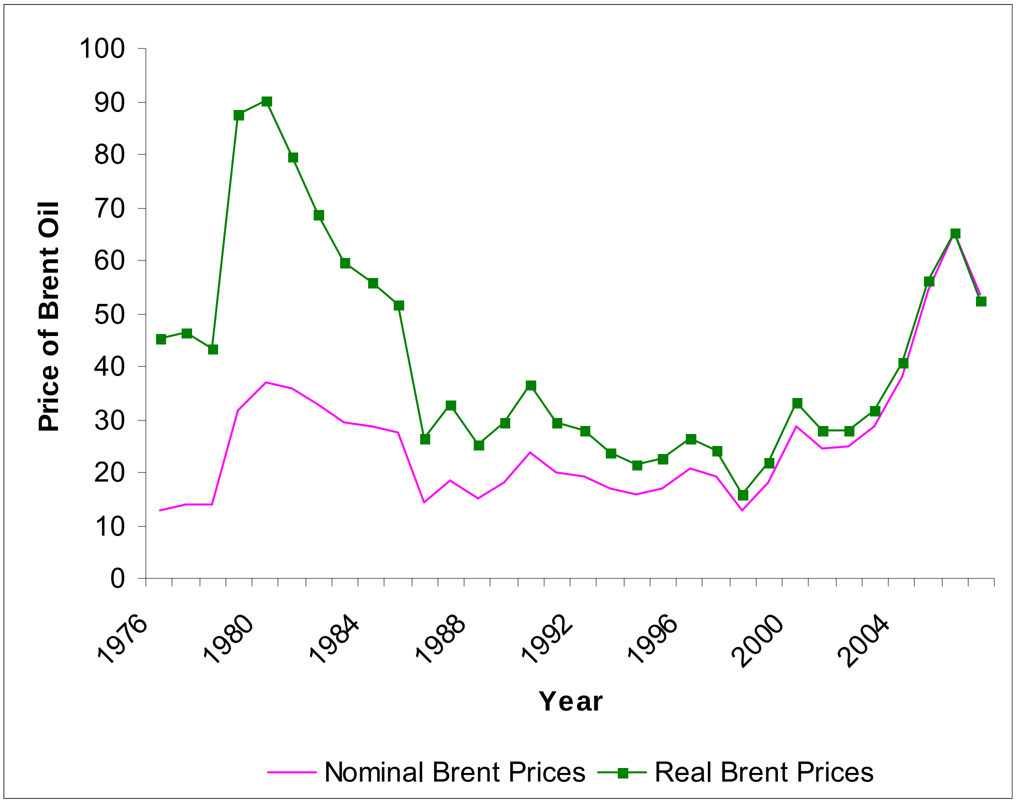
Each interview concluded with a discussion of how incentives proposed or in place at the Federal and state levels may be able to address key project risks.

A. Capital Cost Risk

Capital cost risk relates to the total capital cost of a co-production facility relative to the total capital cost associated with other sources of fuel. As discussed in Chapter 2, co-production facilities are capital-intensive. Yet, to the extent the products will compete with products made from crude oil, the project will need to be competitive with the long-term expected pricing for crude on the open markets. Volatility experienced in the pricing of crude over the past 30 years makes the assessment of capital cost competitiveness a challenge.

Exhibit 5.9 presents the pricing of crude on a nominal basis and real basis since 1976. As this exhibit indicates, crude oil price fluctuates significantly, making future prices very difficult to predict; the only safe prediction is that prices will continue to be volatile in the future. Reflecting the uncertainty of prices, Standard & Poor's (S&P) utilizes $40 per barrel as its long-term assumption for oil prices (as of late 2006 and early 2007) in its credit analyses of U.S. hydrocarbon producers. S&P's assumptions are intentionally conservative in order to provide a reliable basis for evaluating long-term debt obligations. Modeling shows that a Reference Plant would have to obtain *on a sustained basis* a crude oil price above $50 per barrel to be competitive. The cost differential ($50 versus $40, or $10) suggests that it would be very difficult to develop a coal-to-liquids plant absent off-take arrangements to assure product sales during periods of below-average pricing and government incentives to help close the cost gap; no plants have been built in North America.

Exhibit 5.9: Pricing of Crude Oil



Notably, however, the assessment of capital cost risk in these terms does not encompass the hedge value of locking in a long-term source of fuel supply at predictable costs. And, severe hurricane damage to Gulf Coast refineries and oil and gas production equipment in 2004 and 2005 piqued interest in alternative fuel sources, especially inland production facilities distant from hurricane tracks. Thus, without prejudice, both industry and government entities are exploring the notion of developing such alternative sources of supply for risk reduction/energy security.

Risk Rating

As noted above, high capital costs rank first in the risk rating analysis and can be considered a “show-stopper” risk. Other related risks also rank very high. Specifically, concerns over material and budget cost overruns during construction and the current strain on global EPC capacity to build projects rank second and third among the technical risk ratings.

Results from Interviews

Feedback from the interviews is consistent with the results of the analysis of technical risk ratings. Interviewees, and most of all “first movers,” share a concern about high capital costs. Moreover, they repeatedly express their concern about the ability of the EPC community to deliver such facilities. Observations include:

- **Current EPC market conditions:** Several interviewees note that worldwide demand for EPC services is very strong at the moment. In addition, even the largest EPC firms typically are thinly capitalized, limiting the volume of business they can warranty at any one time. Accordingly, project sponsors have a limited ability to negotiate with EPC firms; they are finding that transferring risks in the construction contract is very difficult to achieve, particularly considering the size, scale, and technical uncertainties associated with a first-of-a-kind co-production plant. Interviewees also note that, while getting the attention and commitment from EPC firms today is difficult due to firms' full order books, this issue may subside as firms work through their backlogs or if the global economy slips into recession.
- **Construction timeframe:** Most interviewees anticipate that a 48-month timeframe is the minimum period over which a plant can be designed and constructed. The 36-month construction period begins after preliminary engineering and project development activities are complete. This schedule is consistent with that of the Reference Plant, in which a 36-month construction term commences after financial close.
- **Total construction costs:** While several interviewees indicate that the total construction cost appears to be "in the right ballpark," they have some concern about the adequacy of contingency embodied in the construction numbers. Specifically, Scully Capital received comments that additional contingency will be needed in the budget if a project sponsor intends to pursue a traditional lump-sum, turnkey arrangement in which the EPC contractor covers the risks associated with costs, schedule, and performance.
- **EPC contractor capacity:** In addition to confirming the current strength of the EPC market, a number of interviewees express concern over the capacity of individual EPC contractors to underwrite the risks embodied in a traditional EPC contract. Specifically, the number of firms eligible to provide engineering and construction services under a traditional EPC arrangement is limited by the large size of co-production facilities. This capacity constraint, in turn, further exacerbates the tight market conditions in today's EPC market.

B. Technology Risk

Technology risk is associated with the operating performance of a facility, including the timing of construction completion, ramp-up of operations, and process efficacy. In the context of the interviews, technology risk includes:

- **Completion risk:** Will the facility be completed on time?

- **Performance risk:** Will the facility perform according to design specifications in terms of overall capacity, availability, and efficiency, and will it make products to specifications?
- **Budget risk:** Will the facility be completed within the anticipated budget?

Traditional project financings address technology risk by avoiding early commercial technologies and/or by avoiding first-of-a-kind project types and/or by allocating risk to the EPC contractor.[5] If the EPC contractor accepts technology risk, it will guarantee to build a facility that works to specification and complete the facility on time and within budget. To the extent the facility does not perform according to specification on an integrated basis, the contractor must provide sufficient funds to offset the impact of performance shortfalls, as defined. Delay damages typically are sized according to the interest expense incurred on a daily basis, and budget concerns are addressed through a fixed price contract.

Risk Rating

As noted in the risk rating section, the lack of availability of EPC performance wraps and the lack of a standard EPC offering rank as key risks associated with early commercial co-production projects.

Results from Interviews

The feedback from interviews is consistent with the results of the analysis of risk ratings. While virtually all interviewees indicate that performance guarantees are critical, they generally recognize that the current state of the EPC market, combined with the size of a co-production facility and the need to integrate several unit processes, requires different approaches for addressing technology risk. Notably, none of the interviewees indicate any doubt over whether a co-production facility could be developed and constructed. Observations include:

- **Performance guarantees are essential:** Interviewees universally agree that, in order to successfully undertake the development of a co-production facility under a project finance structure, guarantees covering cost, schedule, and performance are essential to the financing structure. The interviewees from the lending community indicate that, absent a full performance guarantee, a co-production project simply could not be financed in today's capital markets.
- **Required guarantees will increase cost:** The interviewees are generally in agreement that, although the mechanisms for addressing technical risk may vary, addressing technical uncertainty is likely to increase the total cost of a project. The increase would arise from increased owner contingency levels, first loss

[5] See the section of Chapter 3 on "Technical and Financial Assumptions for Reference Plants" for a discussion of project finance.

reserves, or EPC contractor contingency. In fact, more than one interviewee indicates that addressing performance risk via a traditional EPC framework could come at a premium of 15 percent to 30 percent over the estimated construction cost.

- **Alternative structures will likely emerge:** Several interviewees indicate that, given the current conditions of the EPC market and the practical issues associated with providing a performance wrap for a large, complex, and expensive facility, it is possible that alternatives to the standard EPC wrap structure could emerge. Potential structures identified include:
  - *Reopeners in EPC contract for specific risks:* This type of structure is often used in construction contracts in which a single commodity or risk can materially influence the constructed cost of the project. For example, in the shipbuilding industry, EPC type contracts can include automatic adjustments for the price for steel. This type of mechanism could be used for co-production facilities.
  - *Multiple EPC-type arrangements*: Several interviewees indicate that, given the scale of the unit processes embodied in a co-production facility, an owner/sponsor could absorb the integration risk of major unit processes and rely on multiple EPC arrangements addressing these unit processes. For example, the air separation unit could be fully wrapped by the industrial gas company hired to develop and construct the facility. However, the integration of these major unit processes would be wrapped by the owner/sponsor via contingent equity contributions and/or a first loss reserve.
  - *Technology provider providing process warranties*: Although this approach would deviate from the principle of having a single point of accountability, one interviewee suggests that the technology licensor could provide a guarantee for process efficacy, while the EPC contractor could guarantee substantial completion of the facility. With this approach, the owner and its financing sources would have recourse to the technology provider, which would "wrap" the technology of the facility. In this case, the owner would again assume the integration risk of the project, relying on an EPC contractor to guarantee substantial completion and a technology provider to guarantee process efficacy. As in other approaches, the owner would budget standby funds in the form of contingent equity or a first loss reserve.

C. Revenue and Output Commodity Risk

Revenue and output commodity risk relates to the market for the products produced by a facility. This risk takes on heightened importance given uncertainties about to the market price of fuel outputs and co-products produced by the facility relative to prevailing commodity prices on the market. As indicated in the Reference Plant results in Chapter 3, the crude-equivalent price of FT fuels produced by a Reference Plant is expected to be approximately $56 per barrel. This price would be competitive in today's market, but the plant would be vulnerable to crude oil price fluctuations. (Note that, to this point, coal prices are not as volatile as oil and gas prices, and long-term coal supply contracts are available for power generating projects. So assuming a long-term supply agreement for coal, on the input side co-production plants may face lower feedstock risk than oil refineries, with commodity risk for plants with coal feedstocks concentrated on the off-take side.)

Because of the historic volatility of crude oil pricing, lenders and rating agencies would have concerns over the long-term competitiveness of a Reference Plant. In fact, Standard & Poor's utilizes $40 per barrel as its downside scenario for the future of crude oil prices.[6]

Against this background, interviewees agreed that an off-take contract represents a key requirement for financial feasibility due to concerns over long-term commodity risk. One interviewee summarized this concern by saying:

> *"Everyone's biggest fear is that oil markets will plummet, rendering the project worthless."*

In fact, DOE's experience in 1985 with the bankruptcy of the Great Plains synfuels facility in South Dakota concretely illustrates this risk. With the return of higher oil and gas prices, that plant returned to profitability, and DOE has benefited from its residual interest in the project.

Risk Rating

The risk rating results are consistent with feedback from the interviews. Specifically, questions 27, 28, 30, and 31 explore risks associated with off-take arrangements. Of these, question 30 ("long-term [greater than 5 years] off-take agreements for fuel or products are inadequate or unavailable") ranks as the highest-rated market risk and the second highest-rated risk overall.

Results from Interviews

While interviewees agree on the need for an off-take arrangement, they offer different thoughts on how to structure such an arrangement. In fact, several interviewees indicate that it may be possible to structure an off-take arrangement that would either not cover 100 percent of the output or not be coterminous with the debt associated with the facility. Other observations include:

- **Strength of off-take agreement will determine debt capacity of the project:** Several interviewees indicate that the strength and breadth of the off-take

[6] "Standard & Poor's Raises Price Assumptions for U.S. Oil and Gas Sector; Little Ratings Effect Foreseen" Standard & Poor's. September 18, 2006. See also "Industry Report Card: Diverging Natural Gas And Crude Oil Prices Result In A Mixed U.S. Oil And Gas Outlook" Table 1 on page 6. Standard & Poor's. September 11, 2007.

arrangement will determine how much debt the project can support. Specifically, lenders will look to the product pricing that will meet debt service requirements plus a margin (to assure a minimum debt service coverage ratio of approximately 1.1x) and certainty of acceptance (delivery). An off-take arrangement of approximately 58 percent of output would be needed to meet this standard.[7] This observation has important implications for the capital structure of the project and/or the amount of output that will have to be "locked up" via an off-take arrangement.

- **Off-take pricing could be structured to reflect market conditions:** Closely related to the percentage of output covered under an off-take arrangement is the pricing of the off-take arrangement. Specifically, rather than reducing the volume of material secured under contract, project owners could structure, within limits, the pricing of the material to move with the prevailing market of the commodity being produced. For FT diesel, for example, the output pricing from a co-production facility could be established based on a relationship to the prevailing price of crude oil. Depending on the capital structure of the project, lenders could simply require that a floor be imposed on the price such that revenues would always be sufficient to cover debt service plus a margin (to achieve a 1.1x debt service coverage ratio). Assuming all of the product available from the plant could be sold, this price would be approximately $54 per barrel (CEP: $42). A counterpart upper limit, or cap, could be applied as a balancing mechanism. It is important to note that equity investors and the customer would need to get comfortable with the potential that prices well above the $54 per barrel could be realized, as limited by the cap. While equity investors have a significantly greater appetite for risk, their investment will be based, in part, on an expectation of pricing going well above current levels.
- **Term of agreement could potentially be less than debt amortization period:** While interviewees generally agree that five years represents an off-take agreement term that is too short for a facility of this scale, a number of interviewees indicate that it may be possible to have the debt extend beyond the term of the off-take agreement. Alternatively, it may be possible to structure the debt such that it only partially amortizes during the term of the off-take agreement and carries a bullet maturity for the unamortized debt upon expiration of the off-take agreement. Given the long-lived nature of a co-production facility and the potential for debt to be partially amortized by the end of the off-take agreement, the project offers the potential for refinancing in order to maintain liquidity during a period when the project is exposed to merchant risk.
- **Alternative pricing mechanisms could be available:** In addition to varying the term of an off-take agreement, several interviewees suggest that an off-take arrangement could be developed that would move with the crude oil market. However, they indicate that a floor would need to be established to protect the interest of lenders (by assuring a revenue stream sufficient to keep debt

7 This result is based on the pricing of FT fuel at $73 per barrel.

payments current). Notably, this floor would be well below the $56 per barrel crude-equivalent price calculated for the Reference Plant, but no less than the "floor price" for crude. In fact, based on input from the interviews, the floor price would need to service the debt plus provide a small cushion for uncertainties. Based on the Reference Plant financial structure and assumptions, Scully Capital estimates this amount to be in the range of $54 per barrel (CEP: $42) to $57.30 per barrel (CEP: $44). In order to attract project equity under such a structure, the off-take price would also move up with the market. Therefore, an off-taker could achieve long-term fuel assurance under a pricing structure that would move with the market. However, by design, this structure would provide only a limited price hedge.

- **Potential for a "tolling" option:** One interviewee suggests that an off-take contract for a creditworthy private purchaser could be structured as a "tolling" arrangement in which the facility would process a customer's coal for a fixed price. This approach would remove one source of volatility from the product cost. To illustrate, the cost of feedstock for the co-production facility modeled in the Reference Case is approximately 60 percent of operating cost. Under a tolling arrangement, this cost would be paid for under a different contract vehicle and the off-taker would be contractually bound to provide sufficient fuel for the facility to operate.

D. Financing Risk and Government Incentives

A final area explored with interviewees is financing risk associated with a co-production facility, i.e., the availability of debt and equity investors and the terms under which they are willing to invest. While it is clear that the interviewees believe performance wraps and off-take agreements are absolute conditions to the availability of financing, the terms of the financing, if available, are also critical. Specifically, if the pricing related to debt and equity proves to be too high, the plant would not produce a competitive product. Alternatively, if the debt tenor were too short, the output pricing would have to be set in order to meet debt service coverage ratios, again resulting in a non-competitive output price. Therefore, the terms, conditions, and pricing of the project will affect overall financial feasibility.

Discussions with interviewees under this risk category largely focus on the incentives currently available at the Federal level to encourage energy projects. Given the timing of the interviews, the comments largely focus on the DOE loan guarantee program under Title XVII of EPAct 2005, *as reflected in loan guarantee guidelines issued by DOE in August 2006*. (DOE indicated then that it would issue a program [*issued in September 2007*[8]] rule which could differ in significant respects from the guidelines.)

8 See www.lgprogram.energy.gov.

Risk Rating

The risk rating results indicate that financing is an area of significant concern. Specifically, the risk of financing a plant proving difficult rated 16, placing it among the five highest rated risks.

Results from Interviews

Feedback from the interviews provides important insights that complement the risk rating analysis. Interviewees generally agree that no barriers exist that prevent the development of a project, but they agree that government-sponsored incentives would be required to facilitate the development of a co-production facility. They consider loan guarantees, in particular, critical to getting a project underway. Interviewees offer several specific insights and comments related to the DOE loan guarantee program and, in particular, to the loan guarantee guidelines DOE published in August 2006. Significant comments from this part of the interviews are detailed below.

- **Equity return requirements are likely to be in the range of the high-teens to the low-twenties for early commercial co-production projects:** The Reference Plant analysis assumes an after-tax internal rate of return (IRR) range of 17 percent to 19 percent. Interviewees agree that interest rates are in the right range and that equity requirements will ultimately depend on the specific terms and conditions of an off-take arrangement. One developer active in the coal-to-liquids market indicates that no equity investors they have been in contact with are indicating an IRR requirement of less than 15 percent; many indicate an IRR requirement of greater than 20 percent. Importantly, several interviewees indicate that purely financial investors tend to be on the high side of this range, while strategic investors may require a lower equity return in exchange for participation in the project.
- **Tax benefits provide indirect benefits for creditworthiness:** Interviewees indicate that tax benefits enhance after-tax equity returns but provide little or no value for creditworthiness. The only exceptions to this indication would be a case in which the presence of a tax benefit allows greater amounts of equity to be invested in the project for the same return and a case in which tax benefits can be monetized, such as is the case with excise tax credits and production tax credits. In these instances, a revenue source will be created through the sale of tax credits to a third party. Lenders may consider these tax credits a reliable source of revenue. However, several interviewees suggest that they require projects to be self-sustaining absent the effect of a tax incentive.
- **Loan guarantees are critical:** Given the first-of-a-kind nature of an early commercial co-production facility in the United States, interviewees indicate that loan guarantees represent an important requirement for the financial feasibility of a co-production plant. Most of the interviewees were familiar with the DOE loan guarantee program and several were familiar with the language of the loan

guarantee program's guidelines. While the interviewees are very interested in the loan guarantee program, they express significant reservations regarding certain elements of the program's guidelines.[9] Their observations include:

– *Structure of program could limit capital available:* DOE indicated that, under the guidelines, it will guarantee up to 80 percent of a loan to a project. Since the legislation allows the government to provide a loan guarantee for up to 80 percent of project costs, interviewees refer to the structure proposed under the guidelines as the "80/80" structure. Several indicate that the 80/80 structure will limit debt capacity in the capital markets because restrictions on bond funds preclude a bond buyer from purchasing debt that is only 80 percent guaranteed. The un-guaranteed nature and subordinate lien status of the remaining 20 percent would render the debt instrument far below the investment threshold for large institutional investor bond funds. In fact, one interviewee suggests that only three financial institutions are sufficiently large to underwrite deals of this size with an 80/80 debt structure. For smaller-sized transactions (e.g., renewable energy projects), interviewees suggest that commercial banks may be able to work with the 80/80 structure. However, large transactions (greater than $1 billion) would need to access the public debt markets through a bond issue. In order to market this commercial paper under competitive terms, interviewees suggest that it is better to fit the debt instrument to the market because that would result in the lowest overall cost of debt capital to the project and would improve the project's prospects for success (i.e., it would reduce default prospects).

– *Pricing on an 80/80 debt instrument could be excessive:* A number of interviewees suggest that, because of the un-guaranteed 20 percent of the debt and the inability to strip the guaranteed debt from the un-guaranteed debt, purchasers of the debt would likely price the instrument at the lowest common denominator (i.e., at the 20 percent subordinated debt rate). This view was not shared by all interviewees, although several interviewees indicate that the pricing on the subordinate 20 percent piece would be in the range of 600 to 700 basis points over LIBOR.[10] Of note, the government's exposure in reducing the guaranteed portion of the debt from 100 percent to 80 percent will not be reduced linearly because, depending on the project, the compromised value of the loan guarantee could increase interest cost and diminish overall credit quality, *increasing exposure* for the government. Interviewees note that simply requiring more equity is a more straightforward approach.

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9 As noted earlier, DOE issued program regulations for the loan guarantee program in the fall of 2007. Because these regulations differ in some respects from the program guidelines, some of these comments no longer are relevant to the actual loan guarantee program. They continue to have value in that they indicate the requirements for financing any capital-intensive project, such as a co-production facility.

10 London Interbank Offered Rate. "Libor" represents the interest rate that major international banks charge each other to borrow U.S. dollars in the London money market.

– *Interviewees recommend utilizing more traditional subordinate debt:* A number of interviewees express the opinion that, if the DOE desires to bring private sector lending discipline to the underwriting process, then it would be easier to impose a cap on the amount of senior guaranteed debt and require the project to utilize traditional subordinated debt. This approach would allow the terms of the subordinate debt to conform to market norms (thereby increasing available capital), and the project would benefit from the scrutiny imposed by the subordinate lender's underwriting process. Conformance with market norms could be particularly important to the extent that borrowers seek to credit-enhance the 80/80 debt instrument with guarantees from other government entities.

As a general matter, the interviewees believe that loan guarantees could be critical to managing "first-of-a-kind" risks associated with the development of early commercial co-production facilities. However, as a whole, they believe that the loan guarantee guidelines could be improved to better fit with the financial market as it exists today and, in turn, attract favorable pricing and terms on the debt.

IV. SUMMARY AND CONCLUSIONS

The questionnaire and interview results develop a clear picture about project risks and financial returns from the perspective of potential owner/operators of co-production projects, their business partners, and other key players. While the results of other parts of this study suggest that coal gasification with co-production is technically and economically feasible, perceived risks related to a facility's cost, market competitiveness, and technical efficacy rise to the level that they represent threshold barriers to early commercial projects of this type. The results of the risk rating process and the interviews provide important insights to these "show-stopper" risks and offer ideas on how to mitigate these risks effectively and efficiently.

Several conclusions emerge from these results which offer important insights into the necessary conditions for successful early commercial coal gasification with co-production projects.

High capital costs, output commodity risk, and technical uncertainty, which rank as the highest rated risks, will limit financeability

The concern that high fixed costs of a co-production facility will combine with material and budget overruns ranks as a threshold issue among respondents and interviewees. The implication of these risks is that products of a co-production facility would not be competitive given significant and frequent price fluctuations in hydrocarbon fuel markets. The volatile nature of commodity markets in which co-production facilities must compete heightens respondents' belief that purchase agreements with DoD or other creditworthy entities in the public or private sectors are an essential part of a plant's financing plan. Further, the fact that a commercial co-production facility has not been built in the United States represents an area of significant concern: Concerns over technology risk, particularly those associated with the integration of several unit operations in the first U.S. co-production plants, exacerbate this concern.

Current conditions in the engineering and construction (EPC) market amplify concerns over high capital cost

Strong EPC-firm backlogs and a rapid increase in the cost of construction materials over the past several years heighten concerns over high capital costs for early commercial co-production plants. Rapid rates of economic growth in the developing world, in particular in capital-intensive infrastructure projects, and the weakening dollar increase this risk by driving up international demand for EPC services and dollar-denominated costs for projects that EPCs manage.

An off-take arrangement, which establishes a dependable market for a facility's outputs, is critical to alleviating concerns about capital cost risk

By establishing a reliable purchaser for a substantial portion or all of a co-production facility's output, off-take arrangements (or "purchase agreements") address price risk in volatile energy markets. Off-take agreements with a creditworthy purchaser assure that debt can be serviced as long as a plant operates. If a purchase agreement is in place, project sponsors can address capital cost risk with the use of loan guarantees or other incentives and technical risk by establishing reserves and contingencies or requiring performance wraps. Purchase agreements are so important to co-production projects that Scully Capital includes them in the core financial structure of the Reference Plant. Reserves, contingencies, and performance wraps provide another level of assurance that debt will be serviced. The added cost of these risk mitigants will be reflected in the cost for FT fuels.

Numerous structuring options exist for off-take agreements

Feedback from lenders, investment bankers, and credit rating agencies suggest that numerous options exist for structuring an off-take agreement to support project debt requirements. These options include structuring an off-take term that is shorter than the term of the debt, creating an off-take pricing structure that floats with the market, and varying the percentage of the plant's output that is covered by the off-take arrangement. Lender concerns focus on a project's ability to generate sufficient cash flow to meet debt service needs. The output price needed to accomplish debt service sufficiency will be approximately 74 percent of the total price of products of a Reference Plant. Lenders will focus on this relationship since it provides a basis for estimating plant competitiveness in the event of default and foreclosure.

The need to address technical uncertainty by increasing reserves and contingencies reinforces capital cost concerns

A project's financial plan needs to address technical uncertainty as a condition of obtaining project financing. Reserves and contingencies added for this purpose will further increase the all-in cost of co-production projects. Contractors' construction budgets may include higher contingency amounts, and project sponsors may increase reserve funding set-asides. The impact of these steps will be a further increase in concerns about capital cost and the risk increased costs convey to the competitiveness of a facility's outputs.

Interview results confirm estimates of required equity returns

The financial assumptions embodied in the Reference Plant financial analysis (see Chapter 3) include an equity after-tax internal rate of return (IRR) requirement of 17 percent to 19 percent. Although lower rates of return have sometimes been proposed publicly, the interviews confirm the 17 percent to 19 percent return range, although it is possible that potential project sponsors could accept lower returns (and on-balance-sheet financing) to establish a market position. In addition to the pricing levels estimated for plant outputs, these required equity returns are an important consideration in designing options for off-take arrangements. Specifically, while lender concerns will guide the minimum requirements for off-take arrangements, equity requirements will need to be considered when structuring maximum pricing under a purchase agreement.

Government incentives are essential for the first few plants

Despite the assumption of a purchase agreement, the nature and mutually reinforcing effect of the highest-rated project risks (i.e., capital cost risk, market [output price] risk, technical risk) contribute to the need for government incentives for most early commercial co-production projects. The market appears to be unready to address these key risks without government assistance, at least in part. Moreover, the risk ratings and interviews highlight concerns that government incentives may prove insufficient to facilitate the development of the first U.S. commercial co-production facilities. Incentives that reduce the cost of production can be combined with purchase agreements assumed in the Reference Plant structure to enhance the financial prospects of a project.

Loan guarantees are critical, but concerns exist about their framework under the program guidelines

Interviewees were unanimous in their belief that DOE loan guarantees represent a critical incentive for facilitating early commercial co-production facilities because, by enhancing a project's creditworthiness, they can both increase the availability of debt financing and reduce interest rates. Further, they are a flexible tool, the terms of which can be shaped to help manage specific project risks, and their cost can be contained via the use of strict underwriting criteria.

The interviewees also agree that the structure of the loan guarantee program *as originally proposed in DOE's guidelines* would limit the efficiency and effectiveness of debt instruments backed by a DOE loan guarantee. Specifically, interviewees cite the non-stripping requirement (which binds together the guaranteed debt portion and the un-guaranteed portion) as the single biggest obstacle to designing an efficient capital structure. In their view, this requirement would limit the number of debt investors significantly and, in turn, diminish competition. This outcome could serve to raise interest rates and/or decrease debt tenors. Several interviewees indicate that the un-guaranteed portion of project debt could be more efficiently funded with subordinate debt that is not tied to the senior guaranteed debt. Interestingly, interviewees express less concern over DOE's plan to limit guarantees to less than the 80 percent of project cost authorized by EPAct 2005 Title XVII. (Concerns about the 80 percent limitation have been mitigated by the program regulations issued recently.)

CHAPTER 6: ANALYSIS OF FINANCIAL INCENTIVES

I. INTRODUCTION

This chapter builds on the results presented in Chapters 3 and 4 by providing an analysis of the differing effects of various incentives on the economics and financeability of co-production Reference Plants. This chapter also builds on the results presented in Chapter 5 of the risks associated with co-production plants by providing an analysis of the applicability of incentives to the key risks that affect the decision to build and operate or not build and operate a plant. The results presented in this chapter thus enhance our understanding of the potential impact of a range of government incentives on the commercial prospects for industrial gasification projects, the applicability of specific incentives to key project risks, and the cost of utilizing one or more incentives to support a Reference Plant.

A. Objectives and Approach

The objective of this chapter is to provide an analysis of the impact and cost of selected incentives on the economics and financeability of a co-production plant, as well as their applicability to key project risks.[1] This study is intended to provide insights to sponsors in these key industries and the government on the effect of financial incentives on plant economics and government budgets, particularly with respect to the business risks that the private sector will have the greatest difficulty managing without government incentives. Others should benefit from this study, as well, including state and local governments, plus other stakeholders in industry.

The analysis presented in Chapter 3 suggests that, without the use of incentives, the crude-equivalent price of FT fuels from a mid-size bituminous co-production plant would need to be in the range of $55–$60 per barrel over the life of a project.[2] Although this price is below current prices, it is above the long-range outlook for crude oil used by the financial industry in evaluating the prospects of a project. Thus, early commercial plants will require a long-term off-take arrangement with a creditworthy counterparty in order to facilitate financing. Advocates for the commercial deployment of coal gasification with co-production suggest that government incentives could further facilitate project financing through improved economics or risk assumption.

1 The analysis was performed in the fall of 2006, predating the issuance of the DOE loan guarantee program's Final Rule by approximately one year. Accordingly, analyses presented herein were based on Scully Capital's experience in analyzing and quantifying the financial and budgetary impacts of government incentives.

2 In a scenario in which IRR is 15 percent and other financial assumptions remain the same, the crude-equivalent price of FT fuels would need to be in the range of $47 per barrel. This price is still above the long-term floor price.

As detailed in Chapter 3, the Reference Plant analysis utilizes a non-recourse project financing structure. Under this type of financing structure, a project “stands on its own” and its cash flows provide the underpinnings of creditworthiness. Conversations with developers and financiers indicated that this type of structure would likely be utilized for the first few plants. Importantly, this type of structure insulates project sponsors from the full risk of the project, allowing specific risks to be shared by several participants in the project as negotiated. The same plant serves as the “Reference Plant” analyzed in this chapter. In performing the work for this task (Task V.A.), Scully Capital conducted four sub-tasks, as outlined in Chapter 1 (Introduction):

Note: Separately, Scully Capital analyzed various incentives supporting a Reference Plant with carbon capture, compression, and sequestration (i.e., carbon dioxide captured during plant operations is compressed, transported through a pipeline, and sequestered, either in a saline aquifer or to enhance oil recovery). Chapter 7 presents the results of this analysis.

B. Report Organization

The remainder of this chapter is organized into three sections, as follows:

- **Background on Incentives:** This section provides a description of selected incentives, including tax incentives and credit incentives enacted in the Energy Policy Act of 2005.
- **Impact of Incentives:** This section provides the results of the analysis of the selected incentives, including the impact of incentives on the economics of co-production, the financeability of a plant, and Federal budget score. This section also comments on the applicability of particular incentives to key risks, as identified by project principals and outside financial experts.
- **Summary and Conclusions:** This section summarizes the findings and draws inferences from the analysis with a particular focus on results and conclusions that may be useful in risk management and in the identification of barriers that need to be removed for early commercial co-production facilities.

II. 0BACKGROUND ON INCENTIVES

Federal, state, and local governments have frequently used direct and indirect incentives to mobilize private sector investment in projects and to advance policy objectives in numerous sectors of the economy. Types of direct incentives include: Tax-based incentives, credit-based instruments, insurance, and other forms of direct government participation, such as grants and assurance of dispatch. Other incentives can also be valuable tools for mobilizing private sector investment, such as permitting acceleration, rate-basing, and other indirect forms of risk sharing. The private sector also can provide incentives in various forms, including warranties, insurance, purchase agreements, and the like.

Although governments or private parties interested in encouraging early commercial use of an advanced energy technology are likely to be familiar with providing risk mitigating instruments independently, the effects of incentives usually are *not* mutually exclusive. So, the private sector and government agencies can heighten the effect and enhance the cost-effectiveness of incentives in addressing key risks, such as high capital costs, technology risk, and off-take risk, by collaborating on the use of incentives. By considering incentives via a “toolkit” approach in which an incentive is matched to a key risk and a combination of incentives is used to maximize the chance of project success and minimize cost, government and the private sector can optimize the use of incentives to obtain the greatest “bang for the buck” and to best achieve their objectives.

A. Tax–Based Incentives

Since the introduction of oil and gas tax incentives in 1916, the United States has used tax policy to address problems or distortions in energy markets or to achieve specific social, economic, or environmental objectives. After a burst of energy-related incentives in the 1970s and a hiatus in new incentives through much of the 1980s, a more activist energy tax policy has reemerged with policy goals of reducing dependence on foreign oil and achieving environmental and economic objectives.

The Energy Policy Act of 1992 was the defining legislation in the 1990s. It provided a range of tax incentives targeting energy efficiency, alternative fuels, and alternative-fueled vehicles. Subsequent legislation, including the Jumpstart Our Business Support Act of 2004 (“JOBS”), Military Construction Appropriations, Emergency Hurricane Supplemental Appropriations Act of 2005, Energy Policy Act of 2005 (“EPAct 2005”), and Safe, Accountable, Flexible, Efficient Transportation Equity Act – A Legacy for Users (“SAFETEA-LU”) have added or extended energy tax-based incentives.

Today, numerous energy sources benefit from tax-based financial incentives, along with energy efficiency. Exhibits 6.1, 6.2, and 6.3 on the pages that follow provide, for illustrative purposes, a snapshot of some of the tax incentives aimed at encouraging non-renewable and renewable energy sources, and energy efficiency.

Exhibit 6.1: Examples of Tax-Based Incentives for Non-Renewable Energy Sources

Source	Tax Incentives	Comments
Coalbed Methane	• Section 29 Tax Credit • Coalbed methane provided 7.7% of total use in 2005 (1720/22,241 bcf) • Production is up 10 fold since 1990.[3]	• Tax incentives have helped increase production 17-fold from 1989 to 2003. EIA estimates that the production of coalbed methane is 6% of domestic natural gas production.[4] • New facilities entered into service at a reduced rate since 1992 (when the tax credit lapsed).
Natural Gas	• Percentage depletion at 27.5% of revenue for marginal producers • Expensing of interest during construction (IDC) for marginal producers • Passive loss limitation • Enhanced oil recovery tax credit • Federal Royalty Relief for deep wells in Gulf of Mexico • 24-month amortization of geological and geophysical costs.	• After Federal royalty relief, production of deep water oil and gas increased five-fold (500%) in the Gulf of Mexico's Outer Continental Shelf.[5] • Domestic natural gas production meets 81.3% of the country's natural gas needs.[6] • Some OCS territory was opened as a result of legislation passed in December 2006; however, new supplies from these territories will take some years to come on line.
Oil	• Percentage depletion at 27.5% for marginal producers • Expensing of IDC for marginal producers • Passive loss limitation • Enhanced oil recovery tax credit • 24-month amortization of geological and geophysical costs.	• Incentives have helped decrease the rate of decline in domestic oil production. • After the 2006 election, the new Democratic leadership in Congress promised to place these incentives under scrutiny and, possibly, to review them.
Coal Gasification	• 50% expensing of FT equipment • Excise tax credit for FT fuels • Investment Tax Credit (ITC) increased to 20% from 15% for clean coal projects • Excise tax credit of $0.50 per gallon of fuel produced in a FT reactor.	• Incentives in EPACT 2005 & SAFETEA-LU. • Incentives designed to encourage early commercial coal gasification projects. • The IRS received 49 applications for $4.6 billion in ITCs. EPACT 2005 authorized $1.65 billion. IRS awarded $1 billion in ITCs to 9 projects.[7]
Nuclear Energy	• 1.8 cents/kWh production tax credit for 8 years after facility is placed in service. National limit for production tax credit is 6,000 MWe.	• EPACT 2005 offers multiple incentives for nuclear energy designed to encourage orders of new nuclear power plants after a gap of over 25 years. • 25 new nuclear power plants are under consideration.[8]

[3] Natural Gas Monthly. Energy Information Administration (EIA). January 2007. http://tonto.eia.doe.gov/dnav/ng/ng_sum_snd_dcu_nus_a.htm.
[4] "U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2003 Annual Report" Energy Information Administration. 2004.
[5] LA-1 Coalition – Facts and Figures. http://www.la1coalition.org/facts.html.
[6] National Gas Monthly. January 2007. Energy Information Administration
[7] "EPACT Gasification Investment Tax Credits 'Oversubscribed'" Gasification Technologies Council. August 23, 2006.
[8] "The Energy Policy Act of 2005 Anniversary Report" United States Senate Committee on Energy and Natural Resources. August 8, 2006.

Exhibit 6.2: Examples of Tax-Based Incentives for Renewable Energy Sources

Source	Tax Incentives	Comments
Wind	• 1.9¢ production tax credit • 5-year accelerated depreciation • Tax exempt bond interest • Renewable Energy Production Incentive	• Industry sources indicate that Federal incentives reduce the cost of wind projects by 65%.[9] • A lapse in the production tax credit led to a halt in wind power projects.[10]
Biomass Waste to Energy	• 1.8¢ production tax credit (for closed loop biomass grown only for energy production) • 0.9¢ production tax credit (for open loop biomass, landfill methane, MSW) • 5-year accelerated depreciation • Tax exempt bond interest • Renewable Energy Production Incentive	• Industry sources indicate that a subsidy of 1.7¢ to 2.4¢ per kilowatt hour, which corresponds to the extra labor required for biomass, is needed to make the industry competitive with fossil fuels.[11] • When the production tax credit momentarily lapsed, interest stopped for more than 700 landfill sites already approved by the EPA.[12]
Solar	• 1.8¢ production tax credit • 5-year accelerated depreciation • Tax exempt bond interest • 30% business tax credit • Renewable Energy Production Incentive	• According to Solar Energy Industries Association, the U.S. solar industry has not progressed as far as Germany's and Japan's because in those countries the industry received a higher level of initial financial support that allowed them to achieve efficiencies of mass production. [13] • Federal incentives, in combination with state programs such as those in New Jersey and California, are expected to significantly increase demand for solar cells.
Geo-thermal	• 1.8¢ production tax credit • 5-year accelerated depreciation • Tax exempt bond interest • 15% depletion • Renewable Energy Production Incentive • 10% business tax credit	• The industry has had limited success in tapping new sources, some of which are located in remote and pristine places. • Industry trade associations acknowledge that current technology does not allow for effective drilling for geothermal resources; drilling is currently 30%-50% of system cost.[14]
Biodiesel	• 50 cents per gallon excise tax credit for biodiesel • $1 per gallon excise tax credit for agri-biodiesel from certain types of virgin oils.	• Goal: Promote production of diesel-equivalent fuels from domestic sources • Special emphasis given to small and independent producers.

9 Martin, K. "Tax Issues and Incentives for Wind Power Projects" Chadbourne & Parke LLP. March 2004.
10 Garman, D. "The Future of Renewable Energy in America's Rural Communities" March 15, 2004. http://www.eere.energy.gov/office_eere/congressional_test_031504.html.
11 Center for Energy Efficiency and Renewable Technologies. http://www.ceert.org/ip/biomass.html.
12 Skinner, J. CEO and Executive Director of Solid Waste Association of North America. Testimony to House and Ways and Means Committee. June 2001.
13 "Our Solar Power Future: The U.S. Photovoltaics Industry Roadmap Through 2030 and Beyond" Solar Energy Industries Association. September 2004.
14 Hulen, J., Wright, P. "Energy Brochure" Geothermal Energy Association. April 2001.

Exhibit 6.3: Examples of Tax-Based Incentives for Energy Efficiency

Source	Tax Incentives	Comments
Home	• 10% tax credit up to a ceiling for windows, doors, insulation, and roofing. • Tax credits ranging from $50 to $500 for energy efficient heating and cooling systems.	• Net of investment, partners in the program saved $6.8 billion in 2005.[15]
Cars	• Up to $3,400 in tax credits. Tax credit based on efficiency gains. Credit decreases after manufacturer reaches sales of 60,000 on product.	• Sales of hybrid cars increased from less than 5,000 per month in January 2004 to greater than 26,000 per month in August 2006.

Since input prices, market competition, regulatory mandates, and technology and financial risks influence the economics of energy investment and production, it is very difficult to measure directly the effectiveness of tax-based incentives in achieving policy objectives. However, tax incentives that encourage energy policy objectives represent a long-standing tradition for the Federal government, and there is little doubt that such policies improve the economics of proposed projects. Accordingly, for projects that are manageable from a risk standpoint, tax-based incentives can play a role in mobilizing investment.

B. Federal Credit Programs

Numerous Federal departments and agencies use credit programs to advance policy objectives. These programs utilize direct loans, loan guarantees, and lines of credit. Credit programs are targeted at correcting a capital market imperfection or reducing the cost of borrowing or making it possible to borrow — all to encourage certain activities. By providing access to capital or by providing access to capital under more favorable terms than are available in the private capital markets (e.g., lower interest rates, longer debt tenors, reduced collateral requirements) and/or by increasing leverage, credit programs can improve project economics and mobilize investment.

More than 75 Federal credit programs are in force today, covering everything from student loans to housing for homeless veterans. Challenges inherent to Federal credit programs include maintaining the difficult balance between the policy objectives of the program and underwriting responsibilities associated with implementing and administering the program. While the common intent of these programs is to address gaps in private capital markets, repayment of loan principal and interest must be reasonably assured. Therefore, programs directed at industries that face significant and/or structural impediments to reaching or regaining profitability may face challenges that could undermine the effectiveness of the program. In fact, both industry and government criticized the Emergency Steel Guaranteed Loan Program due to its

[15] "Energy Star and Other Climate Protection Partnerships: 2005 Annual Report" U.S. Environmental Protection Agency. October 2006.

inability to effect any improvements in the steel industry. On the other hand, programs aimed at specific projects for which economic soundness can be analyzed on a discrete basis or programs aimed at encouraging the development of a new industry have shown positive results.

The Federal government uses regulations promulgated under the Federal Credit Reform Act of 1990 ("FCRA") to assure sound and consistent implementation of Federal credit programs and to determine the budgetary cost of these programs and the cost of credit enhancement they offer. Notably, FCRA was enacted *after* the expiration of earlier DOE loan guarantee programs. Under FCRA, the budgetary cost of a credit program is represented by the present value of expected credit losses under the program (the "subsidy cost"), plus any administrative costs not recovered through program fees. This budgetary cost requires an upfront appropriation or a payment by the borrower of a "credit risk premium" sufficient to offset the subsidy cost and an administrative fee.

Exhibit 6.4 summarizes a number of Federal credit programs that encourage the development of a specific industry or sector of the economy.

A key issue to consider in implementing Federal credit programs is the target borrower. In the energy industry, Investor Owned Utilities (IOUs) that operate in regulated state markets or major oil and gas concerns may not favor credit instruments if they already enjoy ample access to low-cost debt capital. On the other hand, developers of independent projects may favor credit-based instruments, which help them gain access to capital at more reasonable rates and terms than are otherwise available to them in the private capital markets.

Exhibit 6.4: Examples of Federal Credit Programs

Program/Agency	Type	Year	Purpose/Rationale
U.S. Department of Energy - Advanced Energy Sources	100% Loan Guarantees	2005	Loan Guarantees for advanced energy projects that reduce, avoid, or sequester air pollution or anthropogenic greenhouse gas emissions
Transportation Infrastructure Finance and Innovation Act Program - Department of Transportation (Federal Highway Administration)	Direct Loans Lines of Credit	1999	Promote surface transportation projects: highway, transit, passenger rail and multimodal projects.
U.S. Gas Pipeline Loan Guarantee - U.S. Department of Energy	100% Loan Guarantees	2004	Will guarantee loans to finance up to 80% of a new pipeline costing $18 billion to transport natural gas from Alaska to the 48 states
Launching our Communities' Access to Local Television Loan Guarantee Program - U.S. Department of Agriculture (Rural Utilities Service)	Partial Loan Guarantees	2000	To encourage and assist entities to facilitate access, on a technologically neutral basis, to signals of local television stations for households located in nonserved areas or underserved areas.
Railroad Rehabilitation and Improvement Financing Program - Department of Transportation (Federal Railroad Administration)	Direct Loans and Loan Guarantees	2000	To support the railroad industry, after deregulation in 1980s.
Emergency Steel Guaranteed Loan Program - Department of Commerce	80% Loan Guarantees	1999	To address the financial crisis experienced in the late 1990s by steel companies which led to reduced volume, lower prices and financial losses.
Various Loan Programs - Small Business Admnistration	Direct Loans and Loan Guarantees	1953	Provide assistance to small business providing advocacy, management, procurement, and financial assistance services
Title XI Program - U.S. Department of Transportation (Maritime Administration)	100% Loan Guarantees	1937	Promote the growth and modernization of the U.S. Merchant Marine and US shipyards.
Rural Utilities Service Electric Program - Department of Agriculture Rural Utilities Service	Direct Loans and Loan Guarantees	1936	To encourage electricity utilities to provide services to rural America.
Ex-Im Bank - Export-Import Bank of the United States	Direct Loans and Loan Guarantees	1934	Export promotion, including nuclear energy projects.
Air Carrier Guaranteed Loan Program - Department of Treasury	Less than 100% Loan Guarantees	2001 (no longer in effect)	To assist air carriers that suffered losses due to the terrorist attacks of 9/11 and to whom credit was otherwise not reasonably available. The program's objective was to facilitate a safe, efficient and viable commercial aviation system in the United States.

C. Insurance

Federal insurance programs cover a wide range of risks that the private sector has been unable or unwilling to cover, particularly if coverage is deemed to provide a major benefit to society. Despite some common elements, Federal insurance programs share some common elements, but they vary in many important respects, including size, length of government commitment, frequency of activation, and program budget scoring. The government's size and sovereign power provide it with the unique ability to offer insurance when the private market is unable or unwilling to do so. Specifically, the fiscal size of the government makes it better able to absorb large losses if insurance reserves are not sufficient. In addition, the government may be able to recoup some of these losses with future premium collections or sales of assets in recovery, effecting a pooling of risks over time to the extent that premiums accurately reflect risk. The government can also attempt to spread the costs of these risks by providing insurance nationwide and/or mandating participation.

Although insurance programs have varying degrees of effectiveness for the industries they serve, they generally increase the stability and predictability of business operations and, therefore, encourage investment. Exhibit 6.5 provides a summary of several industry-oriented government insurance programs.

Exhibit 6.5: Examples of Federal Insurance Programs

Program/Agency	Year Enacted	Purpose/Rationale
Standby Support Delay Risk Insurance *U.S. Department of Energy*	2005	Aims to promote the construction of new nuclear power plants by decreasing "bureaucratic and legal issues that delay their startup".
Terrorism Risk Insurance *U.S. Treasury*	2002	Ensures the availability of property and casualty insurance for acts of terrorism.
Deposit Insurance *Federal Deposit Insurance Corporation*	1993	Insures domestic deposits in commercial banks, savings banks, savings associations, and thrift institutions.
Pension Insurance *Pension Benefit Guaranty Corporation*	1974	Protects the retirement income of participants and beneficiaries covered by private-sector defined benefit pension plans.
National Credit Union Share Insurance *National Credit Union Administration*	1973	Insures members' shares in Federal and state-chartered credit unions that qualify for insurance.
Political Risk Insurance *Overseas Private Investment Corporation*	1971	Promotes and facilitates U.S. investment in emerging market economies by helping businesses manage political risk.
National Flood Insurance Fund *Federal Emergency Management Agency*	1968	For flood prone areas, makes flood insurance available to property owners living in communities that joined the program; encourages floodplain management efforts to mitigate flood hazards and reduce federal spending on disaster assistance.
Federal Crop Insurance Corporation Fund *Department of Agriculture*	1938	Protects crop farmers from unavoidable risks associated with adverse weather, plant diseases, and insect infestations.

As is the case with Federal credit programs, targeted insurance programs facilitate industry development. The budgetary cost for such insurance programs is difficult to measure due to the varying nature of the risks that the Federal government assumes under different programs and for different projects. However, the Federal government's size, unique ability to underwrite certain risks, and ability to pool risks industry-wide and even economy-wide enables it to manage and mitigate its risk exposure in ways that are not possible in private insurance markets.

D. Other Federal Incentives

Other Federal incentives for early commercial projects include various forms of direct participation in the form of grants and cost sharing. The government also can participate as customer to a project, serving to address market risks and the public interest. Government policymakers utilize these types of incentives, which tend to carry direct financial impacts to projects, widely. Some of these incentives are costly from a Federal budget perspective and thus may have limited value in encouraging commercial use beyond the projects that benefit directly — in contrast to their frequent use in co-sponsorship of research, development, and demonstration projects. Grants and cost sharing have a budgetary impact equal to the grant or cost share and, when compared to a credit incentive, have a larger impact on the Federal budget than a credit incentive that offers the same financial benefit to a project. Moreover, the amount of cost share or grant is likely to fall well short of what would be required to encourage commercial deployment beyond a limited number of projects, if any, so incentives such as cost shares and grants have less value in stimulating widespread adoption of a new technology by an entire industry.

E. State and Local Incentives

State and local financial incentives usually are geared toward economic development (e.g., increasing employment opportunities in state, helping a local company expand, using natural resources located in a state) or environmental improvement. States can stimulate co-production projects through tax incentives, off-take agreements, indemnification of liability, rate-basing, and other incentives.

- **Tax Incentives:** State tax incentives range from accelerated depreciation, employment incentives, and investment tax credits to exemptions or reductions in property taxes.
- **Off-take Agreements:** States (or the Federal government) can become off-takers for products from a project. A long-term purchase agreement with a creditworthy off-taker is an essential assumption in the financing structure of the Reference Plant; some states can provide such an agreement. In addition, purchase agreements structured differently can function as incentives by insulating project financing sources from specific project risks.

- **Indemnification of Liability:** Capture of carbon dioxide and subsequent sequestration or use (e.g., in EOR applications with sequestration) is a key potential benefit of co-production. Lack of a fully developed liability framework associated with the transportation and long-term storage of carbon dioxide is a significant issue that may hamper the development of co-production projects. States (or the Federal government) could stimulate co-production projects by providing indemnification of the movement of carbon dioxide through pipelines and to liability associated with carbon dioxide sequestration. Alternatively, some kind of Federal- or state-chartered carbon trust or a private insurance mechanism could spread the liability risk for a premium.
- **Rate-basing:** In states that have not de-regulated, states can create a strong incentive for co-production projects by rate-basing part or all of their outputs. This incentive would decrease investor risk, allowing investors to decrease their return requirements and their plants to potentially provide long-term supplies at a stable and lower rate than otherwise possible.
- **Credit Enhancements:** Some states encourage economic development through credit programs. Illinois, for example, recently announced an initiative to extend its credit to back bonds issued on selected IGCC and co-production projects planned in the state.
- **Permitting Acceleration**: States can help companies shave months off the development cycle for a co-production project. For projects with a large capital cost, such as co-production projects, the time savings can translate to a significant savings in a project's total cost.

A particular state incentive can have a large or small impact on the prospects of an individual project depending on the specific characteristics of the project and the magnitude of the incentive provided.

III. IMPACT OF INCENTIVES

This section presents results from the analysis of selected financial incentives on the economics of a Reference Plant producing 32,502 barrels per day (bpd) of FT fuels and 725 MWe of electricity that uses bituminous coal, has a project finance structure, and benefits from a purchase agreement for a substantial portion of the plant's production. It then examines whether the application of an incentive would improve the financial feasibility of the Reference Plant. The analysis and results follow for:

- Tax incentives;
- Credit incentives (e.g., loan guarantees);
- State incentives;
- Other incentives (e.g., grants, purchase agreements); and
- A combination case combining multiple incentives.

Federal tax incentives that are available singly or in combination include investment tax credits, accelerated depreciation, excise tax credits, and tax exempt bonds. Some states may provide a range of incentives through public utility commissions, economic development agencies, energy agencies, and tax provisions. A list of incentives available in states promoting co-production plants is provided in this section. The Federal government and states sometimes provide other incentives, including grants and purchase agreements (or their equivalent).

Because EPAct authorized DOE to issue loan guarantees to eligible projects, the loan guarantee is the probable form of a credit incentive. The loan guarantee section of this chapter analyzes different options under which a loan guarantee could be administered under the statute.

The applicability of an incentive to a specific project risk, the financial "lift" it can provide to a project, and cost to the government are key elements in weighing the benefits of these incentives. Cost to the government is quantified as the "budgetary impact."

- For tax-based incentives, Scully Capital estimated budgetary impact based on the revenues lost to the U.S. Treasury as a result of the incentive over the standard 10-year window used for budget analyses and legislative proposals ("10 Year Budget Window"). For comparison purposes, Scully Capital assumed that the budget window and the start of production would coincide. This assumption results in production and the budget window beginning in FY 2009 and ending in FY 2018. It should be noted that the budgetary impact and the total cost of the incentive over the life of a project are not necessarily equal when the incentive affects cash flow beyond the budget window, as in the case of accelerated depreciation. The total cost of the incentive over the life of the project to the government is termed "total costs."

- For loan guarantees, budgetary impact is based on the estimated net present value cost of the loan guarantee according to the guidelines presented under OMB Circular A-129. Regulations established under the Federal Credit Reform Act (FCRA) of 1990, as amended, require agencies to determine the net present value cost of a loan guarantee (referred to as the "credit subsidy premium"); this amount represents the expected loss to the government based on the anticipated risk of default, the anticipated timing of the default, and the potential for recoveries in default. The credit subsidy premium must be funded before a Federal agency issues a loan guarantee. The credit subsidy premium can be funded through a Federal agency's budget authority or by a third party (including, under EPAct Title XVII, a project sponsor). For loan guarantees and other credit incentives, the budgetary impact is calculated at the time of financial close for the loan being guaranteed.

The Reference Plant results estimate an FT fuel price of $73 ($56 on a crude-equivalent price, or "CEP") per barrel.[16, 17, 18] For each incentive, the price of FT fuel produced by the Reference Plant was adjusted to achieve a 19 percent internal rate of return, after tax (IRR).

A. Tax Incentives

Tax incentives improve project economics by reducing the effective cost of capital investment by decreasing the tax liability generated by a project and/or improving the cash flow to equity holders. This section considers the effects of investment tax credits, excise tax credits, accelerated depreciation/expensing, and tax exempt debt, all of which are provided under existing tax law.

1. Investment Tax Credit

An investment tax credit ("ITC") provides a taxpayer with a credit against income tax payable based on the amount of the taxpayer's investment in eligible projects. An ITC can stimulate investment by reducing the effective cost of a capital project.

Method of Analysis: Scully Capital modeled the ITC incentive based on the ITC in EPAct. Specific assumptions include:

16 Assumptions and results of the Reference Plant analysis are provided in Chapter 3.
17 The crude-equivalent price is obtained by dividing the fuel price by 1.3.
18 The FT fuel price quoted includes the cost of crude and the cost to refine it.

- **Tax Credit Rate:** The analysis assumes that a 20 percent ITC is applied over the gasification portion of plant (which represents approximately 30 percent of plant costs).[19]
- **Depreciation Effects:** To avoid double counting the tax credit and tax depreciation expense taken on the portion of the asset funded by the tax credit, Scully Capital reduced the depreciable tax basis by an amount equal to the value of the ITC.
- **Tax Loss Appetite:** For simplicity, the analysis assumes that any tax loss or tax credit generated can be utilized by one of the sponsors of the project in the year the loss or credit is generated.

Impact Analysis: Based on the total plant cost in the Reference Plant ($3.27 billion), Scully Capital determined that the project would be able to use approximately $181 million in tax credits. (Exhibit 3.7 provides the sources and uses of funds for the Reference Plant.), The ITC offsets 6 percent of the total sources needed to fund the project. Based on the above assumptions, the resultant price of FT diesel is $67 ($52 CEP) per barrel, a reduction of 8 percent from Reference Plant results. The benefit of the ITC is offset slightly by increased tax liability from reduced depreciation expense.

Budgetary Impact: The budgetary impact for the incentive over the 10-year budget window would be approximately $141 million, while the total cost would be approximately $109 million. Total cost is lower than the 10-year budget window cost because the decreased depreciation expense from the reduced depreciable base increases the tax liability over the life of the project.

"Power of the Tool": ITCs stimulate investment by reducing the effective cost of a capital project, assuming that the sponsors can utilize the tax impact in the year the effect is created, although the benefit of the ITC is offset slightly by increased tax liability from reduced depreciation expense in the current year and future years. The budgetary impact of ITCs is on a dollar-for-dollar basis, making it an expensive tool for the government. Importantly, ITCs, like some other tax Incentives, have only a limited impact on a project's creditworthiness.

Overall, ITCs are somewhat effective in addressing high capital costs and the potential for rising construction costs because they buy down the cost of a project, but they are expensive to the government, offer little leverage to project sponsors, and enhance the creditworthiness of a project only to the extent they enhance cash flows.

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[19] The gasification portion of the plant includes the gasifiers and gas cleanup equipment, as well as a pro-rata share of contingency, balance of plant, and design costs based on the percentage that gasifiers and gas cleanup equipment represent of the total plant cost.

2. Excise Tax Credit

Under Internal Revenue Code (U.S. Code Title 26) Subtitle F and Chapter 65-B, the government imposes a tax on refined petroleum products which is ultimately paid by the consumer in the form of higher transportation fuel prices. An excise tax credit would effectively reduce or eliminate the tax paid by refiners, enhancing the competitive position of FT fuels compared to other fuels that are taxed. Keying off the current excise tax credit for alternative fuels, Scully Capital modeled three excise tax credit levels: 10 cents per gallon of fuel ($4.20 per barrel), 25 cents per gallon, and 50 cents per gallon.

Method of Analysis: When considering the results, it is important to note that the Congress is considering many different proposals that utilize an excise tax credit. Some proposals decrease the level of tax credit as the price of crude oil increases and others propose to limit the total amount of tax credit available to a specific plant, while still other proposals include a cap on the total dollar amount of tax credit provided to the industry. Reflecting these possible variations, Scully Capital analyzed three different excise tax credit levels over two different time horizons. Specific assumptions in the analysis of excise tax credits include:

- **Tax Credit Rate:** The analysis assumes three different excise tax credits per gallon of fuel: 10 cents, 25 cents, and 50 cents. The analysis assumes that the excise tax credit does not change with inflation.
- **Length of Tax Credit Effects:** Present law and proposed legislation offer a range of lifetimes for excise tax credit benefits. Scully Capital analyzed the effects of this tax credit for 5 and 10 years of production.
- **Tax Loss Appetite:** As with the ITC, Scully Capital assumes that any tax loss or tax credit generated can be utilized or monetized by one of the sponsors of the project in the year the loss or credit is guaranteed.

Impact Analysis: Observations on the impact of each excise tax credit level on the prospects of a project are provided below:

- **10 Cent Tax Credit Level:** The analysis indicates that the resultant price of FT fuels will be $70 (CEP: $54) per barrel for a 5-year tax credit and $68 (CEP: $52) per barrel for a 10-year tax credit. Thus, the 10 cent per gallon excise tax credit can provide a 4 percent and a 6 percent decrease in FT fuel price from the Reference Plant, respectively, for a 5-year and 10-year tax credit.
- **25 Cent Tax Credit Level:** The analysis indicates that the resultant price of FT fuels would be $65 (CEP: $50) per barrel for a 5-year tax credit and $61 (CEP: $47) per barrel for a 10-year tax credit. Thus, the 25 cent per gallon excise tax credit can provide an 11 percent and a 16 percent decrease in FT fuel price from the Reference Plant, respectively, for a 5-year and 10-year tax credit. At the 10

cent and 25 cent tax credit levels, doubling the time available for the production to be eligible for the excise tax credit increases the benefit by 50 percent.

- **50 Cent Tax Credit Level:** With a 5-year excise tax credit at this level, the price for FT fuels would be $57 (CEP: $44) per barrel, a reduction of 22 percent from the Reference Plant. For the 10-year excise tax credit, the price of FT fuel would be $54 (CEP: $42) per barrel, or 26 percent lower than the Reference Plant. Notably, the benefit of the tax credit in the 10-year case is constrained by the need to maintain an adequate pre-tax debt service coverage level.

Based on the analysis of the 5-year excise tax credit, every 1 cent of excise tax credit per gallon (42 cents per barrel) reduces the FT fuel price by 31.7 cents (CEP: 24.4 cents) per barrel. For the 10-year excise tax credit, the analysis is more nuanced. For the 10 cent and 25 cent excise tax credit, every 1 cent of excise tax credit per gallon reduces the FT fuel price by 47.3 cents (CEP: 36.4 cents) per barrel. Scully Capital's analysis of the 50 cent excise tax credit over 10 years shows that for every 1 cent of excise tax credit per gallon, the FT fuel price decreases by only 37.7 cents (CEP: 29 cents) per barrel because of the need for sufficient project cash flows (before the effect of the tax credit) to maintain adequate debt service coverage ratios.

Budgetary Impact: The budgetary impact over the 10-year budget window and the total cost for the incentive for each excise tax credit are provided below:

- **10 Cent Tax Credit Level:** The budgetary impact and the total cost for 5 years is $150 million. For 10 years, the budgetary impact and the total cost is $318 million.
- **25 Cent Tax Credit Level:** The budgetary impact and the total cost for 5 years increases proportionately to $375 million. For 10 years, the budgetary impact and the total cost is $795 million.
- **50 Cent Tax Credit Level:** The budgetary impact and the total cost for 5 years is $751 million. For 10 years, the budgetary impact and the total cost is $1,591 million.

Excise tax credits reward production. Therefore, as production ramps up during the early years of operations, a co-production plant may not be able to utilize as much of the tax credit as would be available once steady state operations have been achieved. As a result, the budgetary impact for 5 years is less than half the amount for 10 years.

"Power of the Tool": Excise tax credits stimulate investment by effectively reducing or eliminating the tax paid by producers of alternative fuels, making these fuels more competitive with other fuels that are taxed. Excise tax credits arise only when qualifying investments actually produce qualifying products, and they create value for a project's sponsors to the degree they affect either cash flow (via tax savings) or revenue for the product (by raising price or demand). The fuel blender, not by the plant owner, takes the excise tax credits, and the blender pays the plant owner a higher price for the fuel because it benefits from the tax impact of the excise tax credits.

The budgetary impact of excise tax credits is on a dollar-for-dollar basis, making them an expensive tool for the government. Excise tax credits, unlike ITCs, do not assure off-take, however, as do rate basing, purchase agreements, and portfolio standards. Overall, excise tax credits can be quite effective in addressing high variable costs (e.g., for feedstocks), but their high cost to the government, provision of little financial leverage, and limited capacity to enhance the creditworthiness of a project limit their effectiveness and cost-effectiveness. Excise tax credits *appear* to be effective because more plants will be ordered with them, but this outcome is due more to the *level* of the subsidy they may provide than the inherent cost-effectiveness of this tool.

3. 50 Percent Immediate Expensing of FT Equipment

Expensing of equipment can be classified as an accelerated depreciation incentive. Under current tax laws, the FT portion of a co-production plant will be depreciated for tax purposes over a 10-year period. An accelerated depreciation incentive serves to shorten the life of this asset class, allowing greater deductions for tax purposes during the early years of the project. This incentive reduces the project owner's taxes in the early years of the project, but results in an increased tax liability after the asset is fully depreciated. A 50 percent immediate expensing incentive would depreciate 50 percent of the cost of the FT equipment in the first year and depreciate the remaining 50 percent of the cost under current tax law (i.e., over 15 to 20 years, depending on the asset category).

Method of Analysis: Specific assumptions include:

- **Depreciation Schedule:** Fifty percent of the FT equipment is expensed in the first year and the remaining 50 percent is depreciated on a 10-year Modified Accelerated Cost Recovery System ("MACRS") schedule. The total cost of the FT equipment is estimated to be in the range of $370 million.
- **Tax Loss Appetite:** As with tax incentives analyzed earlier, Scully Capital assumes that any tax loss generated could be utilized by one of the sponsors of the project in the years it is realized.

Impact Analysis: The above assumptions result in a price of FT fuel of $72 ($55 CEP) per barrel, a 1 percent reduction in the price per barrel. While the FT equipment represents 11 percent of the total uses of funds, the acceleration of the expensing of the equipment does not significantly change the tax liability on a present value basis.

Budgetary Impact: The budgetary impact over a 10-year budget window for the incentive is estimated at $20 million. Since alternate depreciation schedules change the timing of the cash flows, but not the aggregate tax liability, the total cost to the government in nominal terms is zero.

"Power of the Tool": 50 percent immediate expensing of FT equipment reduces the project owner's taxes in the early years of the project, but results in an increased tax liability after the asset is fully depreciated. (Tax levels rise after deductions for depreciation are exhausted or completed — whether the depreciation is accelerated or normal.) This incentive creates value for a project's sponsors only if the sponsors can utilize the tax effect it creates. The value it creates is limited, as well, because the tax liability increases after the asset is fully depreciated. Because the aggregate tax liability is unchanged over the life of the useful life of the asset, the total cost to the government on a present value basis is zero. Overall, this incentive has limited effectiveness due to its small impact, unless it helps provide access to cheaper equity capital.

4. Investment Tax Credit with Expensing of Gasification and FT Module

This case combines the ITC and a modified accelerated depreciation schedule. The project could benefit from an ITC on the gasification section and immediate expensing of the entire costs of the gasification and FT modules.

Method of Analysis: Specific assumptions include:

- **Tax Credit Rate:** As with the ITC analysis, Scully Capital applies a 20 percent ITC over the gasification portion of plant (approximately 30 percent of plant costs).
- **Depreciation Effects:** Also as with the ITC analysis, Scully Capital deducts an amount equal to the value of the ITC from the depreciable basis.
- **Depreciation Schedule:** The analysis expenses in the first year 100 percent of the FT equipment and 100 percent of the remaining capital base (after deducting for the ITC) of the gasification section. The first-year expensing of the FT equipment and the gasification section totals approximately $1,095 million.
- **Tax Loss Appetite:** The expensing of equipment creates a large negative tax liability. The ability of investors to take advantage of this liability is an integral assumption in calculating the benefits from the incentive.

Impact Analysis: The above assumptions result in a price of FT fuel of $62 ($48 CEP) per barrel, a price reduction of 15 percent compared with the Reference Plant.

Budgetary Impact: The budgetary impact for this incentive reflects the combination of the effects of the ITC and accelerated depreciation. The ITC decreases the depreciable base of the plant, which increases the tax liability of the project, while expensing decreases tax liability in the short term, but increases tax liability over the remainder of the project. As a result, the budgetary impact of the combined incentive over a 10-year budget window is $194 million and the total cost of the incentive is approximately $87 million.

"Power of the Tool": This incentive package combines two tax benefits that address different parts of the co-production plant: ITC (for the gasification unit) and accelerated depreciation (for the gasification and FT units). Accelerated depreciation merely shifts forward in time tax deductions for plant costs, so the budget cost is minimal. Investment tax credits enhance equity returns well because they can be taken early (during construction even), and they have the effect of reducing equity needed. Note that because they reduce equity, depreciation is not allowed on the cost of the plant offset by the ITC, so depreciation is then calculated over the balance of the plant or system cost (total cost - ITC). The combination simultaneously increases and decreases the tax liability of the project short term, and the budget scoring is greater than the total cost of the combination because government recoups revenues outside the 10-year budget window. The ability of investors to take advantage of this liability is an integral assumption in calculating the benefits from the incentive, unless it helps provide access to cheaper equity capital.

5. <u>Tax-Exempt Debt</u>

Owners of corporate bonds pay Federal tax on bond interest. In limited situations, though, companies can issue corporate bonds on a tax-exempt basis. When corporations, through a tax-exempt issuer, issue tax-exempt debt, the investors in the debt do not have to pay taxes on their interest income from these bonds. Hence, they demand a lower rate of return on the bonds. This case analyzes the impact of utilizing tax exempt debt for financing the debt portion of the project's capital structure.[20]

Method of Analysis: Specific assumptions include:

- **Interest Rate:** Based on comparisons with similarly rated structures, Scully Capital assumes an interest rate on the debt of 5.5 percent. This interest rate is approximately 140 bps higher than the rate for "AAA" tax-exempt municipal bonds (as of December 2006).
- **Depreciation Schedule:** When corporations issue tax-exempt debt, they are required to use straight line depreciation schedules to depreciate their assets. Straight line depreciation increases their tax liability in the short term and decreases their tax liability in the long term, which on a present value basis decreases the cash flow to equity.

Impact Analysis: Based on the above assumptions, the price of FT fuels is $71 ($55 CEP) per barrel, a reduction of 3 percent from Reference Plant results. Exhibit 6.6 illustrates the potential sources and uses of the tax-exempt debt scenario.

[20] Alternative minimum tax considerations have been excluded from this analysis.

Exhibit 6.6: Sources and Uses Statement for Tax-Exempt Debt

SOURCES AND USES OF FUNDS ($000)

Coal Gasification with Co-Production Plant

Reference Case with Tax Exempt Debt

USES		SOURCES	
Facility Costs		**Gross Funding Requirements**	$ 3,107,049
Solids Handling	$ 166,616		
Air Separation Unit	261,673		
Gasification	470,533	Equity	932,115
F-T Liquids Area + Refining	369,650	Equity %	30%
Power Block	296,650		
Gas Cleanup/Polishing	300,197	Debt	2,174,934
Carbon Sequestration Equipment		Debt %	70%
- Compression	-		
- Transportation, Storage, and Monitoring	-		
Balance of Plant	352,601		
Owner's Contingency	110,896		
License Fees & Startup Costs	92,209		
Design Costs	190,891		
Subtotal - Facility Costs	2,611,915		
		Debt Composition	
Financing Costs			
		Tranche A	2,174,934
Development Costs	54,248		100%
Closing Costs	50,000		
Credit Subsidy Premium	-		
Debt Service Reserve Fund	106,174		
Capitalized Interest	284,712		
Subtotal - Financing Costs	495,134		
Gross Funding Requirements	**$ 3,107,049**	**Total Funds Drawn**	**$ 3,107,049**

The benefit from decreased interest rates is offset by increased tax liability from reduced interest deductions and decreased depreciation expense. The lower interest rate decreases the capitalized interest and debt service reserve fund, causing the overall uses of funds to decrease to $3.11 billion from $3.27 billion in the Reference Plant.

Budgetary Impact: The cost to the government for this incentive is a combination of (1) a decrease in tax revenue from taxable interest payments to a bond holder if the incentive is not present and (2) an increase in tax revenue during the initial years from reduced depreciation in the earlier years. On this basis, the budgetary impact over the 10 Year Budget Window is $325 million; it is $643 million over the life of the project.

"Power of the Tool": Tax-exempt debt has a high cost and relatively small benefits, and project sponsors or owners must be able to qualify for tax-exempt debt. The benefit from decreased interest rates is offset by increased tax liability from reduced interest deductions and decreased depreciation expense. Moreover, the benefit of these tax incentives depends on the ability of project sponsors to use tax credits and tax losses to offset their tax liability.

Summary of Tax Incentive Analysis

Some tax incentives, such as investment tax credits and accelerated depreciation, create incentives for investment by decreasing the capital cost of a plant, while incentives such as excise tax credits create incentives for production by improving the economics of production. Recent legislative proposals would link production incentives to the price of crude oil to provide support to a project when the price of oil is low, but do *not* provide support in a high-priced crude oil market. The benefit of all tax incentives depends crucially on the ability of project sponsors to use tax credits and tax losses to offset their tax liability. Exhibit 6.7 provides a summary of the tax incentive analysis discussed in this section.

Exhibit 6.7: Summary of Analysis of Tax Incentives

Type of Incentive	FT Diesel Price per Barrel	Crude Equivalent Price per Barrel	Percentage Change from Reference Case	Budget Impact ($ millions)	Total Cost to Taxpayer ($ millions)
Investment Tax Credit					
20%	$ 67	$ 52	8%	$ 129	$ 109
20% + Expensing	62	48	15%	194	87
Excise Tax Credit					
5 Years Production					
10 cent	70	54	4%	150	150
25 cent	65	50	11%	375	375
50 cent	57	44	22%	751	751
10 Years of Production					
10 cent	68	52	6%	318	318
25 cent	61	47	16%	795	795
50 cent	54	42	26%	1,591	1,591
50% Expensing of FT Equip.	72	55	1%	20	-
Tax Exempt Debt	$ 71	$ 55	3%	$ 325	$ 643

The budgetary impact of tax incentives is calculated on the cash flow over a fixed period of time (i.e., on a dollar-for-dollar basis). The cost of credit incentives, on the other hand, is largely based on the probability of default, which is relatively unlikely; thus, the cost of credit incentives is substantially less than 100 percent of the amount of credit provided. Hence, in general, tax incentives tend to be more expensive to the government than credit incentives. However, some people believe that tax incentives are easier to administer and have lower administration costs.

The benefits of tax incentives on the price of FT fuels can be small, as in the case of 50 percent expensing of FT equipment (1 percent benefit), or large, as in the case of 50 cent excise tax credits over 10 years (26 percent benefit). While, in general, the level of benefit and the cost of tax incentives are correlated and linear, tax exempt debt has a high cost (columns 5 and 6) and relatively small benefits (column 4).

B. Loan Guarantees

The structure of loan guarantees for capital-intensive projects can vary from program to program and will vary from project to project within a program. Some loan guarantees will cover the entire debt of a project, while other loan guarantees will apply to a portion of the debt, and the risks they cover will vary from project to project. DOE's loan guarantee program guidelines state that DOE prefers strongly to limit loan guarantees to 80 percent of a debt instrument and that in no case will DOE guarantee 100 percent of either a debt instrument or the entire debt of a project.

Under the Federal Credit Reform Act (1990), a credit subsidy premium paid at financial closing pays for the fiscal backing for each loan guarantee. The government calculates the credit subsidy premium based on an in-depth credit review of the project; the credit subsidy premium is approximately the present value of the "default probability" amount, net of recovery. The credit subsidy premium can be paid by using appropriated agency funds, by the applicant seeking the loan guarantee, or by a third party. The agency deposits credit subsidy payments in a special fund held by the Department of the Treasury to back, on a portfolio basis, all loan guarantees issued by that agency in the event of one or more defaults on guaranteed loans.

A credit review, like the review of a mortgage application, involves an assessment and verification of a number of important factors focused on the cash flow coverage for a project's debt payments. These factors include the level of equity invested, the outlook for revenues, the management team's track record, the technical viability of the project, the project's competitive market position, additional collateral, and the robustness of key agreements (e.g., the EPC contract, feedstock supply agreements, and insurance). During the credit review process, lenders and rating agencies (e.g., S&P, Moody's, Fitch) compare the prospects of the project's prospective debt obligations to other, known debt instruments (e.g., AAA-rated government debt, AA or A-rated corporate bonds, BBB-rated project debt, sub-prime debt). Each credit rating category carries expected default rates based on continuous reviews by the rating agencies relative to various economic factors. For example, the rating agencies performed an in-depth reassessment of the power sector following the merchant power collapse of 2002, which featured the bankruptcies of Enron, Calpine, and other power companies. Now, the rating agencies require contractual power purchasers ("off-takers") to have stronger balance sheets to improve the credit ratings of power projects. For loan guarantees on such power projects, a better credit rating would translate into a lower credit subsidy premium. As noted in Chapter 3, Scully Capital assumes that, benefiting from a 15-year purchase agreement from a creditworthy counterparty, a Reference Project has an underlying rating of BB and medium recovery prospects. The counterparty to the 15-year purchase agreement could be a private entity, a state or local government, or a Federal agency. Notably, the budget analysis of incentives does not assume that the counterparty is a Federal agency. The added assumption of the Federal government as a counterparty would add significantly to the estimate of budgetary impacts.

This section analyzes three of the many different ways for the Federal government to structure a loan guarantee for a co-production project. In the first scenario, a loan guarantee applies to all of a project's debt and the agency providing the guarantee uses available budget authority to fund the credit subsidy premium. In the second scenario, the agency provides a loan guarantee for all of a project's debt and the applicant pays the credit subsidy premium *from equity* ("self-pay"). In the third scenario, which also is on a "self-pay" basis, the Federal government guarantees 80 percent of the debt and the remainder of the debt (i.e., the un-guaranteed portion) is amortized in step with the guaranteed portion. The analysis of these three cases is presented below.

Option A: Guarantee of 100 percent of project debt and payment of the credit subsidy premium using agency budget authority

Method of Analysis: Scully Capital analyzed this loan guarantee incentive based on a conventional loan guarantee structure similar to that used in the Maritime Administration's Title XI loan guarantee program. The structure assumed in this analysis can be accommodated under the statutory language of EPAct. Specific assumptions include:

- **Debt-to-Equity Ratio (D/E ratio):** The Reference Plant has a D/E ratio of 70:30. The level of debt increases to 80 percent of project cost with this loan guarantee.
- **Loan Guarantee Coverage of Debt:** The loan guarantee is assumed to cover 100 percent of the project debt, reducing to approximately zero the exposure of the lender to default.
- **Length of Debt:** The analysis incorporates a final maturity assumption of 30 years after debt issuance (versus 15 years in the Reference Plant). Given an assumed construction time of 3 years and an extended interest capitalization period beyond the construction period of 1 year, the amortization time for the loan increases to 26 years, reflecting the 30-year term available in EPAct loan guarantees and a 4-year construction period.
- **Interest Rate:** The analysis assumes an interest rate of 60 basis points ("bps") over the LIBOR (London Interbank Offered Rate) fixed swap rate, which at the time of this analysis equated to approximately 100 bps above comparable length U.S. Treasury Bonds.[21] This assumption results in an all-in interest rate of 6 percent for project debt.
- **Credit Subsidy Cost:** Under this scenario, the applicant would not have to pay the credit subsidy premium, as these funds are assumed to be appropriated.

[21] Based on Scully Capital's recent involvement in a large project finance Federal loan guarantee for a Department of Transportation project.

The approximation of credit subsidy costs is based on analyses of existing Federal credit programs and Scully Capital's prior experience in credit loss financial modeling.

- **Credit Rating and Recovery Prospects:** Based on the results of extensive interviews and assuming an adequate quality of off-takers, Scully Capital estimates that the project's credit strength (absent the loan guarantee) would fall in the 'BB' credit rating range (one rating level below investment grade) with medium recovery prospects.[22]

Impact Analysis: Based on the above assumptions, the resultant price of FT diesel is $51 ($39 CEP) per barrel, a reduction of 30 percent from Reference Plant results. The borrower would benefit not only from decreased interest rates, but also from an increased debt amortization period (26 years versus 15 years for the Reference Plant) and from an increased debt portion in the project's financing of 80 percent (which reduces the weighted average cost of capital). In addition, lenders more readily supply debt financing for the project because of the assurance provided by the long-term off-take agreement and the loan guarantee, which combine to largely manage market risk.

Exhibit 6.8 presents the sources and uses statement for this incentive. This analysis demonstrates that lower interest costs, a longer amortization period, and increased leverage provide compelling economic benefits to the project sponsor. In addition, despite increased leverage, the debt service reserve fund and capitalized interest expense decrease from the Reference Plant. These decreases reduce the total uses of funds from $3.27 billion in the Reference Plant to $3.17 billion for a facility with a capital cost (or "overnight capital cost") of $2.611 billion.

[22] Scully Capital based this approach on an analysis of publicly available studies regarding the default and recovery prospects of project finance loans.

Exhibit 6.8: Sources and Uses Statement for Loan Guarantee — Option A

SOURCES AND USES OF FUNDS ($000)

Coal Gasification with Co-Production Plant

Reference Case with Loan Guarantee - Option A

USES		**SOURCES**	
Facility Costs		**Gross Funding Requirements**	$ 3,170,420
Solids Handling	$ 166,616		
Air Separation Unit	261,673		
Gasification	470,533	Equity	634,084
F-T Liquids Area + Refining	369,650	Equity %	20%
Power Block	296,650		
Gas Cleanup/Polishing	300,197	Debt	2,536,336
Carbon Sequestration Equipment		Debt %	80%
- Compression	-		
- Transportation, Storage, and Monitoring	-		
Balance of Plant	352,601		
Owner's Contingency	110,896		
License Fees & Startup Costs	92,209		
Design Costs	190,891		
Subtotal - Facility Costs	2,611,915		
		Debt Composition	
Financing Costs			
		Tranche A	2,536,336
Development Costs	54,248		100%
Closing Costs	50,000		
Credit Subsidy Premium	-		
Debt Service Reserve Fund	95,407		
Capitalized Interest	358,850		
Subtotal - Financing Costs	558,505		
Gross Funding Requirements	**$ 3,170,420**	**Total Funds Drawn**	**$ 3,170,420**

Budgetary Impact: Under the project's assumed credit quality, the Federal agency would have to obligate $188 million in appropriated funds as the expected credit subsidy premium for the loan guarantee. This amount represents a credit subsidy cost of 7.4 percent on the loan amount, recognizing the potential for recoveries in default. (The Federal government's senior position in default enhances recovery prospects.)

Option B: Guarantee of 100 percent of project debt and self-payment by the project sponsor of the credit subsidy premium

Method of Analysis: In addition to the stated assumptions in Option A, this scenario assumes that no budget authority exists for the Federal agency issuing the loan guarantee to pay the credit subsidy. Instead, the project sponsors fund the credit subsidy premium payment through equity or subordinate debt.

Impact Analysis: Incorporating the assumptions detailed above results in a price for FT fuel of $60 ($46 CEP) per barrel, a reduction of 18 percent from the Reference Plant. The borrower benefits from decreased interest rates, decreased weighted average cost of capital, increased leverage, and an increased debt amortization period of 26 years.

In addition, lenders more readily supply debt financing for the project because of the assurance provided by the long-term off-take agreement and the loan guarantee, which combine to largely manage market risk. To offset the expected loss to the government, the applicant would have to pay a credit subsidy premium of approximately $188 million for the loan guarantee. The credit subsidy is about 7.4 percent of the guaranteed loan. Exhibit 6.9 presents the sources and uses statement for the Option B loan guarantee.

Exhibit 6.9 displays the change in the D/E ratio to 76:24 from 80:20 in Option A and 70:30 in the Reference Plant. The equity percentage increases by 4 percentage points compared with Option A due to the use of equity to fund the credit subsidy premium for the loan guarantee. Although the total uses of funds increases from the $3.27 billion in the Reference Plant to $3.36 billion, the FT fuel price declines because of decreased interest costs, a longer amortization period, and increased leverage, all of which offset the increased uses of funds.

Exhibit 6.9: Sources and Uses Statement for Loan Guarantee — Option B

SOURCES AND USES OF FUNDS ($000)

Coal Gasification with Co-Production Plant

Reference Case with Loan Guarantee - Option B

USES		**SOURCES**	
Facility Costs		**Gross Funding Requirements**	$ 3,358,109
Solids Handling	$ 166,616		
Air Separation Unit	261,673		
Gasification	470,533	Equity	821,773
F-T Liquids Area + Refining	369,650	Equity %	24%
Power Block	296,650		
Gas Cleanup/Polishing	300,197	Debt	2,536,336
Carbon Sequestration Equipment		Debt %	76%
- Compression	-		
- Transportation, Storage, and Monitoring	-		
Balance of Plant	352,601		
Owner's Contingency	110,896		
License Fees & Startup Costs	92,209		
Design Costs	190,891		
Subtotal - Facility Costs	2,611,915		
		Debt Composition	
Financing Costs			
		Tranche A	2,536,336
Development Costs	54,248		100%
Closing Costs	50,000		
Credit Subsidy Premium	187,689		
Debt Service Reserve Fund	95,407		
Capitalized Interest	358,850		
Subtotal - Financing Costs	746,194		
Gross Funding Requirements	**$ 3,358,109**	**Total Funds Drawn**	**$ 3,358,109**

Budget Score: Despite the 7.4 percent credit subsidy cost, this incentive has a zero net cost to the government because the project developer (rather than the government) pays the credit subsidy cost. Hence, the budget score for the incentive is zero.

Option C: Guarantee 80 percent of project debt and self-payment by the project sponsor of the credit subsidy premium

Method of Analysis: Beyond the assumptions in Option B ("self pay" credit subsidy loan guarantee over entire debt), Option C assumes that the loan guarantee covers 80 percent of the debt. The other 20 percent of the debt would not benefit from the loan guarantee and would have an amortization schedule identical to that of the 80 percent portion. Moreover, the un-guaranteed portion of the debt could not be "stripped" from the guaranteed portion and would be subordinate in lien status to the guaranteed portion. Because the lender would own both the guaranteed portion and the un-guaranteed potion of the debt, the lender would be exposed to a degree of project risk. As in Option B, the project sponsor funds the credit subsidy premium payment through equity investment or subordinate debt.

A split debt structure affects the interest rates associated with the project's debt adversely. Scully Capital estimated the interest rates for the guaranteed and un-guaranteed portions based on conversations with project finance lenders, who indicated the difficulty in obtaining long-term subordinate debt under the terms outlined above. For the 80 percent of the debt that is guaranteed, the analysis assumes that the fixed rate would be 75 bps greater than in Option A or Option B, implying an interest rate of 6.75 percent. The remaining 20 percent would be priced at 820 bps over the LIBOR rate, or 13.6 percent. The resulting blended cost of capital for the debt portion is calculated to be 8.12 percent. The increased interest rate for the 80 percent of the debt that is guaranteed (compared with the rate in Option A and Option B) occurs because of the unique nature of the credit instrument that does not allow stripping of the guaranteed and un-guaranteed securities. Interestingly, the effective cost of debt capital would be higher under this option than the cost of debt capital in the Reference Plant because the un-guaranteed debt carries a sharply higher interest rate and the guaranteed portion carries a higher interest rate compared with Reference Plant debt, as well as the debt of the plants in Options A and B. The un-guaranteed debt is effectively subordinate to the guaranteed debt, resulting in a quasi-equity risk profile for which lenders will demand a higher interest rate.

Since the guarantee in Option C covers 80 percent of the debt, the debt guaranteed in Option C is smaller than the debt guaranteed in Options A and B. While the guaranteed debt is reduced, the collateral securing the debt is the same. As a result, the recovery rate in an event of a default situation increases on the guaranteed portion.[23]

Impact Analysis: Based on the above assumptions, the resultant price of FT fuel is $63 ($48 CEP) per barrel, a reduction of 14 percent from the Reference Plant results. Unlike the other options, the project sponsor would not benefit from a reduced interest rate on the project's debt. However, the project still benefits from increased leverage

[23] The adjustment involved assuming that the recovery amount would be constant, but applied over a smaller outstanding loan.

and a longer debt amortization period. In addition, lenders more readily supply debt financing for the project because of the assurance provided by the long-term off-take agreement and the loan guarantee, which combine to largely manage market risk. To offset the expected loss to the government, the project sponsor would pay a credit subsidy premium for the loan of approximately $129 million, or 6 percent on the loan amount. The credit subsidy cost is lower than in Option B because of the smaller amount of guaranteed debt *and* the higher recovery rate.

Exhibit 6.10 presents the sources and uses statement for this incentive. This exhibit shows that the D/E ratio changes to 77:23 from the starting assumption of 80:20 in Option A and 70:30 in the Reference Plant. The equity percentage increases 3 percent compared to Option A, but less than in Option B (4 percent). The effective D/E ratio is higher in Option C than Option B because of the smaller equity-funded credit risk premium. As with the loan guarantee in Option B, the FT fuel price is reduced, even though the total uses of funds increases from $3.27 billion in the Reference Plant to $3.46 billion.

Exhibit 6.10: Sources and Uses Statement for Loan Guarantee — Option C

SOURCES AND USES OF FUNDS ($000)

Coal Gasification with Co-Production Plant

Reference Case with Loan Guarantee - Option C

USES		SOURCES	
Facility Costs		**Gross Funding Requirements**	$ 3,464,504
Solids Handling	$ 166,616		
Air Separation Unit	261,673		
Gasification	470,533	Equity	795,724
F-T Liquids Area + Refining	369,650	Equity %	23%
Power Block	296,650		
Gas Cleanup/Polishing	300,197	Debt	2,668,781
Carbon Sequestration Equipment		Debt %	77%
- Compression	-		
- Transportation, Storage, and Monitoring	-		
Balance of Plant	352,601		
Owner's Contingency	110,896		
License Fees & Startup Costs	92,209		
Design Costs	190,891		
Subtotal - Facility Costs	2,611,915		
		Debt Composition	
Financing Costs			
		Tranche A	2,135,025
Development Costs	54,248		80%
Closing Costs	50,000		
Credit Subsidy Premium	128,528	Tranche B	533,756
Debt Service Reserve Fund	124,563		20%
Capitalized Interest	495,250		
Subtotal - Financing Costs	852,590		
Gross Funding Requirements	**$ 3,464,504**	**Total Funds Drawn**	**$ 3,464,504**

The lower credit subsidy premium in Option C compared with Option B reduces the contribution from equity holders. The decreased credit subsidy premium can be traced to the collateral securing a smaller guaranteed loan amount. As a result, the price of FT fuel decreases compared to the Reference Plant because increased leverage and an increased amortization period offset the increased uses of funds and higher interest cost of debt.

Budget Score: This incentive was modeled as a zero net cost to the government because the project developer, rather than the government, pays the credit subsidy cost. Hence, the budget score for the incentive is zero.

Summary of Loan Guarantee Analysis

The options outlined above overview the spectrum of methods for implementing loan guarantees under EPAct. The analysis demonstrates that credit incentives increase the likelihood that a project will be undertaken and provide significant impact on the pricing of FT fuels, while maintaining a constant rate of return for investors. As Exhibit 6.8 illustrates, under a non-recourse financing structure and with the allocation of risks specified earlier, loan guarantees provide a 14 percent to 30 percent benefit depending on the structure of the guarantee and depending on whether the project sponsor or the government pays the credit subsidy premium. Different allocations of risk would yield different FT fuel prices and credit subsidy premiums. For example, all three scenarios assume placement of a substantial long-term off-take agreement; the terms of a loan guarantee for a project without such an agreement would likely be less favorable to the project sponsor. Loan guarantees increase financial leverage in the project, lengthen the debt repayment time frame, and decrease the cost of capital.

The eventual structure of a loan guarantee affects the benefit it provides, as does the ability of DOE to use appropriated funds to pay credit subsidy premiums. Exhibit 6.11 provides a summary of the results of the analysis of the three loan guarantee options.

Exhibit 6.11: Summary of Loan Guarantee Analysis

Type of Loan Guarantee				Price Analysis			
Option	Government / Self-Pay Credit Subsidy	Debt Guarantee Percentage	Total Debt ($ millions)	FT Diesel Price per Barrel	Crude-Equivalent Price per Barrel	Change from Reference Case	Budget Impact ($ millions)
Option A	Government	100%	$ 2,536	$ 51	$ 39	30%	$ 188
Option B	Self-Pay	100%	2,536	60	46	18%	-
Option C	Self-Pay	80%	$ 2,644	$ 63	$ 48	14%	$ -

*For credit incentives, budget impact is equal to the total cost to taxpayers.

The price of FT fuel from a project that benefits from a loan guarantee incentive varies between $51 (CEP: $39) per barrel and $63 (CEP: $48) per barrel. A project with an

Option B "self-pay" loan guarantee benefits 40 percent (12% / 30%) less from a project with an Option A loan guarantee. Similarly, the reduction in percentage of the debt guaranteed from Option B to Option C reduces the benefit of a guarantee by an additional 22 percent (4% / 18%).

"Power of the Tool": Loan guarantees have a very favorable impact on product pricing, particularly if the sponsors have utilized a project finance structure. They have this effect by reducing interest rates, increasing the debt amortization period, increasing leverage in the project's financial structure, and reducing the weighted average cost of capital for the entire project. In addition, loan guarantees increase the likelihood that a project will be undertaken because they increase the likelihood that lenders will be repaid for project debt. The combination of loan guarantees with long-term off-take agreements largely manages market risk. Loan guarantees also permit the government to lever scarce incentive resources, enabling it to provide assistance to several times more projects than incentives that score for budget purposes on a dollar-for-dollar basis, such as tax credits.

The three loan guarantee options differ somewhat within this general picture. Compared with loan guarantee Options B and C, for example, Option A loan guarantees offer the greatest leverage for the project sponsor (80 percent debt versus 70 percent for the Reference Plant, 76 percent in Option B, and 64 percent in Option C), the lowest interest rates, a large lender pool, a strong secondary market for guaranteed loans, and a greater likelihood of enabling a project to go ahead — brought about by the combination of guarantees for 100 percent of project debt and government payment of the credit subsidy premium. The split debt structure in Option C adversely affects the pool of lenders, the availability of debt, the interest rates associated with the project's debt, and the weighted average cost of capital.

C. State Incentives

State incentives provide financial benefits directly (e.g., development grants, tax credits) or indirectly (e.g., by accelerating environmental or other regulatory clearances). A few state incentives may be critical to the genesis of a project or just very powerful, but most state incentives provide a smaller benefit than possible Federal incentives in dollar terms. While most current state benefits for projects that utilize coal target Integrated Gasification Combined Cycle (IGCC) facilities, many of the same incentives could be applied to coal co-production facilities. Possible state incentives that could be applied to co-production facilities are presented below:

- **Development Grants:** Many states provide grants in the range of less than $1 million to $10 million to facilitate the development of coal gasification projects, including co-production plants. While these grants may not make a measurable impact on the eventual price of FT fuel, they do provide a source of financing during the development process, which is early in the life of a project.

- **Investment Tax Credits (ITC)**: Some states provide an ITC, either on the coal gasification system or on the entire plant. In general, the value of these tax credits is lower than tax credits provided by the Federal government.
- **Property Tax and Local Tax Exemptions:** Many states provide exemptions from property tax, sales tax, and other local taxes for a period of time (e.g., five or ten years) for large projects in economically depressed areas. These tax exemptions provide an extra stimulus to the economics of the project.
- **Employment-Related Incentives:** One attraction of co-production plants is their capacity to create well-paying construction, manufacturing, and mining jobs. To promote job creation, states often provide incentives that decrease the cost of employing their citizens by reducing payroll taxes or by providing tax credits for every job created.
- **Streamlining Environmental Procedures:** State and local authorities can streamline regulatory processes associated with environmental clearances for a project and/or efficiently process applications for environmental clearances for a project. Supportive state and local authorities can decrease the time it takes to receive clearance by months or even years. In the opposite case, delays in the ramp-up of production raise capital carrying costs, directly reducing IRR or raising fuel prices.
- **Co-production Infrastructure and Liability Assumption:** Co-production facilities produce, as a by-product, carbon dioxide that potentially can be used for enhanced oil recovery (EOR) projects or other economic purposes. A state could create incentives for co-production projects by providing infrastructure to transport the carbon dioxide to oil fields that could use it or can create incentives for private investment in carbon dioxide transportation systems. The state would benefit from not only co-production products, but also from enhanced oil recovery and, simultaneously, permanent sequestration of the carbon dioxide generated by the co-production plant. A potential issue in building a carbon dioxide pipeline or EOR project is indemnification for damages associated with carbon dioxide leakage. State (or Federal) indemnification against carbon dioxide leakage from a carbon dioxide pipeline or from subterranean long-term storage could promote co-production projects. Indemnification could facilitate monetization of the value of carbon dioxide produced by a project, encouraging needed carbon dioxide sequestration in a carbon-constrained environment. Analysis of the potential cost and financial impacts of indemnification against carbon dioxide leakage was not a part of this project.
- **Purchase Agreements and Alternative Energy Incentives:** A state agency (e.g., the public utility commission, or PUC) may be able to authorize a local utility or transit system to purchase a co-production product (e.g., FT fuels, synthetic natural gas, electricity) through a long-term purchase agreement, providing a significant hedge against market risk to the project. A state could also mandate that co-production products (e.g., synthetic natural gas, electricity)

have preference in state markets or be used to meet state alternative energy goals, particularly if the carbon produced in their manufacture were sequestered.

- **Low-Interest Loans and Tax-Exempt Bonds:** States could provide low-interest loans to a co-production plant or facilitate issuance of tax-exempt bonds.
- **Research, Development, and Demonstration (RD&D) Funding:** Certain states promote future coal co-production plants by providing funding for RD&D that could improve technology. The funding can have as its ultimate goal improving clean coal technology or promoting the use of state coal reserves.
- **Cost Recovery and Utility Regulation:** While this powerful incentive is frequently thought of in conjunction with electricity production from IGCC plants, state agencies (e.g., PUCs) also can allow part or all of a coal co-production plant to become part of the rate base and earn a regulated return on investment. Some states also can allow an enhanced rate of return on investments in coal co-production projects.

Exhibit 6.12 provides an overview of state incentives applicable to coal gasification with co-production plants. This exhibit shows that Illinois has taken a leadership position in promoting coal-based co-production plants. Illinois provides incentives that encompass monetary benefits, streamlined regulatory processes, improved infrastructure, and sponsorship of long-term clean coal research. Other states with large coal reserves have also approved incentives to promote coal-based co-production. For example, Louisiana attracted a large Chinese co-production plant that may be built in state. In part because Texas and Illinois offered such state incentives as indemnification of a potential carbon dioxide pipeline from the plant to sites that can use it, DOE chose them as the finalists to be the home of the next-generation coal co-production plant, FutureGen. Thus, the application of state incentives in conjunction with Federal incentives can provide significant added benefit to project economics.

Exhibit 6.12: Overview of State Incentives[24, 25]

Incentive	Illinois	Indiana	Kansas	Louisiana	Minnesota	Ohio	Pennsylvania	Texas	Wyoming
Development Grants	√				√		√	√	
Investment Tax Credit	√	√	√	√					
Property Tax and Local Tax Exemption	√			√	√				√
Employment Related Incentives	√			√					
Streamling Environmental Procedure				√		√		√	
Co-Production Infrastructure and Liability Assumption	√							√	
Purchase Agreements / Alternative Energy Incentive	√		√		√	√	√		
Low Interest Loans	√					√	√		
Research, Development, and Demonstration Funding	√	√				√			
Cost recovery and utility regulation		√				√			

D. Other Incentives

Federal cost-sharing grants and purchase agreements do not fall into any of the categories analyzed above.

1. Federal Cost-Sharing Grants

Federal (or state) grants provide direct funding to a project, effectively decreasing their capital cost. In some cases, grants carry provisions for repayment, but the repayment terms may have significant flexibility and payments to the Federal government generally are made only after other investors have recouped their investments. The analysis considered two sizes and types of cost-sharing grants:

- Option A: A $200 million cost-share grant with and without repayment; and
- Option B: A $1.3 billion cost-share grant (representing 50 percent of the facility's hard costs), with and without repayment.

[24] K. Burke. "Integrated Gasification Combined Cycle Technology: State Incentives". National Conference of State Legislatures. November 2006.
[25] Keystone Center. "IGCC/CCS - Federal and State Incentives for Early Commercial Deployment." State Clean Energy and Environment Technical Forum. November 2006.

Option A: $200 Million Cost-Share Grant

This case models a $200 million grant both with and without repayment. A grant or loan of this size would help to fund development costs or front end engineering and design costs (termed "FEED"). Project development and FEED provide a basis to obtain additional funding from investors and lenders.

Method of Analysis: Assumptions include:

- **Depreciation Basis:** The case without repayment decreases the depreciable base by the amount of the grant.
- **Principal Payment:** The case with repayment assumes that the grant will be repaid over 20 years in equal installments, starting at the end of construction.

Impact Analysis: Based on the above assumptions, the price of FT fuel with no grant repayment is $69 ($53 CEP) per barrel. If repayment were required, the price of FT fuels would be $68 ($52 CEP) per barrel. This grant results in a reduction of 6 percent with no repayment and 7 percent with repayment. The lower price of FT fuel under a repayment scenario occurs because a depreciation expense can be taken against the grant amount, which is treated for tax purposes as a loan. Based on this analysis, it appears that the present value of tax benefits associated with the accelerated depreciation of the grant amount is greater than the present value of the principal repayments. Moreover, principal repayments on the cost-share are likely to be subordinate to other debt service payments, improving the credit profile of the senior debt. As a result, even if the principal (the grant) needs to be repaid, benefits resulting from the repayment obligation associated with the grant outstrip the financial advantages of a grant without repayment.

Budgetary Impact: The budgetary impact is equal to the grant amount, or $200 million, in the year obligated for disbursement (actual disbursement may differ). Budgetary impact is calculated in a 10-year window and money flows outside that window are not included. Thus, if a grant were repaid outside the 10-year window, repayment would not be included in the calculation of the budgetary impact.

Option B: $1.3 Billion Cost-Share Grant

This case models, with and without repayment, a $1.3 billion cost share grant of half of the hard costs of a facility. A cost share of this size is integral to the funding structure of the project.

Method of Analysis: Specific assumptions include:

- **Depreciation Basis:** As with Option A, the case without repayment decreases the depreciable base by the amount of the grant.

- **Timing of Cost-Share:** Unlike Option A, the case assumes that the cost share is provided in step with other funding sources.

Impact Analysis: Based on the above assumptions, the price of FT fuel with no grant repayment is $46 ($36 CEP) per barrel. If repayment were required, the price of FT fuels would be $49 ($38 CEP) per barrel. The price of FT fuel would be reduced by 36 percent without repayment and 32 percent with repayment. The impact of repayment is different in Option B: The no-repayment case achieves a lower price of FT fuel than the repayment case. In Option B, the present value of tax benefits associated with accelerated depreciation of the grant amount under the repayment case appears to be less than the present value of the principal payments.

Budgetary Impact: The budgetary impact is equal to the grant amount, or $1,306 million, in the year obligated for disbursement (actual disbursement may differ), an amount equivalent to 50 percent of the hard cost of the facility. As in Option A, if the grant were repaid outside the 10-year budget window, repayment would not be included in the calculation of the budgetary impact.

"Power of the Tool": Cost-sharing grants, both with and without repayment, have a favorable impact on product pricing, but they are expensive to the government. They have a positive effect because they effectively decrease the capital cost of projects and because, if they must be repaid, they hold the same position as subordinate debt on the project's balance sheet. Repayment terms also may be flexible. In some cases, grants with repayment may have an improved effect compared with grants without repayment because they are treated as loans for tax purposes, expanding the depreciable amount compared with a grant without repayment. For budget purposes, however, grants score on a dollar-for-dollar basis, and with respect to the creditworthiness of a project, grants have a limited effect in assuring repayment of project debt.

2. <u>Long-Term Purchase Agreements</u>

Under a long-term purchase agreement ("PA"), the Federal government, a state or local government agency, or another creditworthy counterparty would agree to purchase a pre-determined portion of a plant's output based on an agreed pricing mechanism. The ability of the plant owners to enter into a purchase agreement with a creditworthy off-taker, either private or public, that assures a revenue stream sufficient to meet debt payments, is a core assumption in the Reference Plant. In this application, a purchase agreement is not an incentive, but an integral part of the financial structure of a project. A long-term purchase agreement is important to enhancing the prospects of a coal-based co-production plant because it assures revenue to the project as long as the plant operates. An assured revenue stream reduces market risk by removing price volatility. As this section outlines, however, the terms and conditions of a PA can vary widely and a PA from a government agency can be constructed to function as an incentive. However, to the extent a Federal agency is the contracted counterparty under a PA, the budgeting cost (score) may be significant.

A PA can be structured in several ways to meet the needs of the project sponsor, lenders, or the off-taker, and the budgetary impact of a PA will depend on the risks that an off-taker assumes. The more the off-taker absorbs risk, the better the pricing on project debt (through lower interest rates) and the lower the IRR required by equity holders. Factors that can vary in the structure of a PA include:

- **Portion of the Plant's Output Covered:** The greater the percentage of output the off-taker obligates to purchase, the greater the leverage it has in crafting an agreement that meets its needs. Moreover, an agreement to purchase a larger percentage of production would decrease the risk to lenders and should decrease the price of project debt.
- **Take-or-Pay:** PAs can be structured so that the off-taker pays whether or not it buys the fuel. A take-or-pay agreement ensures a continuous cash flow, so the project can obtain more favorable debt terms.
- **Fixed Date:** Under date-certain contracts, payments begin on a certain date whether or not the product is physically delivered. The payments would begin on a fixed date and, if the product is not available, it would be delivered when the product is ready. In such circumstances, the off-taker would be able to receive discounts for future deliveries or some other benefit. A combined fixed date/take-or-pay contract could help reduce project completion risk and facilitate better terms for the debt.
- **Cost Pass-Throughs:** Most off-take contracts use this feature to enable a project to manage unexpected costs beyond its control. The contract allows the pass-through of extra costs via increased prices to the off-taker. Unexpected costs may arise, for example, from changes in regulations that increase costs to manage environment impacts of the project. Moreover, construction contracts also have cost pass-throughs for the price of commodities, such as steel and cement. The pricing of these commodities cannot be controlled by the contractor without a substantial premium, and they form a large portion of the cost of constructing the facility. As a result, the pass-through of changes in certain commodity prices often makes economic and financial logic. Pass-throughs decrease the risk that the debt and equity investors assume, and they may lead to lower FT fuel prices in the PA.
- **Pricing:** The pricing of delivered FT fuel can be structured to allocate input price and output price risk between parties. Allocation options include:
  - **Fixed Price Adjusted with Indexes:** In this pricing scheme, the base price of FT fuel would be fixed and then adjusted by appropriate indexes. The indexes can be either broadly defined, such as by a CPI or PPI index, or by an index that changes with a key variable cost. For a co-production plant, the significant input prices are for coal, chemicals (including catalysts), and labor. The output price can be calibrated to an index comprised of coal prices, chemical prices, and/or labor prices. This approach helps to provide a

consistent debt coverage level and helps to insulate the project from variable input costs. While, in general, a fixed price provides certainty for both the producer and the off-taker, it may not correlate with a substitute product (e.g., crude oil). As a result, it is possible for the price of FT fuel to be greater than or lower than the prevailing crude oil price of the spot market.

– **Based on Price of Oil with a Pre-Defined Price Floor:** The price of FT fuel can be based on the price of oil-based products (e.g., 10 percent below market price, $5 per barrel below market price) with a price floor. The price floor would insulate debt investors from the worst case scenario, while an off-take price below prevailing market conditions might make the project more viable politically. In this scenario, the equity investor would be taking a larger degree of the market price risk. The off-taker, on the other hand, would not benefit as much if crude prices increase significantly and might have spent a smaller amount through the project life cycle with a fixed price option.

– **Based on Price of Oil with a Pre-Defined Price Floor and Price Ceiling:** In this pricing scheme, the price of FT fuel would move within a band. Debt investors would be protected from downside price volatility in oil markets and, in exchange, the off-taker would receive some hedging benefit if prices increase.

The Reference Plant analysis assumes a PA structured to include a fixed price ($73 per barrel for FT fuels or $56 per barrel crude-equivalent), adjusted for indices and a take-or-pay contract with cost pass-through. Scully Capital determined that, with the technology and construction risk inherent in an early commercial co-production plant and volatility in crude oil markets, this option may provide a lower cost of capital for the project than other options. The lower cost of capital could translate into a lower FT fuel price. .

Method of Analysis: PAs can help obtain reasonable financing terms for the project and thereby decrease the cost of FT fuel to the off-taker. As noted earlier, the Reference Plant assumes a 15-year PA that would help the project obtain financing that is just below investment grade. For cases in which the off-taker is a Federal agency, Scully Capital computed the budgetary impact of the PA using two methodologies: one prescribed in OMB Circular A-11 and a cash outlay methodology adopted previously by Congressional Budget Office (CBO).

OMB Circular A-11 provides a mechanism for assessing the budgetary impact of a contract that obligates the Federal government to purchase goods and services for a multi-year period. In this methodology, the present value of cash outlays over the term of the contract represents the budgetary impact of the PA. This amount is scored at the time the obligation is made; it represents the amount of budget authority the Federal agency needs to assign to the project before it is able to sign the PA contract. Given the flat nature of the Treasury yield curve at the time of the analysis, Scully Capital used a 5.3 percent discount rate as specified in OMB Circular A-94 for analyses determining the present value of the cash outlays.[26]

The cash outlay methodology has been used previously by the CBO to determine the budgetary impact of a power purchase agreement (PPA) from a nuclear power plant. In the cash outlay methodology, the cash spent during the contract period is the budget authority the Federal agency needs to obtain before it is able to sign the PA contract.

Impact Analysis: PAs from creditworthy off-takers favorably influence the length of debt (debt tenor) and the cost of borrowing because they shift risk from the plant owner to the purchaser providing the PA. Based on feedback from the financial community, a well structured PA would be essential for realizing the financing assumptions embodied in the Reference Plant.

Budgetary Impact: The analysis showed that, using OMB Circular A-11 methodology, the budgetary impact of the PA for 100 percent of the Reference Plant's FT production is $6.8 billion and, using a cash outlay methodology, the budgetary impact of the PA is $10.4 billion. The OMB Circular A-11 methodology result is 34 percent lower than that of the cash outlay method. It is important to note that both the OMB Circular A-11 method and the cash outlay method require the obligation of budget authority substantially greater than the cost of building a Reference Plant.

"Power of the Tool": A long-term PA would significantly enhance the prospects of a coal-based co-production plant because it would assure revenue to the project as long as the plant operates. An assured revenue stream reduces market risk by removing off-take and price volatility as factors that jeopardize the repayment of project debt. PAs also favorably influence the length of debt and the cost of borrowing. Although the PA is a flexible tool that can be structured in a number of ways to meet the needs of the project sponsor, lenders, and the off-taker, PAs do not reduce technology and construction risks. PAs also are a very expensive option for the Federal government and other organizations that must report the long-term liability that the PA represents.

E. Two Combination Cases

This section presents the impact on the Reference Plant, which benefits from a purchase agreement, of a combination of several incentives that are authorized today. Two combination cases are considered. Combination Case 1 targets the floor price for crude oil when this study started: $33 per barrel. Combination Case 2 targets the current floor price of $40 per barrel.

[26] OMB Circular provides discount rates for 3, 5, 7, 10, 20, and 30-year time frames. Factoring in construction time and a 15-year PA, the appropriate discount rate to use in the analysis is 20 years, or 5.3 percent.

Method of Analysis: Both Combination Cases combine the following financial incentives:

- **Loan Guarantee Option B (see Section B):** This loan guarantee covers 100 percent of the project debt and the project sponsor pays the credit subsidy premium using equity or subordinate debt.
- **Excise Tax Credit:** In Combination Case 1, a 5-year, 50-cent-per-gallon excise tax credit (equivalent to $21 per barrel) is provided for the output of a project; this excise tax credit is the same as provided by SAFETEA-LU for alternative fuels. In Combination Case 2, the same excise tax credit is provided, but it is available for up to the first 10,000 barrels per day produced in a plant. These types and levels of tax credit are similar to proposals in Congress to encourage alternative transportation fuels.
- **State-funded Development Grant:** A state provides a development grant of $20 million to ensure that a co-production facility will be sited in that state. This grant provides funds to the project at an early stage of development when the project has not achieved financial close. The grant facilitates project development activities, including preliminary engineering, feasibility studies, site selection, and development of an off-take contract.

Importantly, the combination cases do not assume that a Federal agency is the customer (off-taker) under the PA. If one were, it would add to the budgetary cost of the government and would introduce the prospect of a loan guarantee being secured in part by Federal appropriations.

Impact Analysis: In Combination Case 1, the FT fuel price declines 41 percent compared with the Reference Plant price to $43.29 ($33.30 CEP) per barrel. This price is very close to the long-term price assumption for crude oil at the start of this project. By reaching this price, project sponsors are able to obtain financing for the project and to improve the terms of equity and debt financing. To obtain the Federal loan guarantee, the project sponsor funds a credit subsidy premium of $186 million, an amount equal to 7.4 percent of the total loan, from equity.

Exhibit 6.13 provides the sources and uses statement for Combination Case 1. The Reference Plant debt-to-equity ratio assumption is 70:30. The loan guarantee incentive permits greater leverage, so this analysis assumes an 80:20 debt-to-equity ratio, which decreases to 76:24 because of the requirement to fund the credit subsidy premium with equity. In the analysis of this Combination Case, upon incorporation of the $20 million state development grant, the debt percentage decreases slightly resulting in a debt-to-ratio of 75:24:1. Additionally, although the total usage of funds for Combination Case 1 increases from $3.27 billion in the Reference Plant to $3.35 billion, the fuel price decreases due to the impact of the combination of incentives.

Exhibit 6.13: Sources and Uses of Funds for Combination Case 1

SOURCE AND USES OF FUNDS ($000)

Loan Guarantee with 5-yr 50 cent Excise Tax & $20M Development Grant

USES		SOURCES	
Facility Costs		**Gross Funding Requirements**	$ 3,351,675
Solids Handling	$ 166,616		
Air Separation Unit	261,673		
Gasification	470,533	Equity	815,304
F-T Liquids Area + Refining	369,650	Equity %	24%
Power Block	296,650		
Gas Cleanup/Polishing	300,197	Debt	2,516,371
Carbon Sequestration Equipment		Debt %	75%
- Compression	-		
- Transportation, Storage, and Monitoring	-		
Balance of Plant	352,601		
Owner's Contingency	110,896		
License Fees & Startup Costs	92,209	Grant	20,000
Design Costs	190,891	Grant %	1%
Subtotal - Facility Costs	2,611,915		
		Debt Composition	
Financing Costs			
		Tranche A	2,516,371
Development Costs	54,248		100%
Closing Costs	50,000		
Credit Subsidy Premium	186,211		
Debt Service Reserve Fund	94,656		
Capitalized Interest	354,645		
Subtotal - Financing Costs	739,760		
Gross Funding Requirements	**$ 3,351,675**	**Total Funds Drawn**	**$ 3,351,675**

The results further show that the cash flow required to cover debt service is much lower for the Combination Cases than for the Reference Plant, primarily because of the impact of the excise tax credit.

In Combination Case 2, the FT fuel price declines 30 percent compared with the Reference Plant to $50.29 ($39.03 CEP) per barrel. This price is very close to the higher long-term price assumption for crude oil applied in 2007. By reaching this price, project sponsors are able to obtain financing for the project and to improve the terms of equity and debt financing. To obtain the Federal loan guarantee, the project sponsor funds a credit subsidy premium of $186 million, an amount equal to 7.4 percent of the total loan, from equity. Exhibit 6.14 provides the sources and uses statement for Combination Case 2.

Exhibit 6.14: Sources and Uses of Funds for Combination Case 2

SOURCE AND USES OF FUNDS ($000)

Loan Guarantee + 5-yr, 50 cent Excise Tax Credit up to 10,000 bpd + $20M Development Cost Grant

USES		SOURCES	
Facility Costs		**Gross Funding Requirements**	$ 3,351,675
Solids Handling	$ 166,616		
Air Separation Unit	261,673		
Gasification	470,533	Equity	815,304
F-T Liquids Area + refining	369,650	Equity %	24%
Power Block	296,650		
Gas cleanup/polishing	300,197	Debt	2,516,371
Carbon Sequestration Equipment		Debt %	75%
- Compression	-		
- Transportation, Storage, and Monitoring	-		
Balance of Plant	352,601		
Owner's Contingency	110,896		
License Fees & Startup Costs	92,209	Grant	20,000
Design Costs	190,891	Grant %	1%
Subtotal - Facility Costs	2,611,915		
		Debt Composition	
Financing Costs			
		Tranche A	2,516,371
Development Costs	54,248		100%
Closing Costs	50,000		
Credit Subsidy Premium	186,211		
Debt Service Reserve Fund	94,656		
Capitalized Interest	354,645		
Subtotal - Financing Costs	739,760		
Gross Funding Requirements	**$ 3,351,675**	**Total Funds Drawn**	**$ 3,351,675**

Budgetary Impact: The budgetary impact of the Combination Cases is the sum of the individual impacts of the three incentives. The loan guarantee is structured so that the project sponsor funds the credit subsidy premium, resulting in no effect to the Federal budget. For Combination Case 1, the budget impact of the excise tax is $751 million over the 5-year term, and for Combination Case 2, the budget impact of the excise tax is $383 million of the 5-year term. The state grant does not have an impact on the Federal budget. Therefore, the combination of incentives in Combination Case 1 will result in a total Federal budgetary impact of about $751 million, while the combination of incentives in Combination Case 2 will result in a total Federal budgetary impact of about $383 million.

"Power of the Tool" Analysis: The Combination Cases utilize three incentives together to reduce product pricing to the point that the plant's products reach the floor price of crude oil. These cases do this by addressing a wider range of risks and addressing them more effectively than any single incentive can alone. The combination of incentives includes a loan guarantee (Option B), an excise tax credit, and a small development grant. The total impact of the Combination Cases can be attributed to the individual impacts of the three incentives as follows:

- **Loan Guarantee:** The loan guarantee provides the borrower with more affordable financing in the form of decreased interest rates, decreased weighted average cost of capital, increased leverage, and an increased debt amortization period of 26 years. The decreased debt service payments improve cash flow to the project. The loan guarantee and excise tax credit combine to reduce product pricing and assure off-take from the plant.
- **Excise Tax Credit:** The excise tax credit provides the project sponsor with additional income during the ramp-up period of the co-production plant. It improves cash flow in the early years of production, when the presence of improved cash flow has the greatest impact on IRR. Moreover, this incentive promotes operation of the facility, not merely investment in it, because excise tax credits are available only if the project produces FT fuel.
- **Development Grant:** This grant provides the project sponsor with funding prior to loan approval, improving the project's viability from the standpoint of liquidity. Since the project development stage is the most risky time in a project's life cycle, the state development grant facilitates the project development process, increasing the likelihood of project completion.

Summary: With the benefit of three incentives that are currently available and in use today, a co-production plant produces fuel at a price that is competitive to a reasonable floor price for crude oil. In other words, the price for FT fuel in the presence of these three incentives reaches a level on par with the low end of long-term price expectations for crude oil estimated by industry experts ($40 per barrel). Therefore, it is reasonable to assume that early commercial co-production plants supported by the incentive package for Combination Case 2 will be built and will be able to offer competitively priced fuel.

Moreover, by combining three incentives and limiting the excise tax credit to a certain amount per plant, the government can encourage more plants to be built with the same resources. While this Combination Case may seem expensive, paying $383 million out of a total plant cost of $3,350 million for a first of a kind facility can be considered a very effective way for the government to create incentives for an early commercial co-production project. By providing this level of support using these three incentives, for instance, government could facilitate the construction of three or four first-of-a-kind facilities at the same cost of facilitating one plant with a $1,300 million grant. Exhibit 6.15 summarizes the results of the Combination Cases.

Exhibit 6.15: Summary of Combination Case Results

Type of Incentive	FT Diesel Price Per Barrel	Crude-Equivalent Price per Barrel	% Change from Reference Case	Budget Impact ($ millions)	Total Cost ($ millions)
Combination Case 1	$ 43	$ 33	41%	$ 781	$ 781
Combination Case 2	$ 51	$ 39	30%	$ 383	$ 383

F. Concluding Comments

The analysis shows that FT fuels produced from plants backed by incentives can be competitive both at today's market prices and at somewhat lower pricing levels. It should be noted, of course, that the mix and level of incentives provided will vary depending on site-specific factors associated with a project, whether the project is a first-of-a-kind facility or a later early commercial plant, and the strength of supporting private risk mitigation instruments. It should also be noted that the mix of incentives used for the first early commercial co-production plants could depend on availability of incentives of a particular type and the budgetary impact of the incentives utilized. Incentives directed at carbon dioxide sequestration are discussed in Chapter 7.

Interviews confirm that Federal and state agency purchase agreements (good examples of purchase agreements with high quality off-takers) likely will provide a critical underpinning to plant financings for most early commercial co-production projects because they effectively reduce market risk (in this case, price volatility for fuel and power produced in a plant). The analysis shows, in addition, that a combination of several government incentives can cost-effectively create a meaningful "pull" for capital investment (capital grants, investment tax credits, loan guarantees, and accelerated depreciation), production (excise tax credits), and financing (loan guarantees, tax exempt debt). States can use a similar range of incentives, although most frequently at a scale that supplements Federal incentives.

Because incentives address different risks, it is important to select incentives that are appropriate for the risks that a particular project faces. Purchase agreements and incentives are complementary; PAs can be particularly effective in vitiating price volatility in energy markets, high capital cost, and technical uncertainty because they assure revenues. Moreover, the coordination of government incentives (Federal and state) with one another and with private risk mitigation techniques (e.g., warrantees, insurance, purchase agreements) is important to maximizing the chances for successful projects.

IV. SUMMARY AND CONCLUSIONS

This chapter provides the results of an analysis of the impact of potential government incentives on the economics and financial feasibility of a Reference Plant and comments on the applicability of incentives to the management of particular project risks. The analysis shows that a sustained national policy commitment with a tolerance for short term disappointments is likely to be needed to address the level of financial exposure associated with projects of this size, cost, and complexity.

The volatility of oil and gas prices is a major impediment to the construction and operation of early — and, possibly, later — commercial co-production plants, along with uncertainties associated with first-of-a-kind capital-intensive projects. As discussed in Chapter 4, in interviews with a number of investment firms, Scully Capital determined that, in today's energy markets, the threshold valuation of crude oil during the consideration of new capital expenditures has increased, but it still remains well below the current market price for crude oil. Price volatility in crude oil (and natural gas) markets heightens market risk for co-production projects to the point that Scully Capital concludes that a purchase agreement is a necessary element in the financing structure for the first U.S. plants. The analysis reveals two methods to manage price volatility. Purchase agreements assure sale of a plant's production, regardless of fluctuations in market prices, at a price that is sufficient to assure debt repayment. In addition, a combination of incentives may be able to reduce the price needed for FT fuel produced by a project to levels approximating the long-term price assumption for oil, which should largely address lenders concerns over future commodity price risk exposure.

The effect of government incentives analyzed ranges from promoting capital investment (e.g., by decreasing the financing cost of a plant, by facilitating financing) to promoting production. Several incentives can further significantly reduce market and other risks by decreasing the price of FT fuel within the constraint of a target IRR (19 percent in the analysis), although at very different costs to the Treasury; these incentives include loan guarantees, excise tax credits, investment tax credits (ITCs), and cost-sharing. Other incentives have a smaller impact on the price of FT fuel and co-products. In addition to examining the benefits of incentives to project sponsors, Scully Capital examined the potential cost of these incentives to Federal and state governments, concluding that the budgetary impact of an incentive plays an important role in determining whether the incentive is cost-effective, particularly in relation to its policy objective. Exhibit 6.16 presents a summary of the Federal incentives analyzed in Task V.A. and discussed in this chapter.

Exhibit 6.16: Summary of Federal Incentives Analyzed

Type of Incentive	FT Diesel Price per Barrel	Crude-Equivalent Price per Barrel	Percentage Change from Reference Case	Budget Impact ($ millions)	Total Cost ($ millions)
Loan Guarantees					
100% of Debt Guaranteed					
Gov't Pays Credit Subsidy	$ 51	$ 39	30%	$ 188	$ 188
Self-Pay Credit Subsidy	60	46	18%	-	-
80% of Debt Guaranteed					
Self-Pay Credit Subsidy	$ 63	$ 48	14%	$ -	$ -
Tax Incentives					
Investment Tax Credit					
20%	$ 67	$ 52	8%	$ 129	$ 109
20% + Expensing	62	48	15%	194	87
Excise Tax Credit					
5 Years Production					
10 cent	70	54	4%	150	150
25 cent	65	50	11%	375	375
50 cent	57	44	22%	751	751
10 Years of Production					
10 cent	68	52	6%	318	318
25 cent	61	47	16%	795	795
50 cent	54	42	26%	1,591	1,591
50% Expensing of FT Equip.	72	55	1%	20	-
Tax Exempt Debt	$ 71	$ 55	3%	$ 325	$ 643
Other Incentives					
Purchase Agreement (PA)					
OMB A-11 Method	$ 73	$ 56	0%	$ 6,805	$ 6,805
Total Cash Outlay	73	56	0%	10,364	10,364
Grants					
$200 million grant					
Without Repayment	69	53	6%	200	200
With Repayment	68	52	7%	200	200
$1.3 billion grant (50-50 Cost Share)					

A number of significant observations rise from the incentives analysis:

Purchase agreements are a necessary incentive for managing price volatility in crude oil and natural gas markets, but a PA alone may not be sufficient to ensure construction and operation of a co-production plant

Based on the history of energy markets over the past 30 or more years, future energy prices are highly likely to fall below the investment threshold for sufficiently long periods to threaten debt repayment. The financial community has indicated that, because price volatility in crude oil and natural gas markets jeopardizes repayment of project debt, a PA for a substantial portion of a plant's production with a creditworthy off-taker is a threshold for financing a Reference Plant. In general, a PA makes certain the cash flows needed to satisfy debt servicing requirements. Thus, construction and operation of co-production plants would be unlikely in the absence of a PA with creditworthy off-taker, even with the application of other incentives that would otherwise be effective. The more favorable a purchase agreement is to the project sponsor, the more favorable the terms of debt financing.

Purchase agreements have a large budgetary impact

Under methodologies used by the Office of Management and Budget (OMB) and the Congressional Budget Office (CBO), the budgetary impact of a long-term Federal purchase agreement can be larger in the year a PA becomes effective than the total cost of a co-production plant. Budget authority for multi-year agreements must be obligated in the year committed rather than the year spent. If, in the future, the government adopts other methods that involve differential pricing, the budgetary impact of a purchase agreement may be lower. PAs by companies and non-Federal government agencies may not be subject to this limitation. However, to be effective, a PA must be with a creditworthy off-taker.

Loan guarantees can improve the prospect of obtaining financing for a project

Loan guarantees help to decrease the overall project risk that equity and debt investors face and help partially to offset technology, construction, and market risks associated with a project. The ability to finance a project through a non-recourse borrowing backed by a Federal loan guarantee is a powerful inducement for developers and equity providers to develop and invest in projects. A loan guarantee can increase the prospects of obtaining financing, increase leverage, and reduce the interest rate paid.

For projects constructed using a project finance structure, loan guarantees show greater benefit than tax incentives and have a lower budgetary impact

The analysis shows that loan guarantees can provide significant improvements in fuel pricing at a low budgetary cost to projects that utilize project finance structuring. Loan guarantees decrease the price of FT diesel more efficiently (i.e., at a lower budgetary impact) than tax incentives. For example, the budgetary impact of a loan guarantee covering 100 percent of a project's debt for which the government funds the loan guarantee credit subsidy is $188 million; this loan guarantee reduces the price of FT fuels to $51 per barrel, a crude-equivalent price of $39 per barrel. The most beneficial tax incentive — a 50 cent per gallon excise tax credit for 10 years — reduces the FT fuel price to $54 per barrel at a budgetary impact of $1,591 million.

The effectiveness of a loan guarantee depends on its structure

The structure of a loan guarantee has a material impact on the benefit of the incentive. In particular, several factors play an important role in determining the financial effect of a loan guarantee: whether the loan guarantee covers the entire debt or a portion of the debt, what risks the loan guarantee addresses, whether the guaranteed portion of the debt is amortized at the same rate as the un-guaranteed portion, and whether the applicant or the government funds the credit subsidy premium for the loan guarantee.

Production-based tax credits reduce the marginal revenue requirement to produce FT fuels competitively, but they are expensive to the government

Production-based tax credits, such as excise tax credits and production tax credits, provide cash flow based on the level of the tax credit and the quantity of FT fuel production. Tax credits help to reduce the effective price of FT fuel in the market. The competitiveness of FT fuels improves very significantly over the range of excise tax credits evaluated; the highest levels of excise tax credits evaluated yield some of the lowest-priced FT fuel. The cost to the government of excise tax credits and production tax credits is very high, however.

To the extent the law permits, the government can tailor the level of a tax credit depending on the support a plant would need given the prevailing price of crude oil. Unless tailoring is permitted, however, all plants that benefit from production-based tax credits benefit equally, regardless of the level of incentive needed to yield adequate investment returns or, alternatively, allow FT fuel to compete in energy markets.

Investment tax credits (ITCs) decrease the effective cost of equipment

The benefit of an ITC depends on the percentage of the plant to which the incentive applies, the level of the ITC, and the ability of a project sponsor to utilize the tax benefit in the year it is generated. Current tax code confines ITCs to the most “innovative” portion of the plant — the gasification subsystem, not the turbines or coal handling module. As a result, the impact of current ITCs on FT fuel price is relatively small. The larger the percentage of the plant that an ITC can be applied against and the higher the level of the ITC, the lower the effective cost of the capital equipment and the larger the reduction in the price of FT fuel.

Benefits of tax incentives depend on the tax loss absorption capacity of sponsors and the timing of benefits

Tax incentives can create a one-time tax benefit or a continued stream of tax credits or tax losses. A project sponsor can realize the benefits associated with a tax incentive if it has sufficient tax liability to absorb the tax credit or tax loss.

The cash flow of a project will depend on the timing of these benefits. Capital-forming tax incentives (e.g., investment tax credits, accelerated depreciation) decrease the cost of investing in capital equipment by providing early cash flow when the project starts operating. The early cash flow to equity helps improve equity returns more than tax incentives that spread the benefit over time. A production-based tax credit, such as an excise tax credit, could potentially enhance equity returns and provide the necessary coverage to maintain debt service.

Relatively small cost-share grants do not help the financial prospects of co-production plants significantly, and interest-free payback of such grants does not materially impact the economics of the incentive

The analysis shows that small cost-share grants do not significantly improve the financial prospects of an early commercial co-production plant. Moreover, if the size of a cost-share grant is small relative to the entire project cost, payback terms do not change the economic benefits of a grant. Notably, depreciation benefits for the grant amount coupled with a longer repayment period without interest payments account for any sizable impacts associated with this incentive. However, small grants early in the development of a project, when risk is greatest, may increase the chance of project completion.

A 50-50 cost-share grant significantly improves the financial prospects of a first-of-a-kind co-production plant, but it is expensive to the government

A 50-50 cost-share grant improves the economics of a coal co-production plant significantly. A cost share of this magnitude enables an early commercial project by lowering capital costs paid by the sponsor, but it carries a large budgetary impact. A \$1.3 billion cost-share grant reduces the FT fuel price to \$46 per barrel without repayment (\$49 with repayment) at a budgetary impact of \$1.3 billion. By enabling construction of the first few plants utilizing co-production technology, cost-share agreements would help mitigate technology and integration risks in subsequent plants, which otherwise might not be built. Absent similar cost-share agreements for subsequent plants, however, higher capital costs associated with the technology could make obtaining financing for subsequent plants difficult, leaving a continuing need for incentives for co-production plants.

States' ability to assure returns via action by a public utility commission is a very powerful incentive

The authority of public utility commissions to include all or part of the investment in a co-production project in the rate base is potentially an important government incentive for managing market and other risks associated with early commercial co-production projects, particularly those that produce electricity (for export) and pipeline-quality natural gas. In exchange, businesses, local governments, and households would benefit from stable pricing of plant products over the life of the rate-base agreement.

Rate-basing is not subject to the same accounting constraints as government long-term purchase agreements, and rate-basing can be used to complement other incentives to both spread the risks of co-production plants and limit government costs in providing incentives to co-production plants. Rate-basing permits states to benefit in several ways from the construction and operation of co-production projects, including stable pricing of FT fuels for state and local government fleet vehicles, stable pricing of other co-production outputs (e.g., substitute natural gas, electricity) for in-state industries and households, job growth, economic development, use of the state's natural resources, and air pollution reductions.

State incentives also can help promote investment by improving the business climate and speeding development of a project

State incentives can be targeted to provide benefits in numerous ways. For example, development grants assist in developing the project and provide funding assistance before the project reaches financial close. Employment-related tax incentives decrease the cost of employing state residents. Long-term, states can provide an assist to co-production plants by funding research, development, and demonstration of technology advances, by making necessary infrastructure available to enable co-production products to be sold, or by facilitating and accelerating permits for a project.

Combining incentives offers the potential to reduce the risk to a project's long-term competitiveness

If an early commercial co-production facility benefits from a combination of incentives (see previous section) authorized today, it could produce fuel at or below the threshold price for crude oil, which is more than 50 percent less than today's prevailing market price. This finding is important because current rating agency expectations for long-term crude pricing, which are widely recognized as conservative, are in a range of $40 per barrel[27] with an upward bias. Therefore, the use of a combination of incentives largely addresses two key concerns identified in the risk rating process:

- Capital cost risk; and
- Revenue (or market) risk.

These risks would be reduced due to the competitiveness of the FT fuel produced by a facility that benefits from this combination of incentives.

In summary, the incentives analyzed provide a broad range of options that policymakers can utilize to improve the prospects for early commercial co-production plants, particularly through a process that matches incentives to risks. In general,

[27] Watt, Andrew. Lundberg, David. Morrison, Jeffrey. "Industry Report Card: Diverging Natural Gas and Crude Oil Prices Result in a Mixed U.S. Oil and Gas Outlook." Standard and Poor's. September 11, 2007.

incentives that decrease the financing cost of the plant, decrease the effective capital cost of a plant, and encourage production provide the most benefit in enabling the construction and operation of a co-production plant and in reducing the price of its products. Moreover, a ”strong” purchase agreement with a creditworthy off-taker is essential to the project obtaining debt financing and in obtaining financing at a reasonable price. In addition, the budgetary cost to the government compared to the financial “lift” to a specific project (i.e., the “power of the tool”) varies significantly depending on the incentive being considered.

CHAPTER 7: FINANCIAL IMPACTS OF SEQUESTERING CARBON DIOXIDE AND ANALYSIS OF INCENTIVES FOR SEQUESTRATION

I. INTRODUCTION

A. Objectives and Approach

Preliminary lifecycle analyses (or "well-to-wheels" studies) suggest that, unless the carbon dioxide from co-production plants is permanently sequestered (whether in conjunction with EOR operations or otherwise), producing and consuming one gallon of FT transportation fuels could emit up to twice as much carbon dioxide as conventional crude-derived diesel or aviation fuel.[1] However, because the capture of carbon dioxide is an inherent, non-incremental step that enhances production efficiency in the plants that co-produce FT fuels and electricity, these plants may provide an early opportunity for large-scale, cost-effective commercial geological sequestration. With the capture and sequestration of carbon dioxide produced in the gasifiers and FT process, however, FT fuels may be slightly less carbon-intensive than petroleum-based fuels.[2]

Sections II and III of this chapter discuss the prospects for building and operating Reference Plants and Alternative Plants that reduce lifecycle carbon emissions. Section IV summarizes the results of sensitivity testing on these plants, and Section V provides analytic results about the type and level of incentives needed to offset the cost of sequestration. Section VI summarizes the findings and draws inferences from the analysis with a particular focus on results and conclusions that may be useful in managing key risks and identifying barriers for early commercial co-production facilities.

One method of mitigating carbon emissions from a large plant is sequestering them in an underground geologic formation. Sequestration involves separating, compressing, and transporting the carbon dioxide produced in plant operations to an appropriate geologic formation where it can be injected and stored permanently underground. Appropriate geologic formations include deep saline reservoirs, depleted or producing oil and gas fields, and unminable coal seams. These underground formations would be characterized and selected based on their ability to retain carbon dioxide for long periods of time, and during and subsequent to injection operations, monitored to validate their performance. Compressed carbon dioxide streams can be used for enhancing hydrocarbon recovery from depleted oil reserves. This process of enhanced oil recovery, or EOR, can be conducted in conjunction with permanent storage. For

[1] "Greenhouse Gas Impacts of Expanded Renewable and Alternative Fuels Use" Environmental Protection Agency, Office of Transportation and Air Quality. EPA420-F-07-035. April 2007. Clayton, Mark. "Coal in cars: great fuel or climate foe" Christian Science Monitor. March 2, 2007.

[2] Unpublished paper. Department of Energy. National Energy Technology Laboratory (NETL). August 2007. The results may vary by a few percent in either direction depending on the type of production process used in the plant, the plant's source of electricity, and the type of oil used in the comparison.

purposes of this report, EOR operators are assumed to sequester carbon dioxide permanently.

Capturing the carbon dioxide is typically the largest cost component in the capture and sequestration process in coal-based facilities.[3] In two major processes within co-production plants, coal gasification and in the production of FT fuels, however, the capture of carbon dioxide is an inherent, non-incremental step that overall plant performance. Thus, the marginal cost of sequestering the carbon dioxide in gasification-based co-production projects, including those that produce FT fuels, is the cost to compress, transport, and store it. As a result, a coal co-production plant that produces FT fuel may provide one of the early opportunities for large-scale, cost-effective commercial geological sequestration. It should be emphasized that commercial sequestration on a large scale will involve overcoming a number of technological, integration, regulatory, legal, and financial hurdles; most of these issues are outside the scope of this analysis and are discussed elsewhere in depth. Also, the capacity for geological sequestration is limited, so other anthropogenic sources of carbon dioxide will compete to utilize this capacity.

Section II of this chapter builds up step-by-step the cost to sequester the carbon dioxide and provides the results of an analysis of these costs. For each coal type, a Reference Plant that captures the carbon dioxide, but does not compress, transport, store, or monitor[4] the captured carbon dioxide, is considered. Then, the cost to compress the carbon dioxide is considered. Finally, this chapter reports the results of the Task V.B. examination of the marginal costs of sequestering carbon dioxide in geologic formations (i.e., the cost to transport, store, and monitor the carbon dioxide). This chapter also analyzes the impact of sequestering the carbon dioxide produce in plant operations on the economic and financing prospects for Reference Plants — which utilize bituminous coal or lignite — and Alternative Plants (based on work performed in Task III) — which utilize bituminous coal, sub-bituminous coal, or lignite. (For purposes of this analysis of sequestration, Scully Capital developed a third Reference Plant that utilizes sub-bituminous coal.)

Building on analyses of the impact of incentives on Reference Plant financial results provided in Chapter 6, Alternative Plants provided in Chapter 4, and potential incentives for sequestering carbon dioxide conducted in Task V.B., this chapter examines what types and level of incentives may be required to mitigate the financial impacts of increased costs associated with carbon sequestration. In particular, the results highlight certain targeted tax incentives for carbon dioxide sequestration. The analysis shows that incentives of this type are more useful than other incentives (such as loan guarantees and investment tax credits) because they can be structured to align with the marginal cost of sequestration. Investment tax credits cannot be targeted at the

[3] Intergovernmental Panel on Climate Change (IPCC) Working Group III. "IPCC Special Report on Carbon Dioxide Capture and Storage – Summary for Policymakers" Page 10. September 2005.

[4] The terms "monitor" and "monitoring" should be read throughout as meaning "measurement, monitoring, and verification."

operation of sequestration equipment, and while loan guarantees can be used to offset the price of sequestration, they cannot be targeted specifically at sequestration.

This chapter provides an analysis of the differing effects of this targeted tax incentive on the economics and financeability of co-production plants that sequester the carbon dioxide they produce in underground geologic formations, including in some cases using it for EOR. In doing so, the results enhance our understanding of potential government incentives on carbon sequestration for industrial gasification projects and the relationship of these incentives to the overall financial prospects of industrial gasification projects.

This report does *not* attempt to analyze the economic forces that would face co-production facilities in the context of a mandatory greenhouse gas (GHG) emissions reductions scheme. Plant operators facing mandatory carbon emissions limits would respond to additional price signals — namely, the price associated with emitting GHGs into the atmosphere — which would materially affect financial analyses such as those conducted as part of this study. This study assumes that emissions of carbon dioxide are not limited by statute or regulation.

The results reported in Chapter 3 suggest that, without the use of incentives, the crude-equivalent price of FT fuels from a mid-size bituminous co-production plant would need to be in the range of $55–$60 per barrel.[5] Advocates for the commercial deployment of coal gasification with co-production suggest that government incentives could facilitate project financing through improved economics or risk assumption. The results reported in Chapter 6 confirm this suggestion.

The Reference Plant and Alternative Plant analyses utilize a non-recourse project financing structure. Under this type of financing structure, a project “stands on its own” and its cash flows provide the underpinnings of creditworthiness. Conversations with developers and financiers indicated that this type of structure would likely be utilized for most early commercial plants. Importantly, this structure insulates project sponsors from the full risk of the project, allowing risks to be shared by several participants in the project. To accomplish the objectives of this chapter, Scully Capital conducted five sub-tasks (see list in Chapter 1).

B. Chapter Organization

This rest of this chapter is organized into five sections. Appendix B provides carbon balance schematics for the three Reference Plants. The five sections are:

[5] In a scenario in which the after tax internal rate of return (IRR) is 15 percent and other financial assumptions remain the same, the crude-equivalent price of FT fuels would need to be in the range of $47 per barrel.

- **Cost of Sequestration for Reference Plants, Its Effect on Output FT Fuel Price, and the Effect of Enhanced Oil Recovery (EOR):** This section describes the cost components of sequestration and develops economics for the three Reference Plants. It also analyzes the economics of using the carbon dioxide in EOR operations.
- **Cost of Sequestration for Alternative Plants, Its Effect on Output FT Fuel Price, and the Effect of EOR:** This section provides the technical and cost assumptions associated with sequestration of the carbon dioxide produced in Alternative Plants and analyzes the effect on FT fuel price of incorporating these assumptions into the Alternative Plant. It also provides the results of analyses similar to those conducted for the Reference Plants regarding the impact of increased electricity prices and of the minimum FT fuel price required to meet debt service requirements.
- **Sensitivity Analysis for Alternative Plant with Sequestration:** This section presents the results of applying relevant sensitivity testing to a bituminous coal-based Alternative Plant that sequesters carbon dioxide produced in plant operations. To facilitate comparison with the sensitivity analyses of the Reference Plant and the Alternative Plant, Scully Capital analyzed many of the same sensitivities. This section compares and evaluates the impact of fluctuations in key inputs to the Alternative Plant and the Alternative Plant with sequestration, including a plant with sequestration to EOR.
- **Impact of Incentives for Sequestration:** This section provides the results of the analysis of the type and level of incentives needed to offset the cost of sequestration for Reference Plants and Alternative Plants. The analysis then utilizes a standard level of incentive to determine its economic effect on EOR operations for each plant. The section also comments on the applicability of particular incentives to key risks, as identified by principals and other experts. Finally, the section provides the results of a sensitivity analysis of fluctuations in key inputs associated with sequestration and the level of a tax credit-based incentive for sequestration.
- **Summary and Conclusions:** This section summarizes the findings and draws inferences from the analysis with a particular focus on results and conclusions that may be useful in managing key risks and identifying barriers for early commercial co-production facilities that use various types of coal, produce varying proportions of key outputs, and sequester the carbon dioxide produced in plant operations.

II. COST OF SEQUESTRATION FOR REFERENCE PLANTS, ITS EFFECT ON OUTPUT FT FUEL PRICE, AND THE EFFECT OF ENHANCED OIL RECOVERY (EOR)

This section presents the technical and financial assumptions for the analysis of three mid-sized (approximately 30,000 bpd) Reference Plants that utilize bituminous and sub-bituminous coal and lignite. The cost to sequester the carbon dioxide is built up step-by-step. For each coal type, a Reference Plant that captures the carbon dioxide, but does not compress, transport, store, or monitor the captured carbon dioxide, is considered first. This analysis is analogous to the development of cost estimates for Reference Plants presented in Chapter 3. Then, the cost to compress the carbon dioxide is considered. Finally, the cost to transport, store, and monitor the carbon dioxide is considered. In all cases, as in previous chapters, a non-recourse project financing structure is applied to the technical assumptions in financial modeling.

Scully Capital based its analysis on a “greenfield” plant that could be viewed as indicative of co-production plants that would be considered for early commercial facilities. As in previous tasks, the technical assumptions used in this study were derived from the American Energy Security Study (AES Study) sponsored by Southern States Energy Board (“SSEB”).[6] The AES Study relied on cost estimates developed in late 2005 and used in a technical analysis conducted by Mitretek; importantly, these estimates are preliminary in nature and could vary by +/- 30 percent.[7]

This section is divided into following subsections:

- Technical Information on Reference Plants;
- Costs of Sequestration for Reference Plants;
- Price of FT Fuel from Reference Plants with the Addition of Carbon Compression, Transportation, and Sequestration; and
- Summary

A. Technical Information on Reference Plants

Exhibit 7.1 provides the technical basis for the three Reference Plants. It provides the output parameters of each of the Reference Plants including the decrease in net electricity output resulting from parasitic loads associated with carbon compression.

[6] “American Energy Security – Building a Bridge to Energy Independence and to a Sustainable Energy Future” The Southern States Energy Board. July 2006. “AES Study”
[7] ibid. Appendix D. Page 16.

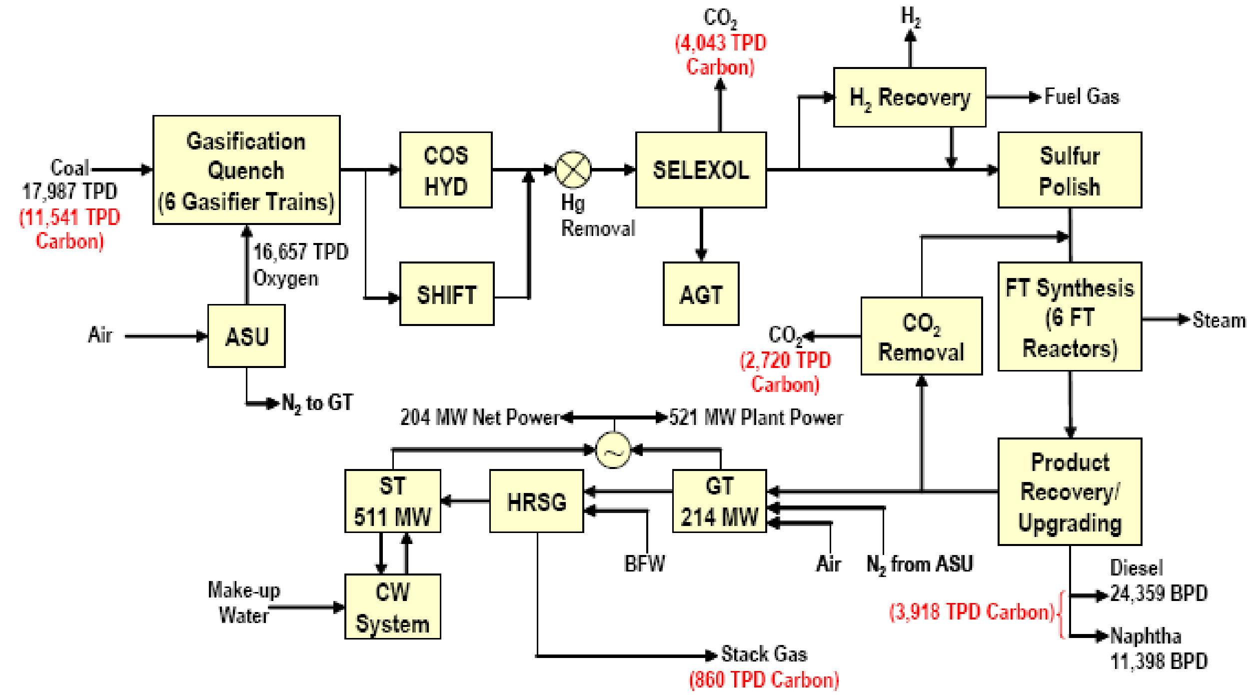
Exhibit 7.1: Technical Information for Reference Plants, With CC and With CC&C

Type of Coal Co-Production Plant	Bituminous Reference Plant	Sub-bituminous Reference Plant	Lignite Reference Plant
Input Characteristics			
Tons of Coal Per Day	17,987	22,988	33,697
BTU Value of Bituminous Coal	11,800	8,500	6,500
Price of Coal Delivered	$36 / Short Ton	$11 / Short Ton	$10 / Short Ton
Output Characteristics @ Capacity			
FT Liquids (bpd)			
FT Diesel	24,359	23,984	24,284
Naptha	11,398	11,222	11,362
Total: FT Diesel Equivalent	32,502	32,001	32,401
Electricity Production			
Gross (MWe)	725	597	617
Parasitic Load	468	398	473
Net (MWe)	257	199	144
Net (MWe) with CC&C	205	146	91
Plant Characteristics			
Efficiency (HHV) with CC&C	48%	50%	46%
Gasifier Trains	6	6	8
Spare Gasifier	No	No	No
FT Reactors	6	6	6
Other Characteristics			
Construction Time	3 Years	3 Years	3 Years
Availability			
1st Year	51%	51%	51%
2nd Year	81%	81%	81%
3rd+ Year	90%	90%	90%

The three Reference Plants have similar FT outputs: Each plant produces approximately 24,000 barrels of FT diesel per day and 11,400 barrels of naphtha per day, or approximately 32,000 barrels of FT diesel-equivalent fuel per day. Of the three Reference Plants, the one that uses sub-bituminous coal is the most efficient. The gasifier designs used for the three coals are different. While the plant using bituminous coal has a slurry-fed gasifier, the sub-bituminous coal and lignite plants have a dry-fed gasifier design that is inherently more efficient. The Reference Plant that uses lignite has two extra gasifiers for processing larger quantities of coal. Construction and operation of the three Reference Plants are similar.

Exhibit 7.2 presents a schematic for a Reference Plant that uses bituminous coal. The schematic illustrates the amount of carbon dioxide produced and, potentially, captured based on a conservative set of assumptions.

Exhibit 7.2: Schematic and Carbon Balance for Bituminous Coal Reference Plant



CO_2 Captured	Tons C	Tons CO_2
From Selexol	4,043	14,824
Post-FT	2,720	9,973
Total	6,763	24,798
Total @ 90% Utilization	6,087	22,318
Total @ 80% Capture	4,869	17,854

This Reference Plant uses 17,987 tons of coal per day, of which the carbon content is 11,541 tons. Exhibit 7.2 provides the carbon balance for the plant. Of the 11,541 tons of carbon in the coal, 3,918 tons of carbon is present in the FT diesel and naphtha. Carbon capture occurs in two places: the Selexol unit and the post-FT process (before syngas recycling). Combined, these two units extract 6,763 tons of carbon, or 59 percent of the carbon in the coal. The power generation stack gas contains the remaining 860 tons of carbon.

The Selexol unit and post-FT processing separate carbon dioxide from other streams, allowing the captured carbon to be compressed and transported. Current technology limits capture to approximately 90–95 percent of total carbon (excluding the carbon in FT fuels produced in the plant). Mitretek assumed this 90–95 percent capture rate in the Selexol and post-FT carbon dioxide removal units. To be conservative, however, this analysis assumes an overall 75 percent capture rate, though other studies have used different capture rates. Once the plant reaches steady state, it is expected to operate at an average availability of 90 percent. Hence, using the conservative assumptions outlined above, the Reference Plant captures 4,869 (or 6,763 * 90% * 80%) tons of carbon per day. The volume of carbon dioxide that can be captured is derived by multiplying this number by the ratio of the molecular weight of carbon dioxide (44) and the molecular weight of carbon (12) gives: 4,869 * 44 / 12 tons per day = 17,854. A similar analysis shows that 16,476 and 18,889 tons of carbon dioxide per day can be captured from the sub-bituminous coal and lignite Reference Plants, respectively. Exhibit 7.3 provides a summary of the Mitretek carbon balance analysis of all three Reference Plants, as well as the more conservative assumptions used in this analysis (see Appendix B for the schematic diagrams of all three Reference Plants).

Exhibit 7.3: Carbon Dioxide Captured in Three Co-Production Reference Plants

Type of Coal Co-Production Plant	Bituminous Coal Reference Plant	Sub-bituminous Coal Reference Plant	Lignite Reference Plant
Carbon Captured (TPD)			
From Selexol	4,043	3,516	4,383
From Post-FT	2,720	2,725	2,772
Total	6,763	6,241	7,155
Carbon Capture Calculation (TPD)			
at 90% Availability	6,087	5,617	6,440
at 80% Capture	4,869	4,494	5,152
CO_2 Captured (TPD)	17,854	16,476	18,889

B. Costs of Sequestration for Reference Plants

The AES Study provided the capital and operating costs to capture and compress carbon dioxide produced in the Reference Plants, and Scully Capital utilized a variety of published sources to research the cost to transport, store, and monitor the carbon dioxide. Published sources provide the capital cost of transporting carbon dioxide, while capital costs are not available for storing and monitoring carbon dioxide. The cost of storing and monitoring carbon dioxide is calculated on a per ton basis.

The limited number of commercial carbon storage facilities substantially increases uncertainty associated with cost estimates for injection, long-term storage, and monitoring. It is expected that, as carbon capture and storage systems are deployed in the field, cost figures will be clarified, though site-specific variations will still exist. The costs associated with carbon capture and storage (CCS) are treated as follows:

- **Carbon Dioxide Capture (CC):** Co-production plants that produce FT fuel capture the carbon dioxide to optimize plant cost and performance. Because the plants separate the carbon dioxide from the syngas and during upgrading of FT fuels they produce, the cost of CC is not included in the cost to sequester carbon dioxide.

- **Compression:** The cost to compress the captured carbon dioxide consists of the capital cost of the compressors and increased operating costs associated with the plant's parasitic load. The AES Study estimates the capital cost of compression to be \$50–\$58 million, depending on the Reference Plant. The increase in parasitic load for all three plants is estimated to be about 53 MWe.

- **Transportation:** A Global Energy Technology Strategy Program (GTSP) study showed that 95 percent of the 500 largest point sources of carbon dioxide are within 50 miles (80 km) of a suitable carbon dioxide storage reservoir.[8] This analysis thus uses the capital and operating costs for a 50-mile pipeline, reflecting the assumption that a pipeline of 50 miles or less will likely be built to either a saline aquifer or an EOR operation.

  The formula for the capital cost of the pipeline in 2005 dollars is given by:[9]

  $$C_{total} = F_L * F_T * L * 9970 * (m^{0.35}) *(L^{0.13}), \text{ where}$$

  F_L = 1 for USA
  F_T = 1.1 for jungle / stony desert[10]
  m = Carbon dioxide mass flow rate in the pipeline (tonnes / day) is rounded up to 30,000 tonnes / day
  L = pipeline length in kilometers = 80 km

  Thus, the capital cost of the pipeline is $1 * 1.1 * 80 * 9970 * (30{,}000^{0.35}) * (80^{0.13})$, or \$57.2 million. According to the Bureau of Labor Statistics, the price of steel increased 9 percent from 2005 to 2006.[11] As a result, the overnight capital cost of the pipeline used in the study is \$62.5 million, which translates into \$1.25 million per mile. The same GTSP study estimates that the annual operation and maintenance for the pipeline is 2.5 percent of capital cost, or \$1.56 million.

  An important operating cost that is not included in the GTSP study is the liability cost of the pipeline. The liability issues surrounding a carbon dioxide pipeline are a subject of considerable debate. Some states, such as Texas, have decided to indemnify pipeline operators for pipeline risk. Other states, such as Illinois, are opting to build carbon dioxide pipelines and collect use-based payments from private entities. Given the uncertainty of this issue, liability costs have not been included in the analysis.

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[8] Dooley. J, et.al. "Carbon Dioxide Capture and Geologic Storage: A Core Element of a Global Energy Technology Strategy to Address Climate Change" Global Energy Technology Strategy Program (GSTP). Page 29. April 2006.

[9] McCollum, D. Ogden, J. "Techno-Economic Models for Carbon Dioxide Compression, Transport, and Storage" Page 10. Institute of Transportation Studies. University of California, Davis. October 2006.

[10] This is mid-point value of the options given in the study.

[11] Bureau of Labor Statistics. The Producer Price Index for steel mill products increased from an average of 159.7 in 2005 to an average of 174.3 in 2006. February 2007.

- **Storage:** Storage costs can vary significantly depending upon site-specific considerations, including the geologic characteristics of the target formations (e.g., depth, thickness, permeability, storage capacity). Net cost will vary depending on whether the carbon dioxide is stored long-term in a saline aquifer, sequestered in an EOR application, or used in EOR without sequestration. The IPCC Working Group conducted an analysis of past work in this area, arriving at high end cost values of $4.5 per ton of carbon dioxide stored in a saline aquifer and $4.0 per ton of carbon dioxide in a depleted oil reservoir (in 2003 dollars).[12] Assuming 2 percent inflation, the cost in 2006 would be $4.78 per ton to store carbon dioxide in saline aquifers and $4.24 per ton to use and sequester carbon dioxide in EOR applications. Because these costs are of the same order of magnitude, Scully Capital used $4.78 per ton of carbon dioxide as the cost to store the carbon dioxide in both saline aquifers and EOR operations. It should be noted that this analysis may not take into account all of the costs associated with the detailed site characterization which is part of preparing a geological sequestration site for operations.

- **Measurement, Monitoring, and Verification (MMV):** Once the carbon dioxide has been injected underground, costs are incurred for monitoring and verification. Monitoring and verification are fundamental components of all geologic sequestration projects for risk management purposes and to confirm that the carbon dioxide is being sequestered without leakage. The IPCC estimated the cost of monitoring and verification activities to be in the range $0.1–$0.3 per ton of carbon dioxide.[13] This study assumes the cost will be the more conservative $0.3 per ton for monitoring the carbon dioxide.

C. Price of FT Fuel from Reference Plants with the Addition of Carbon Compression and Sequestration

Scully Capital built the price of FT fuel from co-production plants with sequestration in a step-by-step manner. First, Scully Capital developed the price of fuel for a Reference Plant without compression equipment (i.e., assuming release of the carbon dioxide into the atmosphere). These cases are termed the “base cases.” Then, capital and operating costs for compressing the carbon dioxide were added. These cases, referred to as the “base cases with carbon capture and compression (CC&C),” provide the price of FT fuel if carbon dioxide is compressed to pipeline quality and handed off at the plant boundary. Finally, Scully Capital calculated the cost to transport and store the compressed carbon dioxide and to monitor and verify its fate. These cases are termed the “base cases with sequestration.” For each of the three Reference Plants (based on type of coal), two sequestration scenarios are presented: the cost to sequester the

[12] Intergovernmental Panel on Climate Change (IPCC) Working Group III. “IPCC Special Report on Carbon Dioxide Capture and Storage” Page 260. September 2005.

[13] ibid. Summary for Policy Makers. Page 11.

carbon dioxide in a saline aquifer and the effect of revenues from EOR with sequestration.

1. Base Cases

As noted earlier, Scully Capital applied a non-recourse project finance structure to engineering cost estimates from the AES Study to arrive at an estimate of total facility cost for the three Reference Plants. Salient points of the structure include a 15-year debt amortization term based on a long-term off-take agreement with a creditworthy counterparty, a debt service reserve fund, and development and financing costs.

Based on these assumptions, Scully Capital determined the price of FT fuel that achieves the target after tax internal rate of return ("IRR") of 19 percent, which is in the range anticipated by private equity markets. The price of FT diesel resulting from this analysis is the crude-equivalent price (CEP) plus the cost of refining the product, not including distribution, marketing, and taxes. An industry proxy widely used in converting a CEP to the price of diesel after refining consists of multiplying the crude oil price by 1.3 to arrive at a diesel-equivalent price. For example, if the FT diesel price were $72.83 per barrel, the equivalent price for crude oil would be $56 per barrel (72.83 / 1.3). While FT fuel contains a *de minimus* quantity of sulfur, this analysis did not monetize the premium for ultra-low sulfur diesel because of uncertainties about the level of the premium over time and to assure conservatism in financial projections. Exhibit 7.4 presents the sources and uses statement, the resultant price of FT fuel, the CEP, and the minimum and average debt service coverage ratio (DSCR) for the three Reference Plants with carbon dioxide capture (i.e., without compression, transportation, storage, and monitoring costs).

Exhibit 7.4 shows that, at $3.09 billion, the Reference Plant that uses sub-bituminous coal has the lowest overall cost. The overall costs for the bituminous coal and lignite Reference Plants are $3.27 billion and $3.61 billion, respectively. The increased cost for the Reference Plant that uses lignite traces to the additional costs to handle larger amounts of coal, particularly costs associated with added gasifiers and solids handling capacity. The net difference between Reference Plants that use sub-bituminous and bituminous coal traces to the higher cost of the air separation unit for the latter.

Exhibit 7.4: Sources and Uses and Key Outputs for Three Reference Plants

(in $000s)	Bituminous Reference Plant	Sub-bituminous Reference Plant	Lignite Reference Plant
USES			
Facility Costs			
Solids Handling	$ 166,616	$ 193,671	$ 268,071
Air Separation Unit	261,673	181,886	193,395
Gasification	470,533	470,533	627,377
F-T Liquids Area + refining	369,650	354,441	362,720
Power Block	296,650	264,964	274,480
Gas cleanup/polishing	300,197	308,435	341,613
Carbon Sequestration Equipment			
- Compression	-	-	-
- Transportation, Storage, and Monitoring	-	-	-
Balance of Plant	352,601	330,216	402,450
Owner's Contingency	110,896	105,207	123,505
License Fees & Startup Costs	92,209	72,176	83,290
Design Costs	190,891	180,977	212,345
	2,611,915	2,462,506	2,889,247
Financing Costs	657,147	623,692	720,551
Gross Funding Requirements	**$ 3,269,062**	**$ 3,086,198**	**$ 3,609,797**
Increase from Reference Case	0%	0%	0%
SOURCES			
Equity: 30%	$ 980,719	$ 925,859	$ 1,082,939
Debt: 70%	2,288,343	2,160,339	2,526,858
OUTPUTS			
Price of FT Fuel (19% IRR)	**$72.83 /bbl**	**$59.00 /bbl**	**$76.00 /bbl**
Crude-Equivalent Price	**$56.02 /bbl**	**$45.38 /bbl**	**$58.46 /bbl**
% Increase from Reference Case	0%	0%	0%
$/bbl Increase from Reference Case	$0.00	$0.00	$0.00
Minimum DSCR	1.67x	1.66x	1.65x
Average DSCR	2.16x	2.16x	2.16x

The lower capital costs and lower coal costs for the sub-bituminous coal-based Reference Plant translates into the lowest cost for FT diesel. The lower capital cost of the bituminous Reference Plant offsets high coal prices to yield the second lowest cost of FT diesel, ahead of the FT diesel cost from the lignite plant. The price of FT fuel from the sub-bituminous Reference Plant is projected to be $59 (CEP: $45) per barrel. For the bituminous coal and lignite Reference Plants, respectively, the projected FT diesel prices are $73 (CEP: $56) and $76 (CEP: $58) per barrel. The sub-bituminous Reference Plant benefits from lower capital cost, lower operating cost (from lower priced sub-bituminous coal), and higher plant efficiency. Each of the FT diesel prices at 19 percent IRR allows for a minimum DSCR of 1.65x and an average DSCR of 2.16x.

2. Base Cases with CC&C

Building upon the base cases, Scully Capital added capital and operating costs for carbon dioxide compression. As noted earlier, capture of carbon dioxide is integral to both the gasification and FT processes and, as a result, the marginal cost for CC&C is the cost to compress the carbon dioxide. Capital costs for CC&C include the cost of compressors, and operating costs include an increase in parasitic load to operate the compressors. The increase in parasitic load is in the range of 50–55 MWe for all three Reference Plants.

Exhibit 7.5 provides the sources and uses for the three Reference Plants with CC&C and the key outputs, including price of FT fuel, that achieve 19 percent IRR. The analysis shows that the overall uses of funds increases by 2 percent in each base case with CC&C, with additional hard costs in the $50–$60 million range for the compressor. Interestingly, the increase needed in the FT fuel price to achieve 19 percent IRR is inversely proportional to the starting price of FT fuel. This result occurs because the increase in price on a per barrel basis is similar ($4/barrel) across the three Reference Plants with CC&C. As a result, the price of FT fuel from a sub-bituminous coal Reference Plant increases by 7 percent to $63 (CEP: $48) per barrel with the addition of CC&C, while FT fuel from the bituminous coal Reference Plant increases to $77 (CEP: $59) per barrel and fuel from the lignite Reference Plant increases to $80 (CEP: $62) per barrel. The minimum DSCR and average DSCR do not change materially from the base cases. Compression thus adds 5–7 percent to the price of FT fuel needed to achieve 19 percent IRR in all three Reference Plants.

Exhibit 7.5: Sources and Uses and Key Outputs for Three Reference Plants with CC&C

(in $000s)	Bituminous Reference Plant with CC&C	Sub-bituminous Reference Plant with CC&C	Lignite Reference Plant with CC&C
USES			
Facility Costs			
Solids Handling & ASU	$ 428,289	$ 375,558	$ 461,467
Gasification and FT	840,183	824,973	990,097
Power Block + Gas Cleaning	596,847	573,399	616,093
Balance of Plant	352,601	330,216	402,450
Carbon Sequestration Equipment	-	-	-
- Compression	54,561	50,370	57,750
- Transportation, Storage, and Monitoring	-	-	-
Owner's Contingency	113,624	107,726	126,393
License Fees & Startup Costs	92,209	72,176	83,290
Design Costs	190,891	180,977	212,345
	2,669,204	2,515,395	2,949,884
Financing Costs	670,323	635,856	734,497
Gross Funding Requirements	**$ 3,339,527**	**$ 3,151,251**	**$ 3,684,381**
Increase from Reference Case	2%	2%	2%
SOURCES			
Equity: 30%	$ 1,001,858	$ 945,375	$ 1,105,314
Debt: 70%	2,337,669	2,205,875	2,579,066
OUTPUTS			
Price of FT Fuel (19% IRR)	**$76.88 /bbl**	**$63.04 /bbl**	**$80.16 /bbl**
Crude-Equivalent Price	**$59.14 /bbl**	**$48.49 /bbl**	**$61.66 /bbl**
% Increase from Reference Case	6%	7%	5%
$/bbl Increase from Reference Case	$4.05	$4.04	$4.16
Minimum DSCR	1.67x	1.66x	1.65x
Average DSCR	2.16x	2.17x	2.17x

3. Base Cases with Sequestration

Building upon the base cases with CC&C, Scully Capital added the costs for carbon dioxide transportation and storage and for monitoring sequestered carbon dioxide. (While the transportation, storage, and monitoring of carbon dioxide in a sequestration operation is likely to be a separate business external to a co-production plant, these costs are added to the plant's capital and operating costs for comparative purposes in this analysis.) The variable costs to store and monitor the captured carbon dioxide are added to plant operating costs, along with the capital and operating costs of the carbon dioxide pipeline and the sequestration operation. Exhibit 7.6 shows the effects of the additional capital and operating costs.

Exhibit 7.6: Sources and Uses and Key Outputs for Three Reference Plants with Sequestration

(in $000s)	Bituminous Reference Plant with Sequestration	Sub-bituminous Reference Plant with Sequestration	Lignite Reference Plant with Sequestration
USES			
Facility Costs			
Solids Handling & ASU	$ 428,289	$ 375,558	$ 461,467
Gasification and FT	840,183	824,973	990,097
Power Block + Gas Cleaning	596,847	573,399	616,093
Balance of Plant	352,601	330,216	402,450
Carbon Sequestration Equipment	-	-	-
- Compression	54,561	50,370	57,750
- Transportation, Storage, and Monitoring	63,836	63,836	63,836
Owner's Contingency	116,816	110,918	129,585
License Fees & Startup Costs	97,720	77,294	89,095
Design Costs	190,891	180,977	212,345
	2,741,742	2,587,541	3,022,717
Financing Costs	686,839	652,293	751,072
Gross Funding Requirements	**$ 3,428,581**	**$ 3,239,834**	**$ 3,773,789**
Increase from Reference Case	5%	5%	5%
SOURCES			
Equity: 30%	$ 1,028,574	$ 971,950	$ 1,132,137
Debt: 70%	2,400,007	2,267,884	2,641,652
OUTPUTS			
Price of FT Fuel (19% IRR)	**$82.83 /bbl**	**$68.73 /bbl**	**$86.35 /bbl**
Crude-Equivalent Price	**$63.72 /bbl**	**$52.87 /bbl**	**$66.42 /bbl**
% Increase from Reference Case	14%	16%	14%
$/bbl Increase from Reference Case	$10.00	$9.73	$10.35
Minimum DSCR	1.67x	1.66x	1.65x
Average DSCR	2.17x	2.17x	2.17x

The price of FT fuel needed to maintain 19 percent IRR increases by 14 to 16 percent in the three base cases to the range $69 (CEP: $53) to $86 (CEP: $66) per barrel. The transportation cost is kept constant across the three cases, but storage and monitoring costs vary with the amount of injected carbon dioxide. Exhibit 7.3 illustrates that a sub-bituminous coal-based Reference Plant will emit the least carbon dioxide, followed by a bituminous coal-based Reference Plant and a lignite-based Reference Plant. As a result, the difference between the sequestration costs for a bituminous coal-based Reference Plant and a lignite-based Reference Plant would be slightly higher than the differential sequestration cost for the sub-bituminous coal-based Reference Plant.

4. Base Cases with Sequestration and EOR

In some circumstances, plant operators may have the opportunity to sell compressed carbon dioxide separated during co-production for use in extracting oil from depleted fields. In examining the impact of EOR, Scully Capital again assumes for comparative purposes that the owner of a co-production plant would also own and operate the carbon dioxide sequestration operation. The project would sell, deliver, and inject the carbon dioxide for injection to recover oil, enabling it to receive benefits from a tax credit analyzed in the next section. (As noted earlier, the study assumes that the carbon dioxide is stored permanently in the depleted fields).

The same transportation, storage, and monitoring costs discussed in the previous section (base case with sequestration), and revenues from recovered oil are excluded from this analysis of the effect of EOR. Scully Capital assumes, based on research conducted for this study, that the owner may be able obtain revenue of $12 per ton of carbon dioxide under a long-term contract for all the carbon dioxide produced in a plant and permanently sequestered. Exhibit 7.7 presents the results of the analysis. It should be noted, however, that industry sources suggest that the price paid for carbon dioxide delivered for EOR purposes may have a fairly wide range: from $5 per ton to $12 per ton.

The analysis shows that, if the plant can sell captured carbon dioxide under a long-term contract for $12 per ton (and increasing with inflation), the revenue from sales of carbon dioxide to the EOR operation would roughly offset the costs of compressing, transporting, sequestering, and monitoring the carbon dioxide. The price of FT fuels from sub-bituminous coal decreases the least because its manufacture produces the smallest amount of carbon dioxide. The price for FT fuels made from bituminous coal, with EOR, is $73.07 versus $72.83 per barrel in the base case. The difference is not material in light of the +/-30 percent error band in the design cost estimate. The price of FT fuel from a lignite-based Reference Plant with sequestration and EOR is the same as in the base case, or $76 per barrel. In all three cases, this scenario assumes, critically, that there is an off-taker for all the carbon dioxide produced by the plant for the life of plant operations (30 years).

Exhibit 7.7: Sources and Uses and Key Outputs for Reference Plants with EOR

(in $000s)	Bituminous Reference Plant with EOR	Sub-bituminous Reference Plant with EOR	Lignite Reference Plant with EOR
USES			
Facility Costs			
Solids Handling & ASU	$ 428,289	$ 375,558	$ 461,467
Gasification and FT	840,183	824,973	990,097
Power Block + Gas Cleaning	596,847	573,399	616,093
Balance of Plant	352,601	330,216	402,450
Carbon Sequestration Equipment	-	-	-
- Compression	54,561	50,370	57,750
- Transportation, Storage, and Monitoring	63,836	63,836	63,836
Owner's Contingency	116,816	110,918	129,585
License Fees & Startup Costs	97,720	77,294	89,095
Design Costs	190,891	180,977	212,345
	2,741,742	2,587,541	3,022,717
Financing Costs	686,839	652,293	751,072
Gross Funding Requirements	**$ 3,428,581**	**$ 3,239,834**	**$ 3,773,789**
Increase from Reference Case	5%	5%	5%
SOURCES			
Equity: 30%	$ 1,028,574	$ 971,950	$ 1,132,137
Debt: 70%	2,400,007	2,267,884	2,641,652
OUTPUTS			
Price of FT Fuel (19% IRR)	**$73.07 /bbl**	**$59.58 /bbl**	**$76.00 /bbl**
Crude-Equivalent Price	**$56.21 /bbl**	**$45.83 /bbl**	**$58.46 /bbl**
% Increase from Reference Case	0%	1%	0%
$/bbl Increase from Reference Case	$0.24	$0.58	$0.00
Minimum DSCR	1.67x	1.66x	1.65x
Average DSCR	2.17x	2.17x	2.17x

D. Summary

Co-production plants that produce FT fuel may offer an early opportunity for commercial carbon dioxide sequestration operations because the cost of carbon capture is embedded in the capital and operating costs of standard plants. For most other large coal-based facilities, capturing the carbon dioxide will be the largest portion of the cost of sequestration. In co-production facilities that produce FT fuels, however, capturing carbon dioxide is integral to plant operations (i.e., for efficient production of the syngas and FT fuels). As a result, the marginal cost of sequestration in co-production plants derives from the cost of compressing, transporting, storing, and monitoring the carbon dioxide.

Exhibit 7.8 provides the price of FT fuel needed to achieve 19 percent IRR for three different coal types and plant configurations. For all three, the base case price of FT fuel assumes the release of all of the captured carbon dioxide into the atmosphere. In "with CC&C" scenarios, captured carbon dioxide is compressed for hand-off to a carbon dioxide pipeline at "plant-gate." In scenarios "with sequestration," compressed carbon dioxide is transported, stored, and monitored at a suitable reservoir. Finally, the "with EOR" scenarios assume the use of the carbon dioxide for EOR with permanent sequestration and revenues of $12 per ton.

Exhibit 7.8: FT Fuel Price for Different Coal Types and Plant Configurations

Type of Co-Production Plant (price in $/barrel)	Reference Plant Using Bituminous Coal		Reference Plant Using Sub-bituminous Coal		Reference Plant Using Lignite Coal	
	Price of FT Fuel	Difference from Previous Price	Price of FT Fuel	Difference from Previous Price	Price of FT Fuel	Difference from Previous Price
Base Case	$ 72.83		$ 59.00		$ 76.00	
with CC&C	76.88	4.05	63.04	4.04	80.16	4.16
with Sequestration	82.83	5.95	68.73	5.69	86.35	6.19
with EOR	$ 73.07	$ (9.76)	$ 59.58	$ (9.15)	$ 76.00	$ (10.35)

The analysis shows that compression adds approximately $4 per barrel to the price of FT fuel from Reference Plants. Similarly, the cost of transporting, storing, and monitoring the carbon dioxide adds approximately $5.69 to $6.19 per barrel. The additional cost of transporting, storing, and monitoring the carbon dioxide is proportional to the amount of carbon dioxide produced by a plant and the percent captured. If capture rates are higher levels projected by Mitretek, the cost of FT fuel may increase by $0.50–$1.00 per barrel. Since a plant based on sub-bituminous coal produces the least carbon dioxide, it incurs the smallest amount of sequestration costs. The benefit of EOR revenues appears to largely offset the cost of sequestration, assuming a ready long-term carbon dioxide off-taker willing to pay $12 per ton.

The addition of carbon sequestration increases the price of FT fuel from a co-production plant using bituminous coal by 14 percent to $83 per barrel. Sequestration adds 16 percent (to $68.73 per barrel) and 14 percent (to $86.35 per barrel) to the price of FT fuel based on sub-bituminous coal and lignite, respectively.

III. Cost of Sequestration for Alternative Plants and Its Effect on Output FT Fuel Price, and the Effect of EOR

This section outlines the assumptions used to model a mid-sized (~30,000 BPD) bituminous coal co-production plant with increased net power and sequestration. The alternative configuration ("Alternative Plant with sequestration") builds upon the Alternative Plant detailed in Chapter 4. Specifically, the Alternative Plant with sequestration has added costs associated with compressing, transporting, geologically sequestering, and monitoring carbon dioxide captured during the gasification and FT processes. This section includes a discussion of the level of carbon dioxide emissions anticipated from the plant, as well as a detailed description of the basis for costs associated with the sequestration component.

In addition, as with the analysis of the Alternative Plant, this analysis examines the effects that an increase in electricity price will have on FT fuel price, as well as a discussion of the minimum FT fuel price required for the plant to sustain coverage of debt payments.

The discussion is organized in the following sections:

- Carbon Dioxide Emissions per Megawatt of Electricity Generated;
- Cost Assumptions for Sequestration;
- Plant Characteristics;
- Sources and Uses of Funds;
- Results of Price Analysis;
- Minimum Coverage Analysis; and
- Summary.

A. Carbon Dioxide Emissions per Megawatt of Electricity Generated

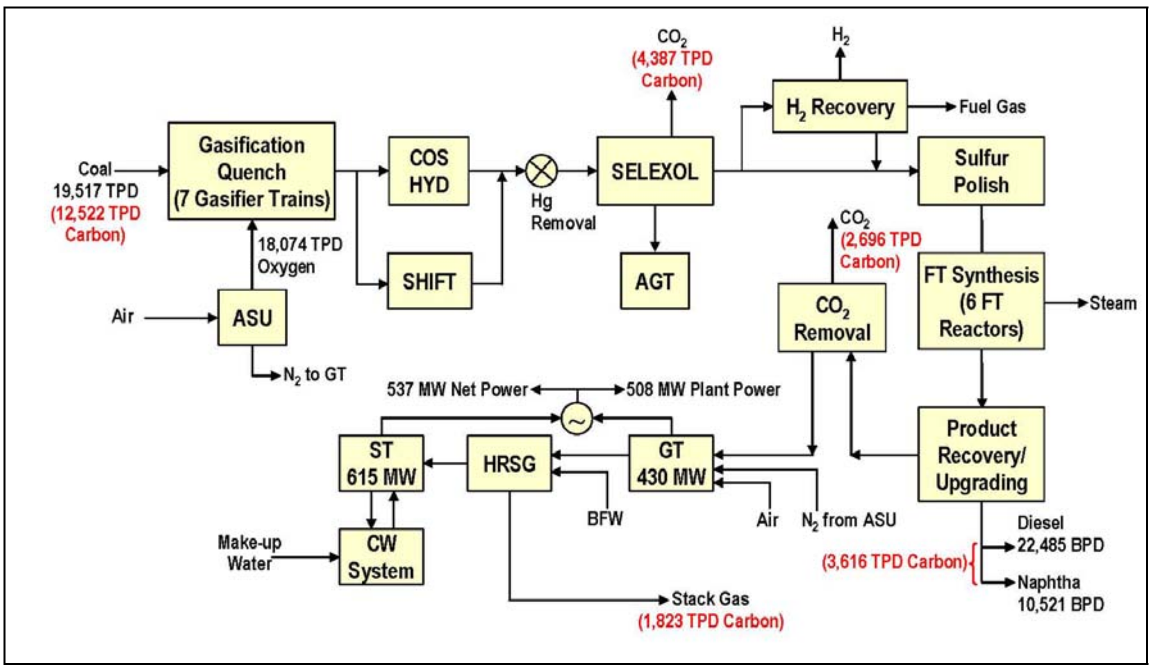
An important metric in analyzing carbon dioxide emissions from co-production plants is the generation of carbon dioxide per unit of output. As discussed earlier, the first step in determining this metric is to calculate the amount of energy production linked to FT fuel, naphtha, and net electricity output. The summation of these amounts will result in the total energy output of the plant. Then, to allocate proportionately the amount of carbon dioxide attributable to electricity production, the energy value of the output electricity has to be compared to the total energy output of the plant. The energy values of the major products as expressed in British thermal units (BTU) on a daily basis are as follows:

- **FT diesel:** FT diesel has 5.88 million BTU (MBtu) of energy per barrel. The plant produces 22,485 barrels of FT diesel per day and, hence, the energy value of FT diesel in a day is 132,212 MBtu (22,485 * 5.88).
- **Naphtha:** Naphtha has 5.248 MBtu of energy per barrel. The plant produces 10,521 barrels of naphtha per day and, hence, the energy value of naphtha in a day is 55,214 MBtu (10,521 * 5.248).
- **Electricity:** A megawatt-hour (MWh) of electricity has 3.412 MBtu of energy. The plant has a generating capacity of 1,045 MWe. Hence, the energy content in a day's production of electricity is 85,573 MBtu (1,045 * 24 * 3.412).

The combined energy contents of all three products equates to 272,999 MBtu (132,212 + 55,214 + 85,573). The percentage of energy that is attributable to electricity is therefore 31 percent (85,573 / 272,299).

The next step in determining the level of carbon dioxide emissions per unit of electricity output is to analyze the total amount of carbon dioxide to be emitted from the Alternative Plant with sequestration. Exhibit 7.9 provides an illustration from the AES Study of the carbon output of the increased power configuration.

Exhibit 7.9: Schematic and Carbon Balance for Alternative Plant with Sequestration



As the exhibit illustrates, the carbon dioxide generated per megawatt of electricity for the Alternative Plant with sequestration can be calculated by summing the total amount of carbon captured by the Selexol unit, captured after the FT process, and in the stack gas. This total amount is then applied to the net energy generated by the plant and multiplied by the percentage of total energy attributable to electricity, or 31 percent.

Exhibit 7.9 shows that carbon captured plus emitted from the Alternative Plant with sequestration total 8,906 (4,387 + 2,696 + 1,823) tons per day. Multiplying this figure by the molecular weight ratio of carbon dioxide (44) to carbon (12) provides the tons of carbon dioxide captured plus emitted per day, or 32,655 (8906 * 44 / 12) tons per day. Tons of carbon dioxide per day are then converted to pounds of carbon dioxide per day (1 metric ton = 2,204.6 lbs), resulting in total emissions of 71.99 million pounds of carbon dioxide per day (32,655 * 2,204.6). Electricity's share of emissions is the total plant emissions multiplied by the percentage of energy attributable to electricity, amounting to 22.32 million pounds per day (71.99 * 31 percent), less any carbon sequestered.

The Selexol unit and post-FT processing separate carbon dioxide from other streams, allowing the captured carbon to be compressed and transported. Current technology limits the capture to approximately 90–95 percent of total carbon from the gasification and FT processing steps; to be conservative, this analysis assumes 80 percent capture. Based upon these figures, the total carbon that may be captured from the Alternative Plant amounts to 5,666 (4,387 * 80% + 2,696 * 80%) tons per day. This amount equates to 20,777 (5,666 * 44 / 12) tons of carbon dioxide per day, or 45.8 million (20,777 * 2,204.6) pounds per day. (Higher capture rates, such as Mitretek assumes, would result in higher amounts captured.) Carbon dioxide emission levels can be determined by subtracting this amount from total plant emissions, resulting in 26.19 million pounds of carbon dioxide. Of this total, electricity is responsible for 8.11 (26.19 * 31%) million pounds of carbon dioxide emissions per day.

Finally, in order to determine the amount of carbon dioxide emissions per unit of output on a per MWh basis, the plant's daily emissions total is divided by the total amount of energy production attributable to electricity. This calculation results in carbon dioxide emissions of 2,032 pounds per MWh ($26.19 * 10^6 / 12,888$). If carbon dioxide emissions are instead pro-rated to the amount of energy production attributable only to electricity, the results on a per MWh basis are much lower: 630 lbs/MWh ($8.11 * 10^6 / 12,888$).

Exhibit 7.10 summarizes the carbon dioxide emissions for the Alternative Plant with sequestration.

Exhibit 7.10: Summary of Carbon Dioxide Emissions per Unit of Electricity Production for the Alternative Plant with Sequestration at 100 Percent Availability

Type of Co-Production Reference Plant	Alternative Plant with Sequestration	
Percentage of Carbon Dioxide Emissions Attributable to Net Electricity	All to Electricity	Prorated to Energy in Electricity
Total Carbon Output	3,240 tons/day	3,240 tons/day
Total CO_2 Output	11,880 tons/day	11,880 tons/day
Percentage of CO_2 Applied	100%	31%
CO_2 to be Applied to Net Electricity	11,880 tons/day	3,683 tons/day
in million lb/day	26.2 million lb/day	8.1 million lb/day
Net Electricity Output	537 MWh	537 MWh
Net Electricity in a Day	12,888 MWh/day	12,888 MWh/day
CO_2 Emissions Per Unit of Electricity	2,032 lb/MWh	630 lb/MWh

Sequestration may provide an opportunity for Alternative Plants to sell electricity in states that limit carbon dioxide production levels or give a dispatch preference to low-carbon dioxide electricity. For example, a law recently passed in California stipulates that utilities in California buy power under long-term contracts only from coal plants that emit less than 1,100 pounds of carbon dioxide per megawatt of electricity produced. Since the level of carbon dioxide emissions per unit of electricity generated by the Alternative Plant with sequestration falls below this limit, it may be eligible to sell electricity to California utilities.

B. Cost Assumptions for Sequestration

The previous section of this chapter provides in detail assumptions relating to capital costs, efficiency changes, and operating costs relating to sequestration for Alternative Plants. These costs include the cost of compressing the carbon dioxide produced in the plant, transporting it to a suitable geologic location, storing it in a suitable underground geologic formation, and monitoring the carbon dioxide in the geologic formation.

In building upon the Alternative Plant by incorporating these additional costs, Scully Capital used the same assumptions for sequestration of carbon dioxide produced in the Alternative Plants as it did for the Reference Plants.

C. Plant Characteristics

Most of the technical assumptions for the Alternative Plant with sequestration are the same as for the Alternative Plant. Since operation of the carbon compression equipment consumes some of the electricity produced, one significant difference is in the net power output of the plant. Exhibit 7.11 presents the technical assumptions for the Alternative Plant with sequestration and, for purposes of comparison, the technical assumptions for the Reference Plant that uses bituminous coal. Note that if capture rates are higher, more carbon dioxide can be available for sequestration.

Exhibit 7.11: Technical Assumptions for Alternative Plant with Sequestration

Type of Co-Production Plant	Bituminous Coal Reference Plant	Alternate Plant with Sequestration	% Change from Reference Plant
Input Characteristics			
Tons of Coal Per Day	17,987	19,517	8%
BTU Value of Bituminous Coal	11,800	11,800	
Price of Coal Delivered	$36 / Short Ton	$36 / Short Ton	
Output Characteristics @ Capacity			
FT Liquids (bpd)			
FT Diesel	24,359	22,485	-8%
Naptha	11,398	10,521	-8%
Total: FT Diesel-Equivalent	32,502	30,001	-8%
Electricity Production			
Gross (MWe)	725	1045	31%
Parasitic Load	468	508	8%
Net (MWe)	257	537	52%
Carbon Dioxide Captured (in tons/day)			
Input Carbon			
Carbon Captured in Processing	6,763	7,083	5%
In Fuel	3,918	3,616	-8%
In Stack Gas	860	1,823	53%
	11,541	12,522	8%
Carbon Captured	6,763	7,083	5%
at 90% Availability	6,087	6,375	5%
at 80% Capture	4,869	5,100	5%
in CO_2 Terms	17,854	18,699	5%
Plant Characteristics			
Efficiency (HHV)	48%	47%	-2%
Gasifier Trains	6	7	
Spare Gasifier	No	No	
FT Reactors	6	6	
Other Characteristics			
Construction Time	3 Years	3 Years	
Availability			
1st Year	51%	51%	
2nd Year	81%	81%	
3rd+ Year	90%	90%	

The net power output of the Alternative Plant with sequestration is less than that of the Alternative Plant (537 MWe versus 590 MWe). Parasitic load for the compression of captured carbon dioxide is approximately 53 MWe. Costs for sequestration activities also include additional equipment costs, as well as costs associated with carbon dioxide transport, storage, and monitoring.

D. Sources and Uses of Funds

Exhibit 7.12 presents the facility cost of the Alternative Plant with sequestration and associated financing costs under a non-recourse project financing structure.

Exhibit 7.12: Sources and Uses for Alternative Plant with Sequestration

SOURCE AND USES OF FUNDS ($000)

Alternative Plant with Sequestration

USES		SOURCES	
Facility Costs		**Gross Funding Requirements**	$ 3,762,156
Solids Handling & ASU	$ 459,055		
Gasification and FT	902,644		
Power Block + Gas Cleaning	721,014	Equity	1,128,647
Balance of Plant	372,164	Equity %	30%
Carbon Sequestration Equipment	-		
- Compression	54,561	Debt	2,633,509
- Transportation	63,836	Debt %	70%
Owner's Contingency	128,664		
License Fees & Startup Costs	105,359		
Design Costs	206,213		
Subtotal - Facility Costs	3,013,509		
		Debt Composition	
Financing Costs			
		Tranche A	2,633,509
Development Costs	62,940		100%
Closing Costs	50,000		
Debt Service Reserve Fund	149,425		
Capitalized Interest	486,282		
Subtotal - Financing Costs	748,647		
Gross Funding Requirements	**$ 3,762,156**	**Total Funds Drawn**	**$ 3,762,156**
Price of FT Fuel (@19% IRR)	**$ 83.47**	**Minimum DSCR**	**1.69**
Crude-Equivalent Price	**$ 64.21**	**Average DSCR**	**2.16**

Facility costs for the Alternative Plant with sequestration total $3.01 billion, approximately $130 million greater than the cost of the Alternative Plant. The increase in capital cost for this plant is largely attributable to the additional costs associated with the equipment for carbon compression and transportation, which total $118 million.

Sequestration also increases operating costs by approximately 9 percent and reduces net power production by 53 MWe due to the increase in parasitic load. The combination of higher capital and operating costs causes the price of FT fuel to rise to $83 (CEP: $64) per barrel, an increase of approximately $10 per barrel compared to the Alternative Plant. This significant increase in FT fuel price highlights the challenges associated with pursuing sequestration in a competitive market that lacks government-sponsored incentives and/or mandates for sequestration.

E. Results of Price Analysis

The price analysis examines how the addition of sequestration affects the Alternative Plant's insulation against fuel market downturns and how increased electricity production may affect sustainability of debt coverage.

The results of the analysis show that, assuming electricity prices fall within the prevailing market range of $59 per MWh to $70 per MWh, the range of FT fuel prices needed to achieve 19 percent IRR will be as low as $77 (CEP: $59) per barrel and as high as $83 (CEP: $64) per barrel. The FT fuel price needed rises for the Alternative Plant with sequestration because the revenues it generates from power sales will be reduced due to the parasitic load for carbon dioxide compression, which is estimated to consume 53 MWe. Simultaneously, operating costs increase with the addition of transport, storage, and monitoring of the carbon dioxide.

Although this FT fuel price is in the range of current market prices, it is well outside the credit agency long-term price assumption of $40, so the plant's exposure to fuel commodity price risk will raise credit concerns.

F. Minimum Coverage Analysis

The minimum coverage analysis determines the minimum FT fuel price at which a project can still service debt obligations. The results of this analysis for an Alternative Plant with sequestration should provide an indication of the degree of resilience that a plant would have against falling prices for FT fuels. The lower the FT fuel price at which a plant can sustain debt payments, the greater the level of insulation it has against price fluctuations in the fuel markets.

To test a plant's "breakeven" FT fuel price, Scully Capital calculated the FT fuel price at which debt coverage reaches 1.1x. As in the previous analysis, this scenario evaluated electricity prices in the range of $59–$70 per MWh. A high degree of insulation would be reached for the Alternative Plant with sequestration if the FT fuel price range, in crude-equivalent terms, is proximate to S&P's long-term oil price assumption of $40 per barrel.

The analysis projects that the Alternative Plant's FT fuel prices may range from as low as $53 (CEP: $40) per barrel to as high as $59 (CEP: $45) per barrel. Breakeven prices for the Alternative Plant with sequestration are considerably higher, by approximately 25 percent. As a result, the Alternative Plant with sequestration would be less insulated against decreases in oil prices than the Alternative Plant, and investors are likely to have a greater level of concern when they are considering its financeability.

G. Summary

The required FT fuel price for the Alternative Plant with sequestration increases significantly to $83 (CEP: $64) per barrel as a result of a decrease in power sales and an increase in operating costs tied to sequestration. The most notable cost is the increase in parasitic load to compress carbon dioxide, which reduces the plant's revenue stream from power sales. Operating costs also increase due to the transport, storage, and monitoring of sequestered carbon dioxide.

The sizeable increase in FT fuel price needed could limit the plant's competitiveness in fuel markets and be a credit concern for investors. Of further concern for investors in an Alternative Plant with sequestration is the decreased level of financial insulation against fuel market downturns that sequestration causes. Should oil prices fall below $40 per barrel, the Alternative Plant with sequestration will have no feasible way to support debt payments in the long term (i.e., after financial reserves are exhausted). As a result, the plant with an increased net power configuration will be unable to support carbon sequestration without the presence of incentives and/or some other mechanism for revenue enhancement.

IV. SENSITIVITY ANALYSIS FOR ALTERNATIVE PLANT WITH SEQUESTRATION

The sensitivity tests reported in this section compare the effect of fluctuations in key inputs to the Alternative Plant, without and with sequestration. To facilitate comparison of the sensitivity analysis results for the Alternative Plant with those of the Reference Plant (see Chapter 3), Scully Capital analyzed many of the same sensitivities in evaluating the Reference Plant and the Alternative Plant and in considering the impact of carbon dioxide sequestration on both plants. The analysis also considers the impact of EOR on both plants. The Reference Plant that uses bituminous coal is the basis of comparisons. Scully Capital conducted the following sensitivity tests for the Alternative Plant without and with sequestration:

- Increase/Decrease in Plant Capital Costs;
- Increase/Decrease in the Price of Coal;
- Plant Naphtha to Diesel Production Ratio of 15:85;
- Increase/Decrease in Interest Rates;
- Increase/Decrease in Plant Availability Rates;
- Acceleration/Delay in Construction Period; and
- Increase/Decrease in Carbon Dioxide Storage Costs for Alternative Plant with Increased Net Power and Sequestration.

A. Increase/Decrease in Plant Capital Costs

Reflecting the considerable degree of uncertainty associated with cost assumptions for co-production plants, Scully Capital modeled a 25 percent increase and decrease in plant capital costs. The results of these sensitivity tests represent the upper and lower bounds for the range of anticipated FT fuel prices. Exhibit 7.13 summarizes the results for each sensitivity test.

Exhibit 7.13: Increase and Decrease in EPC Costs for the Alternative Plant and the Alternative Plant with Sequestration

FT Fuel Price Results ($ per barrel)	Alternative Plant		Alternative Plant with Sequestration	
	25% Change in EPC Costs		25% Change in EPC Costs	
	Increase	Decrease	Increase	Decrease
FT Diesel Price	$89.90	$55.75	$101.57	$65.77
Crude-Equivalent Price	$69.15	$42.88	$78.13	$50.59
Change from Base Plant	$17.25	-$16.90	$18.10	-$17.70
% Change from Base Plant	23.7%	-23.3%	21.7%	-21.2%

The economics of both the Alternative Plant and the Alternative Plant with sequestration appear to be highly sensitive to changes in capital costs. Specifically, a 25 percent increase/decrease in EPC costs equates to a nearly equivalent percentage change in FT fuel price, a linear relationship.

B. Increase/Decrease in the Price of Coal

As in the analysis of the Reference Plants, the input price of bituminous coal was increased to $48 per short ton ($2.04/MMBtu) and decreased to $24 per short ton ($1.02/MMBtu) from the base case price of $36 per short ton ($1.53/MMBtu).

Changes in FT fuel price for both the Alternative Plant and the Alternative Plant with sequestration display greater sensitivity to coal price than those of the Reference Plant. This greater sensitivity occurs because Alternative Plants use more coal to generate the increased electricity output. Exhibit 7.14 provides the results of the analysis of coal price changes.

Exhibit 7.14: Increase and Decrease in Price of Coal for the Alternative Plant and the Alternative Plant with Sequestration

FT Fuel Price Results ($ per barrel)	Alternative Plant		Alternative Plant with Sequestration	
	33% Change in Coal Prices		33% Change in Coal Prices	
	Increase	Decrease	Increase	Decrease
FT Diesel Price	$83.32	$61.95	$94.15	$72.80
Crude-Equivalent Price	$64.09	$47.65	$72.42	$56.00
Change from Base Plant	$10.67	-$10.70	$10.68	-$10.67
% Change from Base Plant	14.7%	-14.7%	12.8%	-12.8%

The exhibit shows that a 33 percent change in the price of coal causes a change in the price of FT diesel of approximately 15 percent for the Alternative Plant and 13 percent for the Alternative Plant with sequestration. The additional quantities of coal required by the Alternative Plants makes them more sensitive to coal price changes than the Reference Plant, for which a 33 percent change in the price of coal causes a 13 percent change in the price of FT fuels.[14] This analysis also confirms the conclusion that coal price plays a greater role for the Alternative Plant in the determination of FT fuel price.

C. Plant Naphtha to Diesel Production Ratio of 15:85

As discussed in the analysis of Reference Plants, recent innovations in FT reactor technology make it possible to reduce the percentage of naphtha fuel produced by co-production plants from 25 percent to 15 percent of total energy production. While this technology is not yet widely used commercially, it may prove to be a major technological breakthrough with positive financial implications because naphtha commands a significantly lower price in the marketplace than FT diesel. Thus, a plant can be more profitable if it reduces the percentage of naphtha as a part of total fuel production.

If an Alternative Plant were to run at 100 percent availability, it would produce 25,501 barrels per day of FT diesel and 4,500 barrels per day of naphtha verses the base case mix for the Alternative Plant of 22,501 barrels per day of FT diesel and 7,500 barrels per day of naphtha. Exhibit 7.15 below displays the results of a decrease in the percentage of naphtha production from 25 percent to 15 percent of total energy output.

[14] See Chapter 3 for results of Reference Plant analysis.

Exhibit 7.15: Decrease in Naphtha Production for the Alternative Plant and the Alternative Plant with Sequestration

FT Fuel Price Results ($ per barrel)	Alternative Plant	Alternative Plant with Sequestration
	15% Naphtha Production	15% Naphtha Production
FT Diesel Price	$68.98	$78.55
Crude-Equivalent Price	$53.06	$60.42
Change from Base Plant	-$3.67	-$4.92
% Change from Base Plant	-5.1%	-5.9%

A reduction in naphtha production levels from 25 percent to 15 percent results in a decrease in the price for FT fuel of approximately 5 percent for the Alternative Plant and approximately 6 percent for the Alternative Plant with sequestration. The Reference Plant FT fuel price changes by 5 percent in response to the same change in naphtha production rate. This result rests on the assumption that the cost of technology enabling these reductions and its associated operating costs are comparable to those used in the Reference Plant.

D. Increase/Decrease in Interest Rates

As with the Reference Plant, Scully Capital modeled a 25 percent change in the plant's interest rate by increasing and decreasing the Alternative Plant's interest rate to 10 percent and 6 percent, respectively, from the base case rate of 8 percent. The 2 percent (200 bps) change in interest rates represents a 25 percent change from the Reference Plant. Exhibit 7.16 presents the results of these changes in interest rates.

Exhibit 7.16: Increase and Decrease in Interest Rates for the Alternative Plant and the Alternative Plant with Sequestration

FT Fuel Price Results ($ per barrel)	Alternative Plant		Alternative Plant with Sequestration	
	25% Change in Interest Rate		25% Change in Interest Rate	
	Increase	Decrease	Increase	Decrease
FT Diesel Price	$77.92	$67.85	$88.97	$78.48
Crude-Equivalent Price	$59.94	$52.19	$68.44	$60.37
Change from Base Plant	$5.27	-$4.80	$5.50	-$4.99
% Change from Base Plant	7.3%	-6.6%	6.6%	-6.0%

The analysis shows that this 25 percent change in interest rates causes FT fuel price to change by approximately 7 percent for the Alternative Plant and approximately 6 percent for the Alternative Plant with sequestration. The asymmetry of these changes for the two Alternative Plants is due to the nature of mortgage-style payments in which the payment per year is kept constant but principal payments and interest payments vary. The same change in interest rates causes a change of about 5.5–6 percent for the Reference Plant. A lower interest rate allows for lower capitalized interest and a smaller debt service reserve fund. These results indicate that interest rates can have a material affect on FT fuel prices. As with the Reference Plant, it appears that changes in coal and EPC costs have a greater effect on FT diesel pricing than do interest rates for Alternative Plants without and with sequestration.

E. Increase/Decrease in Plant Availability Rates

Scully Capital varied plant availability rates in two dimensions in the sensitivity analyses for all of the plants considered. In one dimension, it modeled an increase to 95 percent and a decrease to 85 percent in the *final availability* assumption of 90 percent. This 5 percent change represents an average change in final availability of 5.56 percent over the life of the plant. Scully Capital also adjusted the three-year *ramp-up period* for operations at a new plant. For the scenario with an increase in availability, the three-year ramp-up increases to 60 percent in year one, 85 percent in year two, and 95 percent in year three. In the decreased availability scenario, the ramp-up incorporates 45 percent availability for the first year, 65 percent for the second year, and 85 percent for the third year. Exhibit 7.17 presents the results of this analysis.

Exhibit 7.17: Increase and Decrease in Final Availability for the Alternative Plant and the Alternative Plant with Sequestration

FT Fuel Price Results ($ per barrel)	Alternative Plant		Alternative Plant with Sequestration	
	5% Change in Final Availability		5% Change in Final Availability	
	Increase	Decrease	Increase	Decrease
FT Diesel Price	$67.88	$79.33	$78.52	$90.42
Crude-Equivalent Price	$52.22	$61.02	$60.40	$69.55
Change from Base Plant	-$4.77	$6.68	-$4.95	$6.95
% Change from Base Plant	-6.6%	9.2%	-5.9%	8.3%

Even small changes in availability have a large effect on the price of FT fuel. For a 5.56 percent increase in final availability, the change in price for FT fuel declines by about 7 percent for the Alternative Plant and 6 percent for the Alternative Plant with sequestration. An equivalent decrease in final availability for the two plants causes approximately a 9 percent and 8 percent increase in final FT fuel price. Significantly, increases in availability directly increase the net cash flow from the project. As noted earlier, capital cost changes have a greater affect on pricing of FT fuel than operating costs. Changes in availability neither affect capital costs nor produce net cash flow after accounting for variable operating costs. As a result, on a percentage basis, changes in availability produce a greater percentage effect than changes in capital costs. These results, therefore, suggest that the final price of FT fuel will be highly dependent upon the operational performance of a co-production plant without or with sequestration.

F. Acceleration/Delay in Construction Period

As with the Reference Plants, two scenarios examine the effect of varying construction time for Alternative Plants, without and with sequestration, from the base case estimate of 3 years. In the first scenario, construction time increases by 12 months to 4 years. In the second scenario, the construction time decreases by 6 months to 2.5 years. A 12-month delay represents a 33 percent change from the base construction time, while an acceleration of six months represents a 17 percent change.

In the accelerated scenario, debt repayment occurs in the same time frame as in the Reference Plants and Alternative Plant without sequestration (after a year of interest capitalization during the ramp-up period) and with the same 6-month interest-only period. For the scenario with a one-year increase in construction time, all project costs are expended in the 3-year reference time frame, an extra year of interest capitalization is added, and debt amortization is delayed by a year. Exhibit 7.18 summarizes the results of this analysis.

Exhibit 7.18: Increase and Decrease in Construction Period for the Alternative Plant and the Alternative Plant with Sequestration

FT Fuel Price Results ($ per barrel)	Alternative Plant		Alternative Plant with Sequestration	
	Change in Construction Time		Change in Construction Time	
	Acceleration	Delay	Acceleration	Delay
FT Diesel Price	$68.85	$80.55	$79.52	$91.72
Crude-Equivalent Price	$52.96	$61.96	$61.17	$70.55
Change from Base Plant	-$3.80	$7.90	-$3.95	$8.25
% Change from Base Plant	-5.2%	10.9%	-4.7%	9.9%

This analysis shows that FT fuel price is significantly sensitive to changes in construction time. A one-year delay results increases the price of FT fuels by approximately 11 percent for the Alternative Plant and approximately 10 percent for the Alternative Plant with sequestration. An acceleration of six months, in contrast, results in a decrease in FT fuel price of approximately 5 percent for both alternative plants.

The analysis also reveals that the non-linear relationship between schedule and FT fuel price arises from the effect of compounding interest. The analysis does not consider any additional costs associated with the possible financing required for a construction delay.

G. Increase/Decrease in Carbon Dioxide Storage Costs

Since the cost of carbon dioxide storage will vary based upon a number of site-specific factors, Scully Capital analyzed the impact of variations in this cost to a plant's required FT fuel price and long-run financial viability. (While the transportation, storage, and monitoring of carbon dioxide in a sequestration operation is likely to be a separate business external to a co-production plant, these costs are added to the plant's capital and operating costs for comparative purposes in this analysis.) To accomplish this analysis, then, Scully Capital built on the analysis of the Reference Plant, without and with carbon capture and sequestration, and the Alternative Plant, without and with carbon capture and sequestration, by varying the capital and operating costs for transportation, storage, and monitoring of sequestered carbon dioxide by 50 percent.

Scully Capital estimates a storage cost of $4.78 per ton of carbon dioxide for the Alternative Plant with sequestration (see Section II.B. of this chapter). This sensitivity test modeled scenarios that incorporate this 50 percent decrease and increase in carbon dioxide storage costs, resulting in a per ton of carbon dioxide storage cost of $2.39 and $7.17, respectively. Exhibit 7.19 summarizes the results of the sensitivity tests.

Exhibit 7.19: Increase and Decrease in Carbon Dioxide Storage Costs for the Alternative Plant with Sequestration

FT Fuel Price Results ($ per barrel)	Alternative Plant with Sequestration	
	Change in CO_2 Storage Cost	
	Increase	Decrease
FT Diesel Price	$85.65	$81.32
Crude-Equivalent Price	$65.88	$62.55
Change from Base Plant	$2.18	-$2.15
% Change from Base Plant	2.6%	-2.6%

The results of the analysis show that FT fuel price for the Alternative Plant with sequestration is not sensitive to changes in carbon dioxide storage costs. A 50 percent increase and decrease in the cost to store carbon dioxide results in a 3 percent increase and decrease in FT fuel price, respectively. As a result, once carbon dioxide sequestration is assumed, it appears that carbon dioxide storage costs have considerably less influence upon FT fuel prices than availability rates, capital costs, and coal prices.

H. Summary

This section provides the results of an analysis of the impact of sensitivity testing on major inputs to FT fuel price and the overall economic viability of a co-production Alternative Plant with sequestration. (See Chapter 4 for a similar analysis of Alternative Plants that do *not* sequester carbon dioxide.) Exhibit 7.20 summarizes these results, which offer important insights into the prospects for early commercial co-production plants.

Exhibit 7.20: Summary of Analytical Results for the Alternative Plant with Sequestration

		Alternative Plant with Sequestration		
		Value: +	**Value: -**	
Summary of Analyses	**Value Change**	Price of FT Fuel (CEP) $/bbl	Price of FT Fuel (CEP) $/bbl	**% Change in Price from Base Case**
Base Case Fuel Price		**FT Diesel = $83.47, CEP = $64.21**		
Debt Coverage	1.1x	$59 ($45)		
Electricity Price	+ 25%	$77 ($60)		
Sensitivity Testing				
EPC Costs	+/- 25%	$102 ($78)	$66 ($51)	+ / - 21.7%
Coal Cost	+/- 33%	$94 ($72)	$73 ($56)	+ / - 12.8%
Reduced Naphtha Output	15% of output	-	$79 ($60)	- 5.9%
Interest Rates	+/- 25%	$89 ($68)	$78 ($60)	+6.6% / -6.0%
Final Availablity	+/- 5%	$79 ($60)	$90 ($70)	-5.9% / +8.3%
Construction Time	+1 Year/ -6 months	$92 ($71)	$80 ($61)	+9.9% / -4.7%
CO_2 Storage Costs	+/- 50%	$86 ($66)	$81 ($63)	- / + 2.6%

The sensitivity testing of Alternative Plants with sequestration shows that variations in plant availability, capital cost, coal cost, output prices, technical design, and construction time all have material impacts on the price of FT fuel, while carbon dioxide storage costs do not. The analysis makes it clear that the most significant risks to the economic viability of an Alternative Plant occur due to market price risk associated with crude oil-based products, high capital cost, and integration risk.

A number of strategies, however, can mitigate these risks. Chapter 5 provides details concerning the probability that such risks will arise and outlines current approaches used in the marketplace to address these various risk factors. Chapter 6 provides the results of analyses of the value and cost of incentives for the construction and operation of co-production plants, and the next section of this chapter provides an analysis of what is, perhaps, the optimal incentive for sequestration.

V. IMPACT OF INCENTIVES FOR SEQUESTRATION

This section analyzes the effect of a tax credit geared to encourage sequestration. Scully Capital selected a tax credit for this analysis that is based on the amount of carbon sequestered. This type of incentive is potentially unique in that it can be structured to actively encourage sequestration operations associated with large facilities, such as co-production projects; it also complements incentives that encourage the construction of early commercial co-production plants. Payment of the tax credit would be on the basis of the volume of carbon dioxide sequestered. No payment would be made unless carbon dioxide is actually sequestered.

Scully Capital considered other potential incentives in addition to a tax credit based on the amount of carbon sequestered:

- Investment tax credits can be structured to create an incentive to *construct* facilities that have the capacity to sequester carbon, but once a facility has been constructed and the tax credit paid, they do not create an ongoing incentive to *operate* the sequestration facilities.
- Credit incentives can both improve the prospects of obtaining financing for a facility capable of sequestering carbon and reduce the cost of borrowing, but they would not, as currently practiced, obligate a project to actually sequester carbon dioxide produced in the facility. (It may be possible, however, to structure a credit enhancement so that the project sponsor could potentially be required to sequester carbon dioxide as a condition of the execution of the instrument. In this case, though, the project sponsor could potentially refinance the project at a later point and no longer be subject to the original conditions of the credit enhancement.)

Previous sections of this chapter present the results of an analysis of the cost implications of sequestration, concluding that sequestration may increase the cost of FT fuel by 14–16 percent for both Reference Plants and Alternative Plants. Given the projected price of FT fuel and the volatility of oil markets, this increase in the price of FT fuel to accommodate both sequestration and 19 percent IRR is material; an increase of this magnitude to “breakeven” pricing represents a challenge in financing the project.

This section describes the type of tax credit that would encourage sequestration, evaluates the level of tax credit that would make sequestration “return neutral,” identifies the effect the tax credit would have on EOR operations, and finally presents sensitivity testing results. The section is divided into the following parts:

- Description of an Incentive to Sequester;
- Level and Cost of Sequestration Incentive;
- Effect on EOR with Sequestration; and

- Sensitivity Testing for Sequestration.

A. Description of an Incentive to Sequester

The cost of sequestration consists of such capital costs as compressors, pipelines, and wells, plus operating costs associated with compressing, transporting, injecting, and monitoring the carbon dioxide. An investment-based tax credit would decrease the effective cost of installing the equipment but, regardless of a requirement to sequester, would not create an incentive to operate the sequestration equipment. Similarly, a credit-based incentive would improve prospects for obtaining financing for the entire project and decrease financing costs the project, but it would not create an incentive for carbon dioxide sequestration.

On the other hand, an incentive that provides monetary benefits only if carbon dioxide is sequestered would promote sequestration. The more carbon that is sequestered, the more a plant's owners would be paid. To accomplish this effect, a tax incentive would have to be set at a level sufficient to cover not only the operating costs of sequestration, but also to provide investment returns on sequestration equipment at the project's weighted average cost of capital. Thus, the level of the tax incentive would be affected by the operating performance of the plant, as well as the capital cost of the sequestration equipment.

The analysis assumes that the tax credit could be monetized in a manner similar to the way a production tax credit offered to wind-based electricity can be monetized, allowing the project owner to raise tax equity. A tax credit based on tons of carbon dioxide sequestered would be tied directly to actual sequestration. This approach ensures that the project developer or other private-sector participants in the project accept the technology and integration risk associated with making carbon capture, compression, transportation, and sequestration work and that they have convinced the capital markets they can do it. Thus, a tax incentive of this type differs from an investment tax credit, in which the tax credit is received upon placing the asset in service.

B. Level and Cost of Sequestration Incentive

This section reports the results of an analysis that describes the level of a tax incentive needed to obtain the price of FT fuel for the Reference Plant using each of the three types of coal. Key assumptions include:

- The incentive lasts for 10 years;
- The plant continues to sequester the carbon dioxide after the tax credit expires;
- The incentive is applicable for all of the carbon dioxide output of the plant that is sequestered; and
- The value of the incentive is not indexed to inflation.

In addition, while the transportation, storage, and monitoring of carbon dioxide in a sequestration operation is likely to be a separate business external to a co-production plant, for comparative purposes the analyses treats the sequestration operation as integral with the co-production project. The costs of the sequestration operation are therefore added to the plant's capital and operating costs, rather than being treated separately, and the project benefits from the tax incentive directly.

To understand the benefits of the tax incentive, it is also necessary to understand its cost to the government. Cost to the government is quantified as the "budgetary impact." For tax-based incentives, Scully Capital estimates budgetary impact based on the revenues lost to the U.S. Treasury as a result of the incentive over the standard 10-year window used for budget analyses and legislative proposals ("10 Year Budget Window"). For comparison purposes, Scully Capital assumes that the budget window and the start of production would coincide. This assumption results in the production and budget window beginning in FY 2009 and ending in FY 2018. It should be noted that the budgetary impact and the total cost of the incentive over the life of a project are not necessarily equal when the incentive affects cash flow beyond the budget window, as in the case of accelerated depreciation. The total cost of an incentive over the life of the project to the government is identified as "total costs." The benefit of a tax incentive depends on the ability of project sponsors to use tax credits and tax losses to offset their tax liability. The budgetary impact of tax incentives is calculated on the cash flow over a fixed period of time (i.e., on a dollar-for-dollar basis).

To obtain the level of incentive required to encourage sequestration, Scully Capital held the FT price at the level of the Reference Plants with 19 percent IRR and allowed IRR to float. The increase in project capital and operating costs causes the project's IRR to decrease. Scully Capital then increased the value of the tax incentive per ton of carbon dioxide sequestered until 19 percent IRR was again achieved. Exhibit 7.21 provides the incentive value needed to achieve the price of FT fuel from this base case analysis and to determine the budgetary impact and total cost of the incentive.

Exhibit 7.21: Value of Tax Incentive ($/ton) to Achieve Reference Plant FT Fuel Prices

	Bituminous Reference Plant	Sub-bituminous Reference Plant	Lignite Reference Plant
Price of FT Fuel with Sequestion	$82.83 /bbl	$68.73 /bbl	$86.35 /bbl
Price of FT Fuel after Incentive	$72.83 /bbl	$59.00 /bbl	$76.00 /bbl
Incentive Value	$10.90 /ton	$11.30 /ton	$10.63 /ton
Budgetary Impact ($ millions)	$672	$643	$694
Total Cost ($ millions)	$672	$643	$694

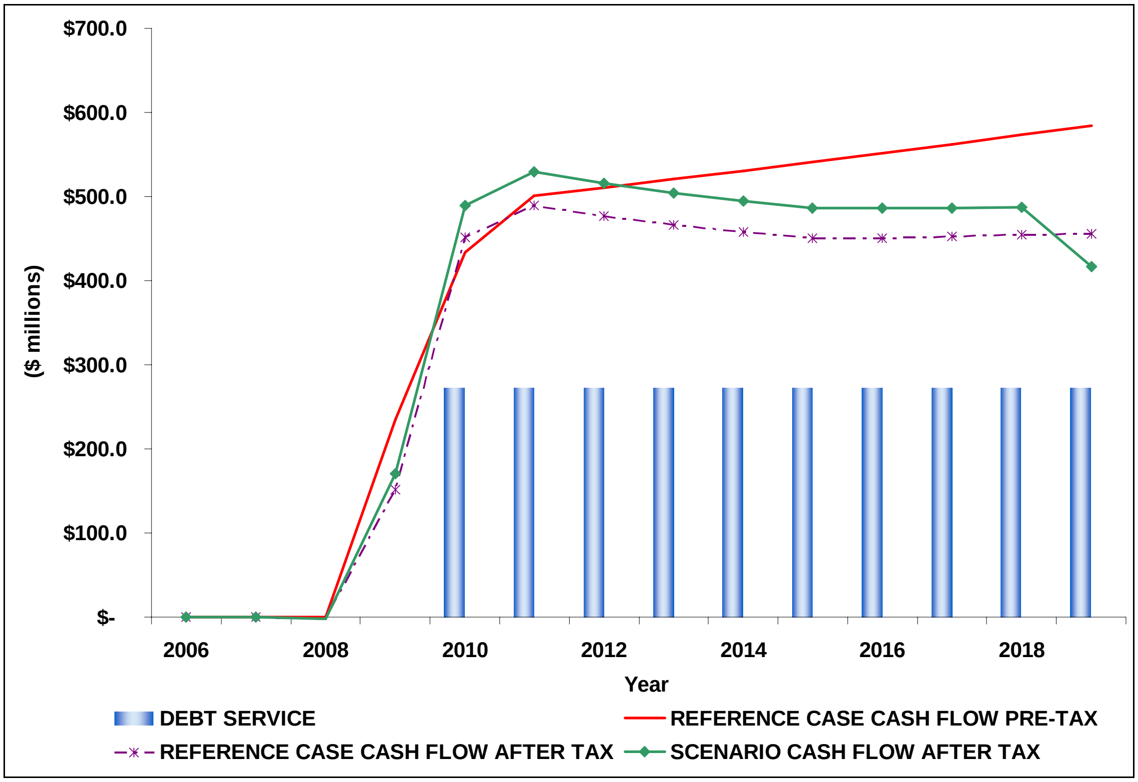
The base case analysis shows that a tax incentive in the range of $10.63 per ton to $11.30 per ton of carbon dioxide sequestered is required to offset the cost increases from sequestration. The range of values provides a number of important insights:

- The cost of sequestration is site-specific and design-specific. The value of an incentive intended to promote sequestration will determine which sites and projects are economically feasible and which are not.
- It would be difficult to design (and more difficult to gain approval for) an incentive that covers exactly the cost of sequestration on an individual plant basis. So, some co-production plants will receive more of an economic boost from the tax credit than others and some other types of energy projects will receive more or less of an economic boost than an average co-production plant.
- Without a regulatory driver for sequestration or an adequate tax on carbon emissions, a plant owner could decide to stop sequestering the carbon dioxide from a plant after the completion of the tax credit.
- The tax incentive level for early commercial co-production projects with carbon dioxide sequestration should cover the economic cost of installing and operating sequestration equipment and also provide an incentive for investors to assume technology, liability, and integration risks associated with the sequestration.

Because the budgetary window and the life of the tax incentive coincide, the budgetary impact and the total cost of an incentive are the same: They range from $643 million to $694 million over a 10-year period. The cost of the incentive depends on the amount of carbon dioxide sequestered, which is lowest for a plant that uses sub-bituminous coal and highest for a plant that uses lignite.

Exhibit 7.22 presents the impact of the tax incentive on the cash flow of a project. The exhibit shows the pre-tax and post-tax cash flow (i.e., the cash flow benefit) for the bituminous coal-based Reference Plant with sequestration, along with the post-tax cash flow of the base case. The project benefits from enhanced cash flow in earlier years, when the value of and need for the cash flow is the greatest. The graph shows that debt service is met adequately on both a pre-tax and post-tax basis. The graphs for co-production plants using sub-bituminous coal and lignite would be similar.

Exhibit 7.22: Graph of Cash Flows for a Tax Credit for Tons of Carbon Dioxide Sequestered



C. Effect of EOR with Sequestration

Scully Capital also analyzed whether and to what extent the combination of a tax credit and EOR with sequestration could benefit a project. The analysis assumes that a tax credit of $11.30 per ton of carbon dioxide is available for all qualifying projects. This amount corresponds to the largest tax credit needed to make sequestration work for any of the three Reference Plants with sequestration. At this level, the tax credit would offset slightly more than the sequestration costs for co-production plants using bituminous coal and lignite.

To analyze this scenario, Scully Capital applied the tax incentive to a Reference Plant with sequestration and EOR and decreased the price of FT fuel until a 19 percent IRR was achieved. Exhibit 7.23 provides the results of the analysis.

The analysis shows that a 14–16 percent decrease in the price of FT fuel produced in a Reference Plant using bituminous coal would be possible from the combined benefits of EOR revenues and the tax incentive. For a Reference Plant using sub-bituminous coal, the price of FT fuel needed to achieve a 19 percent IRR decreases to the range $50 (CEP: $38) and, for a lignite-based Reference Plant, it declines to $65 (CEP: $50) per barrel.

The amount of carbon dioxide sequestered differs by plant type and operating performance, along with the budgetary impact and total cost of the incentive. For a plant that has 90 percent availability and an 80 percent capture rate, the budgetary impact and total cost vary from $643–$733 million and are proportional to the dollar decrease in FT fuel price. If the Reference Plant that uses bituminous coal performs at the higher capture rate assumed by Mitretek, the budgetary impact and total cost of the tax incentive could increase by approximately $160 million.

Exhibit 7.23: Effect of EOR with Sequestration and Tax Incentive on Three Reference Plants with Sequestration

	Bituminous Reference Plant	Sub-bituminous Reference Plant	Lignite Reference Plant
Reference Case Price of FT Fuel	$72.83 /bbl	$59.00 /bbl	$76.00 /bbl
Price of FT Fuel after Incentive and EOR benefits	$62.68 /bbl	$49.85 /bbl	$64.98 /bbl
Crude-Equivalent Price	$48.22 /bbl	$38.35 /bbl	$49.98 /bbl
Difference from Reference Case	-$10.15, -14%	-$9.15, -16%	-$11.02, -15%
Incentive Value	$11.30 /ton	$11.30 /ton	$11.30 /ton
Budgetary Impact ($ millions)	$697	$643	$738
Total Cost ($ millions)	$697	$643	$738

D. Sensitivity Testing for Sequestration

Scully Capital performed sensitivity tests to consider the impact of fluctuations in key inputs associated with sequestration and the level of the tax credit. The analysis is focused on changes in FT fuel prices, and it targets 19 percent IRR for all three Reference Plants. The modeling observed the effects of the following:

- An increase or decrease in the cost to store carbon dioxide;
- An increase or decrease in the price of carbon dioxide for EOR; and
- An increase or decrease in the duration of the tax incentive for sequestration.

The first sensitivity test assessed the impact of changes in the cost per ton to store carbon dioxide. Since this cost is highly dependent on a variety of factors, including plant location, topology, and characteristics of available storage sites, it is difficult to assume a uniform cost for this input. As a result, Scully Capital modeled both upward and downward deviations from the assumed storage cost. The second test considers the effects that changes in the price of carbon dioxide sold for use in EOR applications have on plant revenue. Since the price of carbon dioxide could vary by location and be dependent on market conditions, this sensitivity test measures the effect that fluctuations in carbon dioxide pricing may have on project economics. The final sensitivity case seeks to determine the duration and level of a tax credit that both minimizes budgetary impact and encourages plant owners to sequester carbon dioxide.

The level of tax credit required to achieve 19 percent IRR is different for each type of co-production plant, but to understand the impact of the variables evaluated in the sensitivity tests, it was preferable to keep the level of tax credit constant. As a result, the first two sensitivity tests evaluate the impact of a 10-year tax credit of $11.30 per ton of carbon dioxide that is based on the highest level of tax credit required by any of the three Reference Plant designs to offset the costs of sequestration.

1. Increase/Decrease in the Cost to Store Carbon Dioxide

Since the cost of carbon dioxide storage will vary based upon a number of site-specific factors, Scully Capital analyzed the impact of variations in storage cost to the required FT fuel price and long-run financial viability of a Reference Plant. The base case analysis for sequestration assumes a storage cost of $4.78 per ton of carbon dioxide. The sensitivity tests modeled scenarios for each Reference Plant in which per ton carbon dioxide storage costs decrease or increase by 50 percent. This cost range results in a storage cost of $2.39 and $7.17, respectively, per ton of carbon dioxide. In addition, the test incorporated the $11.30 per ton tax credit for carbon dioxide sequestered for 10 years to illustrate the combined effect of these factors on FT fuel price.

Exhibit 7.24 depicts the changes to the FT fuel price for each Reference Plant from these sensitivity tests:

Exhibit 7.24: Sensitivity Tests of Increased/Decreased Carbon Dioxide Storage Costs with a 10-year, $11.30/ton Tax Credit

($ per barrel)	Base Case with Sequestration; Storage Costs at $2.39/ton; 10-Year Tax Credit at $11.30/ton	Base Case	Base Case with Sequestration; Storage Costs at $7.17/ton; 10-Year Tax Credit at $11.30/ton
Bituminous Reference Plant			
FT Diesel Price	$70.46	$72.83	$74.45
Crude-Equivalent Price	$54.20	$56.02	$57.27
Change from Base Case	-$2.37		$1.62
% Change from Base Case	-3%		2%
Sub-Bituminous Reference Plant			
FT Diesel Price	$57.15	$59.00	$60.87
Crude-Equivalent Price	$43.96	$45.38	$46.82
Change from Base Case	-$1.85		$1.87
% Change from Base Case	-3%		3%
Lignite Reference Plant			
FT Diesel Price	$73.22	$76.00	$77.46
Crude-Equivalent Price	$56.32	$58.46	$59.58
Change from Base Case	-$2.78		$1.46
% Change from Base Case	-4%		2%

The analysis indicates that fuel prices fluctuate similarly for the three Reference Plants with the addition of long-term storage of carbon dioxide. Both a 50 percent increase and a 50 percent decrease in the cost per ton to store carbon dioxide result, on average, in the need for a 2–3 percent increase and 3–4 percent decrease in the FT fuel price required to achieve 19 percent IRR.

It appears, however, that the price of FT fuel produced in the Reference Plants that use bituminous coal and lignite will be slightly more sensitive on a dollar basis to fluctuations in per ton storage costs than FT fuel produced in a plant that uses sub-bituminous coal. This effect is most likely due to the fact that the engineering designs used in this study project that higher levels of carbon dioxide will be produced by plants that use bituminous coal and lignite. Greater emissions not only translate into higher overall storage costs but also to greater price elasticity to changes in carbon dioxide storage costs, or generally, any emissions-dependent input.

In addition, it should be noted that a 50 percent increase in per ton storage costs, even with a tax credit, results in fuel prices that exceed those in the base case. This scenario shows that the impact on project economics of a level tax credit across all types of Reference Plants will vary with site-specific conditions and engineering design.

2. Increase/Decrease in the Price of Carbon Dioxide for EOR

Absent a long-term off-take agreement, the off-take of carbon dioxide may vary over the lifetime of a project as the price of carbon dioxide fluctuates with globally determined oil prices and other factors. Further, off-takers of carbon dioxide for EOR operations may not have a sufficiently high credit rating, creating a credit risk with regard to the materialization of revenues. As a result of these uncertainties, in this sensitivity test Scully Capital analyzed the ramifications of carbon dioxide price fluctuations on resulting fuel prices.

In this sensitivity test, Scully Capital assumes that plant owners will sell their captured and compressed carbon dioxide to buyers who sequester it in EOR projects. The base case analysis with EOR assumes that the price obtained for carbon dioxide is $12 per ton. The sensitivity analysis models the effects of a 33 percent decrease and 33 percent increase in this price, resulting in $8 per ton and $16 per ton carbon dioxide pricing. The analysis also incorporates the tax credit to determine the combined effects of these inputs on FT diesel fuel price. Exhibit 7.25 displays the results of the analysis, reflecting changes in the minimum FT diesel fuel price required to attain a 19 percent IRR.

Exhibit 7.25: Sensitivity of FT Fuel Prices to the Price of Carbon Dioxide for EOR with a 10-year, $11.30 per Ton Tax Credit

($ per barrel)	Base Case with EOR; CO_2 Price at $8/ton; 10-Year Tax Credit at $11.30/ton	Base Case	Base Case with EOR; CO_2 Price at $16/ton; 10-Year Tax Credit at $11.30/ton
Bituminous Reference Plant			
FT Diesel Price	$65.95	$72.83	$59.42
Crude-Equivalent Price	$50.73	$56.02	$45.71
Change from Base Case	-$6.88	$0.00	-$13.41
% Change from Base Case	-9%	0%	-18%
Sub-Bituminous Reference Plant			
FT Diesel Price	$52.90	$59.00	$46.80
Crude-Equivalent Price	$40.69	$45.38	$36.00
Change from Base Case	-$6.10	$0.00	-$12.20
% Change from Base Case	-10%	0%	-21%
Lignite Reference Plant			
FT Diesel Price	$68.44	$76.00	$61.52
Crude-Equivalent Price	$52.65	$58.46	$47.32
Change from Base Case	-$7.56	$0.00	-$14.48
% Change from Base Case	-10%	0%	-19%

Fluctuations in the price of carbon dioxide for EOR appear to have a similar effect on the price of FT diesel fuel for all of the Reference Plants. With IRR held at 19 percent, a 33 percent decline in the price of carbon dioxide for EOR and a tax credit of $11.30 per ton of sequestered carbon dioxide decrease FT fuel price by approximately 10 percent from the base case price. A 33 percent increase in the price of carbon dioxide causes a similar decrease in FT fuel price of 18 and 19 percent, respectively, for the Reference Plants that use bituminous coal and lignite, while the plant that uses sub-bituminous coal experiences an even greater decrease of 21 percent. Regardless of fuel type, however, it appears that fluctuations in carbon dioxide prices for EOR have a considerable effect on resultant FT fuel prices.

Notably, in each of the three cases the price of FT fuel is lower than in the base case for EOR: Additional revenue from the sale of carbon dioxide for EOR appears to combine with the tax credit for carbon dioxide sequestered to provide a significant incentive for plant developers to monetize the benefits of EOR by investing in and conducting sequestration operations.

3. Increase/Decrease in the Duration of Sequestration Tax Credits

This sensitivity test examined changes in the duration that a tax credit for carbon sequestered would be available to co-production investors. The analysis tests the impact of the time period that tax credits are available while holding constant the respective base case prices for FT fuel and capture rates for carbon dioxide produced in a plant. The analysis involves manipulating the tax credit per ton of carbon dioxide sequestered such that the base case fuel price achieves a 19 percent IRR. Scully Capital also estimated the budgetary impact and total costs associated with tax credits of different durations. Exhibit 7.26 displays the results of the analysis.

Exhibit 7.26: Sensitivity Test of the Time Horizon for Sequestration Tax Credits

	Duration of Tax Credit: 5 Years	Duration of Tax Credit: 10 Years	Duration of Tax Credit: 15 Years
Bituminous Reference Plant: FT Fuel Price = $72.83/ton (CEP = $56.02/ton)			
Sequestration Tax Credit ($/ton)	$16.20	$10.90	$9.57
Budgetary Impact ($ millions)	$472	$672	$590
Total Cost ($ millions)	$472	$672	$902
Sub-bituminous Reference Plant: FT Fuel Price = $59.00/ton (CEP = $45.38/ton)			
Sequestration Tax Credit ($/ton)	$16.85	$11.30	$9.95
Budgetary Impact ($ millions)	$453	$643	$566
Total Cost ($ millions)	$453	$643	$866
Lignite Reference Plant: FT Fuel Price = $76.00/ton (CEP = $58.46/ton)			
Sequestration Tax Credit ($/ton)	$15.83	$10.63	$9.36
Budgetary Impact ($ millions)	$487	$694	$611
Total Cost ($ millions)	$487	$694	$934

It appears that total cost and budgetary impact would be the lowest with the implementation of a higher tax credit for a shorter duration, as reflected in the results for the 5-year tax credit. However, it is questionable whether a tax credit available for a shorter time would promote sequestration after it terminates at the end of year five. Tax credits of a longer duration would continue to encourage investors to sequester, even in the absence of regulations requiring sequestration.

Notably, the budgetary impact expressed in nominal costs for the 15-year tax credit would be less than the impact for the 10-year tax credit because the last five years of the 15-year tax credit fall outside the budget window. Therefore, not only would this option provide a less expensive alternative to the 10-year credit in budgetary terms, but it would also provide a continuing impetus for plant owners to continue sequestering carbon dioxide.

VI. SUMMARY AND CONCLUSIONS

This chapter identifies a tax credit per ton of carbon dioxide sequestered as the best project-level incentive from a range of options for carbon dioxide sequestration at co-production plants under current tax and regulatory frameworks. The results of the analysis identify a breakeven point for the sequestration of carbon dioxide from these plants by showing the impact of this incentive on the economics and financial feasibility of three co-production Reference Plants with sequestration. A parallel analysis for Alternative Plants makes the same showing.

The chapter also examines the applicability of the incentive in light of significant project risks. The volatility of oil and gas prices is a major impediment to the construction and operation of early commercial co-production plants, along with uncertainties associated with many types of first-of-a-kind, capital-intensive projects. The sequestration of carbon dioxide from a co-production plant would further increase the cost of products from these plants and decrease their competitiveness. This overall decrease in competitiveness persists regardless of coal type and product mix (FT fuels versus electricity). A tax incentive based on the tons of carbon dioxide sequestered would help offset the cost impacts of sequestration, and it would create an ongoing bias to continue sequestration, if structured well. The analysis further shows the potential "upside" if the carbon dioxide were used for EOR.

Mandatory limits on carbon dioxide emissions would likely make the capture and sequestration of carbon dioxide an imperative for early commercial co-production facilities. While the current analysis does not incorporate such constraints, the results nonetheless inform a discussion of the means by which sequestration can be accelerated and/or encouraged. It does this by illuminating the relationships among key factors that impact the financial viability of these projects and by identifying, in the context of a set of transparent assumptions, the breakeven point for adding geological sequestration in the absence of a mandatory carbon dioxide limitation.

Exhibit 7.27 provides an overview of the key findings related to the cost of sequestration, the benefits of EOR with sequestration, and the tax credit level required to offset the costs of sequestration for all three Reference Plants. This exhibit shows that, without factoring in the effect of EOR on plant revenues or changes in the carbon dioxide capture rate of a plant, a tax credit of $10.63–$11.30 per ton would be needed for this purpose, depending on the type of coal used in a plant and not taking into account the potentially significant benefits and costs associated with a particular site. This analysis also shows that sequestration adversely affects a plant's competitiveness. It should be noted that Scully Capital was not asked to examine another significant variable: the rate at which a plant captures carbon dioxide. The conservative assumption used in the analysis (90 percent availability and 80 percent capture) reduces the total cost of the incentive by at least 20 percent compared to the cost using Mitretek's assumption of 95 percent capture.

Exhibit 7.27: Summary of Costs of Sequestration and Tax Credit Levels

Type of Co-Production Plant (price in $/barrel)	Reference Plant Using Bituminous Coal		Reference Plant Using Sub-bituminous Coal		Reference Plant Using Lignite	
	Price of FT Fuel	CEP	Price of FT Fuel	CEP	Price of FT Fuel	CEP
Base Case	$ 72.83	$ 56.02	$ 59.00	$ 45.38	$ 76.00	$ 58.46
with CC&C	76.88	59.14	63.04	48.49	80.16	61.66
with Sequestration	82.83	63.72	68.73	52.87	86.35	66.42
with EOR	$ 73.07	$ 56.21	$ 59.58	$ 45.83	$ 76.00	$ 58.46
Tax Credit to Offset Costs of Sequestration						
Tax Credit ($/ton)	$10.90 /ton		$11.30 /ton		$10.63 /ton	
Budgetary Impact ($ millions)	$672		$643		$694	
Total Cost ($ millions)	$672		$643		$694	

Exhibit 7.28 summarizes a comparison of sensitivity testing results for the Alternative Plant without sequestration and an Alternative Plant with sequestration. It shows that Alternative Plants display similar FT fuel price sensitivity to Reference Plants. The analysis also shows that the only factors that bring the price of FT fuels produced in an Alternative Plant with sequestration relatively close to those produced in an Alternative Plant without sequestration are electricity price and a plant's final availability. The electricity price finding shows that the increased net power configuration offers the Alternative Plant potential advantages over the Reference Plants if higher electricity prices can be assured over the long term, since higher prices for electricity reduce the FT fuel price to current market levels.

Exhibit 7.28: Sensitivity Testing for Alternative Plants without and with Carbon Sequestration

Summary of Analyses	Value Change	Alternative Plant			Alternative Plant with Sequestration		
		Value: + Price of FT Fuel (CEP) $/bbl	Value: - Price of FT Fuel (CEP) $/bbl	% Change in Price from Base Case	Value: + Price of FT Fuel (CEP) $/bbl	Value: - Price of FT Fuel (CEP) $/bbl	% Change in Price from Base Case
Base Case		**FT Diesel = $72.65, CEP = $55.85**			**FT Diesel = $83.47, CEP = $64.21**		
Debt Coverage	1.1x	$49 ($38)			$59 ($45)		
Electricity Price	+ 25%	$66 ($51)			$77 ($60)		
<u>Sensitivity Testing</u>							
EPC Costs	+/- 25%	$90 ($69)	$56 ($43)	+ / - 23.7%	$102 ($78)	$66 ($51)	+ / - 21.7%
Coal Cost	+/- 33%	$83 ($64)	$62 ($48)	+ / - 14.7%	$94 ($72)	$73 ($56)	+ / - 12.8%
Reduced Naphtha Output	15% of output	-	$69 ($53)	- 5.1%	-	$79 ($60)	- 5.9%
Interest Rates	+/- 25%	$78 ($60)	$68 ($52)	+7.3% / -6.6%	$89 ($68)	$78 ($60)	+6.6% / -6.0%
Final Availablity	+/- 5%	$68 ($52)	$79 ($61)	-6.6% / +9.2%	$79 ($60)	$90 ($70)	-5.9% / +8.3%
Construction Time	+1 Year/ -6 months	$81 ($62)	$69 ($53)	+10.9% / -5.2%	$92 ($71)	$80 ($61)	+9.9% / -4.7%
CO_2 Storage Costs	+/- 50%				$86 ($66)	$81 ($63)	- / + 2.6%

The primary conclusions of the analysis of the impact of carbon sequestration on the prospects for co-production facilities and of potential incentives to encourage or accelerate early commercial projects that sequester carbon dioxide produced in plant operations include:

Co-production plants that produce FT fuels are among the most promising opportunities for cost-effective early commercial sequestration of carbon dioxide

The capture of the carbon dioxide is inherent in the gasification and FT fuel production processes in co-production plants that manufacture FT fuels and electricity. The cost of sequestering process carbon dioxide is therefore limited in these co-production projects to the cost of compressing the carbon dioxide and transporting, storing, and monitoring it. Since the capture of carbon dioxide typically is the largest cost component of a sequestration system in large-scale plants that use coal, co-production projects that produce FT fuels have a "built-in" cost reduction for carbon dioxide sequestration. Thus, early commercial co-production plants offer coal-using industries a lower-risk and quicker opportunity to gain experience in mitigating technology, integration, and liability risks associated with commercial carbon dioxide sequestration than most other technologies and facilities.

The cost implications of sequestration make the unaided construction and operation of co-production plants with sequestration unlikely

The addition of sequestration to a co-production plant of any design evaluated may increase the cost of FT fuel by 14–16 percent from a base case price well above the floor price for crude oil applied by credit rating agencies to new energy projects. Given the projected price of FT fuel and the volatility of oil markets, this increase in the price of FT fuel to accommodate both sequestration and adequate financial returns is material; an increase of this magnitude to "breakeven" pricing represents a challenge in financing projects, even without sequestration.

A tax credit based on the amount of carbon dioxide sequestered may be the optimal incentive for encouraging sequestration

A tax credit based on the amount of carbon dioxide sequestered is potentially unique in that it can be structured to actively encourage sequestration operations associated with co-production projects; it also complements incentives that encourage the construction and operation of early commercial co-production plants. This tax credit encourages sequestration because a plant owner will earn no tax credit unless carbon dioxide is actually sequestered and because payment is based on tons sequestered.

In contrast, investment tax credits can be structured to create an incentive to *construct* facilities that have the capacity to sequester carbon, but since these tax credits accrue if such a facility has been constructed, they do not create an ongoing incentive to *operate* the sequestration facilities. Similarly, credit incentives can improve the prospects of obtaining financing for a facility capable of sequestering carbon and reduce the cost of borrowing, but they do not, as currently practiced, obligate the project to actually sequester carbon dioxide produced in the facility.[15]

The cost of sequestration can vary significantly

The cost of sequestration will depend on a number of site-specific factors, including the characteristics and operating performance of a co-production plant, the distance from the co-production plant to the injection well, and the geologic characteristics of the target formations (e.g., depth, thickness, permeability, storage capacity). In particular, the per ton cost of transporting and injecting the carbon dioxide is likely to vary on a site-by-site basis. The amount of carbon dioxide that would ultimately be sequestered depends significantly on plant design and operations.

Sequestration costs and requirements continue to be uncertain

Regulatory frameworks and protocols (e.g., risk management provisions) for the geologic sequestration of carbon dioxide, which have the potential to significantly alter the economics of carbon capture and sequestration projects, have not been fully developed at this time. Although substantial amounts of carbon dioxide are used in U.S. EOR operations, technical research into, and the large-scale demonstration of, long-term storage systems are ongoing. So, costs will become better understood only as large-scale geologic sequestration projects that are integrated with large anthropogenic sources of carbon dioxide progress. The “unknowns” associated with the integration of sequestration processes into the operations of coal-based plants, storage technologies, and regulatory ambiguity result in significant levels of uncertainty with respect to sequestration costs. Thus, project developers face numerous hurdles and uncertainties that affect the prospects for early commercial sequestration projects associated with large-scale coal-based projects.

Regulatory and liability issues surrounding carbon dioxide pipelines remain unclear

Although a number of carbon dioxide pipelines are operating without incident today, the advent of widespread sequestration will increase the potential for intensified regulatory oversight. The potential for litigation in the event of unplanned releases of carbon dioxide intended for sequestration and the uncertain availability of appropriately priced insurance for new carbon dioxide pipelines are likely to be challenges, especially in more heavily populated areas. Moreover, the siting of carbon dioxide pipelines is likely to remain an issue, especially in densely populated urban areas.

[15] It may be possible, however, to structure a credit enhancement so that the project sponsor could be required to sequester carbon dioxide as a condition of the execution of the instrument. In this case, though, the project sponsor could potentially refinance the project at a later point and no longer be subject to the original conditions of the credit enhancement.

The effectiveness of a sequestration-based incentive will depend foremost on the cost of sequestration

Since the cost to sequester carbon dioxide can vary significantly, a static tax incentive may or may not cover the entire cost of sequestration at a particular site and, therefore, may or may not be adequate to stimulate sequestration in the absence of regulatory drivers. Absent a regulatory requirement to sequester carbon dioxide, projects that can, at a minimum, recover the cost of sequestration through an incentive (and, possibly, EOR revenues) will be more likely to sequester the carbon dioxide they produce.

Enhanced oil recovery (EOR) with sequestration presents an additional opportunity to stimulate early commercial projects that sequester anthropogenic carbon dioxide, but the pricing of carbon dioxide for use in EOR projects is uncertain

EOR projects that pay $12 per ton of carbon dioxide over the life of the project appear to be able to offset the costs of sequestration for all three types of Reference Plants and for the Alternative Plants (i.e., with increased net power at the expense of FT production), but industry sources indicate that the per ton price ranges significantly. Sensitivity analyses show that fluctuations in carbon dioxide prices for EOR would have a considerable effect on resultant FT fuel prices (i.e., on prices that must be obtained to achieve acceptable returns on plant investment). A sequestration-based tax incentive would improve co-production plant economics and increase the commercial prospects for co-production projects that produce FT fuel and sell captured carbon dioxide for use in EOR projects, but uncertainty about the level of the tax incentive that would be effective is exacerbated by uncertainty about the pricing of carbon dioxide for EOR.

A tax credit set at a minimum of $11 to $12 per ton of carbon dioxide sequestered could offset sequestration costs for co-production plants that produce FT fuels

Estimates based on this analysis suggest that a tax credit of $11–$12 per ton of carbon dioxide sequestered could offset the cost of carbon dioxide sequestration from all three types of Reference Plants and from Alternative Plants, assuming a lowest-common-denominator approach to setting the level of the tax credit. This estimate depends materially on plant design and operating performance, site selection, and cost assumptions to transport, store, and monitor the carbon dioxide.

An incentive designed to cover the costs of sequestration would not improve Reference Plant economics sufficiently to trigger carbon dioxide sequestration — or construction of the plants that produce the carbon dioxide

The analyses show that base case prices for FT fuels produced in Reference Plants appear to be competitive in current markets, but above long-term assumptions of credit agencies. Thus, the construction and operation of early commercial co-production projects is likely to depend on incentives for the project, independent of a sequestration incentive. So, an incentive that fully covers the costs of sequestration would still leave a Reference Plant project exposed to price volatility risk in oil markets, as well as to such other key project risks as high construction cost and technology integration risk. To be commercially attractive, therefore, a co-production plant would most likely require incentives in addition to the incentive for sequestration. (As noted in Chapter 4, the combination of an increased power output and a long-term purchase agreement for power can enhance the credit quality of an Alternative Plant, at least to a significant degree, reducing the cost of providing incentives to build and operate the plant.)

An incentive designed to cover the costs of sequestration also is not sufficient to make Alternative Plants economically viable

The analysis also shows that Alternative Plants *with sequestration* that benefit from a sequestration tax credit cannot compete effectively in the absence of government incentives and/or mandates for construction and operation of the plant. Results of this analysis indicate that even an increase to $70 per MWh in the price at which such the plant could sell electricity — at the upper bound of current market prices for new base load electricity generation, results in an FT diesel fuel priced at $77 (CEP: $59) per barrel. Although this price is competitive in today's markets, the plant's FT fuel price exceeds that of the Reference Plant price by approximately $4 per barrel and is substantially above the long-term price assumed by credit agencies. So, the addition of an incentive to sequester carbon is insufficient to trigger early commercial plants of this type.

Power from an Alternative Plant that sequesters carbon dioxide at the levels evaluated in this analysis may comply with regulatory requirements for low-GHG power in some states

The analysis determined that carbon dioxide emissions levels per unit of electricity produced by the Alternative Plant with sequestration, on a per MWh basis, amount to 630 lbs/MWh. This finding reveals that this plant may be able to export electricity to states that have adopted regulations limiting carbon dioxide production levels. For example, results of the analysis show that the Alternative Plant with sequestration could comply with California's recent Greenhouse Gas Emissions Performance Standard Act, which requires that electricity may only be sold in California if the emissions resulting from its production do not exceed 1,100 lbs of carbon dioxide per unit of electricity. Moreover, as noted above, since the capture of carbon dioxide is inherent in normal plant operations, a co-production plant may be able to more inexpensively sequester carbon dioxide than other coal-based facilities, which have extra costs for carbon dioxide capture.

Sensitivity testing shows that carbon dioxide storage costs and the price of carbon dioxide for EOR can materially impact plant economics

Revenue from EOR opportunities can substantially offset the cost to sequester, a technology-dependent and site-specific amount which depends on the carbon dioxide capture rate and the cost to capture carbon dioxide and compress, transport, store, and monitor it. Sensitivity testing reveals that the economics of sequestration are most sensitive to sequestration costs and EOR opportunities. It is important to note that the price of carbon dioxide for EOR estimated in this study is based on limited data; it may change substantially as the market develops.

In the absence of sequestration mandates, a plant's investors may be unlikely to sequester carbon dioxide after the expiration of a tax credit for sequestration

The costs of sequestration appear to drive the cost of a plant's products upward to the point that, without a policy driver for sequestration, plant owners may be likely to discontinue sequestration after the expiration of the sequestration tax credit. The analysis suggests that, without a mandate to continue sequestration or a sufficient level of taxes on carbon dioxide emissions, plant investors may decide to terminate carbon dioxide sequestration once the tax credit has expired because the cost of sequestration will, in most situations, place their plant at a competitive disadvantage.

A tax credit for tons of carbon sequestered that spreads the financial incentive over a longer time may sustain sequestration activity longer

The analysis results show that a tax credit with a longer term could be structured to ensure that, absent a regulatory driver for carbon sequestration, plant owners will have an ongoing incentive to sequester carbon dioxide. Sustaining sequestration could lead to greater benefits from an environmental, market, and budget perspective. Moreover, sensitivity testing shows that a lower sequestration tax credit over a longer period of time has the same effect on the economics of a plant but a lower budgetary impact to the government.

The nature of a carbon sequestration incentive will affect the legal and financial structure of co-production projects

Because the cost of carbon dioxide sequestration is significant relative to the cost and revenue structure for building and operating co-production projects, the nature of a sequestration incentive will have a major impact on the legal and financial structures of these projects. Developers of co-production projects that sequester carbon dioxide, like developers of other capital-intensive projects, will structure their projects to reflect the tax effects of available incentives.

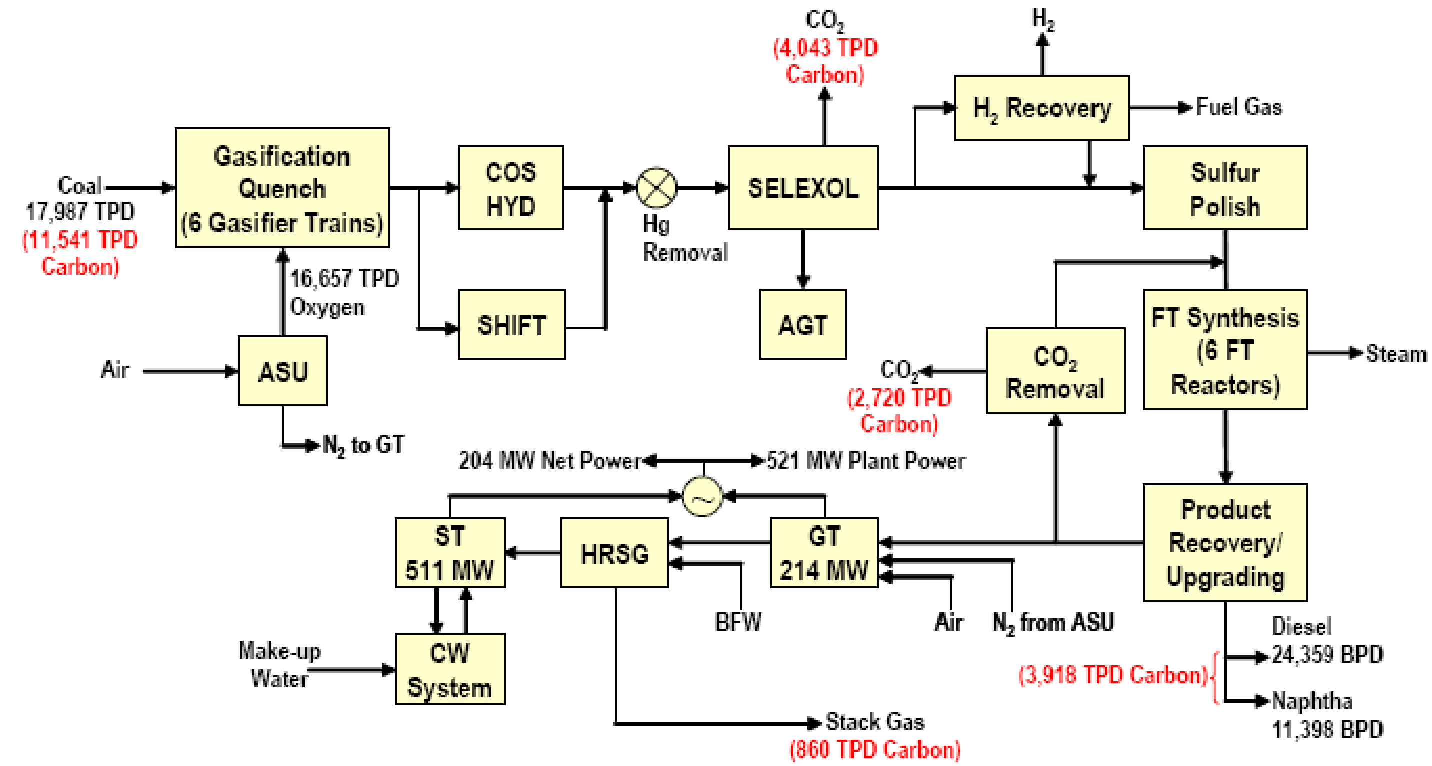
APPENDIX A: ABBREVIATIONS AND THEIR MEANINGS

Abbreviation	Meaning
AES Study	American Energy Security Study (AES Study)
bpd	Barrels Per Day
bps	Basis Points
BTU	British Thermal Unit
CC	Carbon Capture
CC&C	Carbon Capture and Compression
CCS	Carbon Capture and Storage
CEP	Crude-Equivalent Price
CTL	Coal-to-liquids
DoD	Department of Defense
DOE	Department of Energy
DSCR	Debt Service Coverage Ratio
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
EPC	Engineer, Procure, Construct
FT fuel	Fuel produced using the Fischer-Tropsch reaction
FT reaction	Fischer-Tropsch reaction
GTL	Gas-to-liquids
IGCC	Integrated Gasification Combined Cycle
ITC	Investment Tax Credit
IRR	Internal Rate of Return
MBtu	Million BTUs
MWe	Megawatts electrical
MWh	Megawatt hour
NETL	National Energy Technology Laboratory
OSD	Office of the Secretary of Defense
PA	Purchase Agreement
SAFETEA-LU	Safe, Accountable, Flexible, Effective Transportation Equity Act – a Legacy for Users
SSEB	Southern States Energy Board

APPENDIX B: PLANT SCHEMATICS AND CARBON BALANCES FOR REFERENCE PLANTS

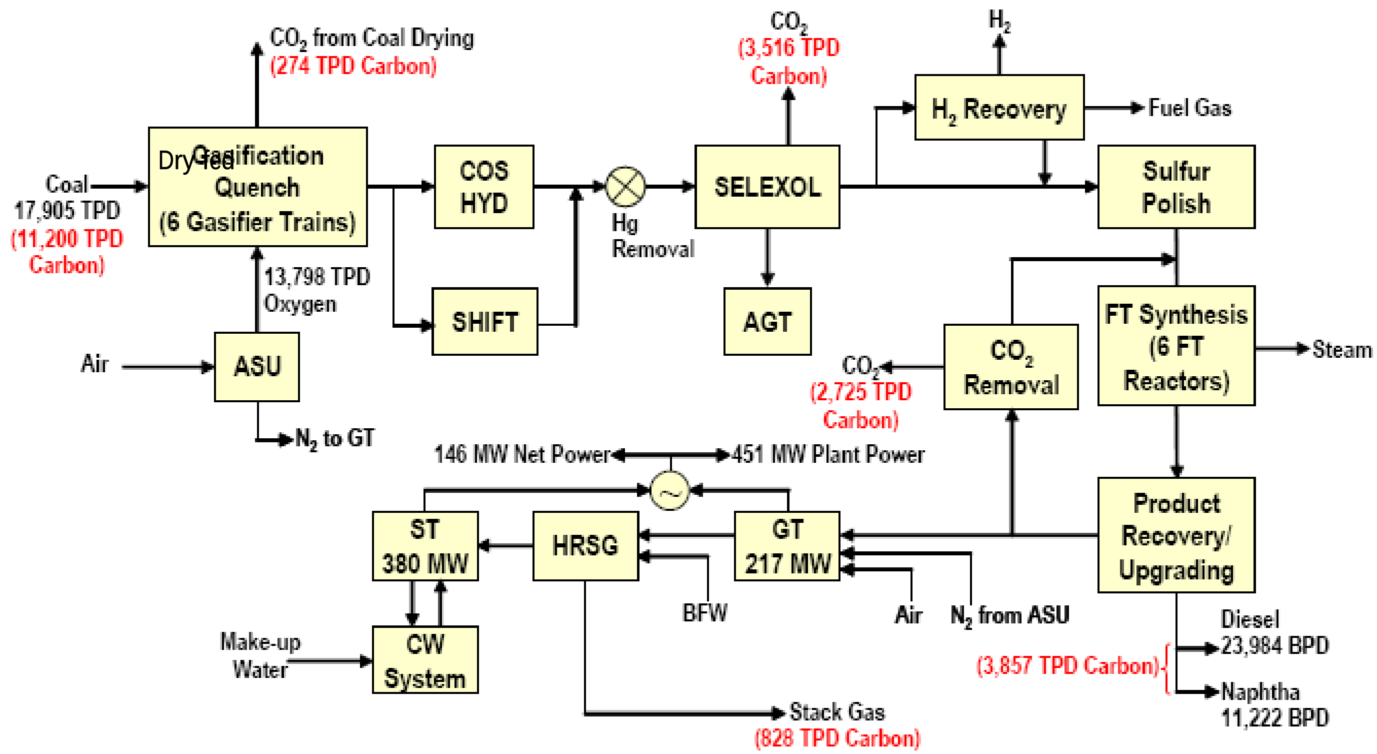
The following pages provide the plant schematics for three Reference Plants using bituminous and sub-bituminous coal and lignite, carbon balances for these plants, and calculations of the carbon dioxide that each plant can capture. The calculations assume that the plants operate with 90 percent availability.

Exhibit B-1: Plant Schematic and Captured Carbon Dioxide Calculation for Bituminous Reference Plant



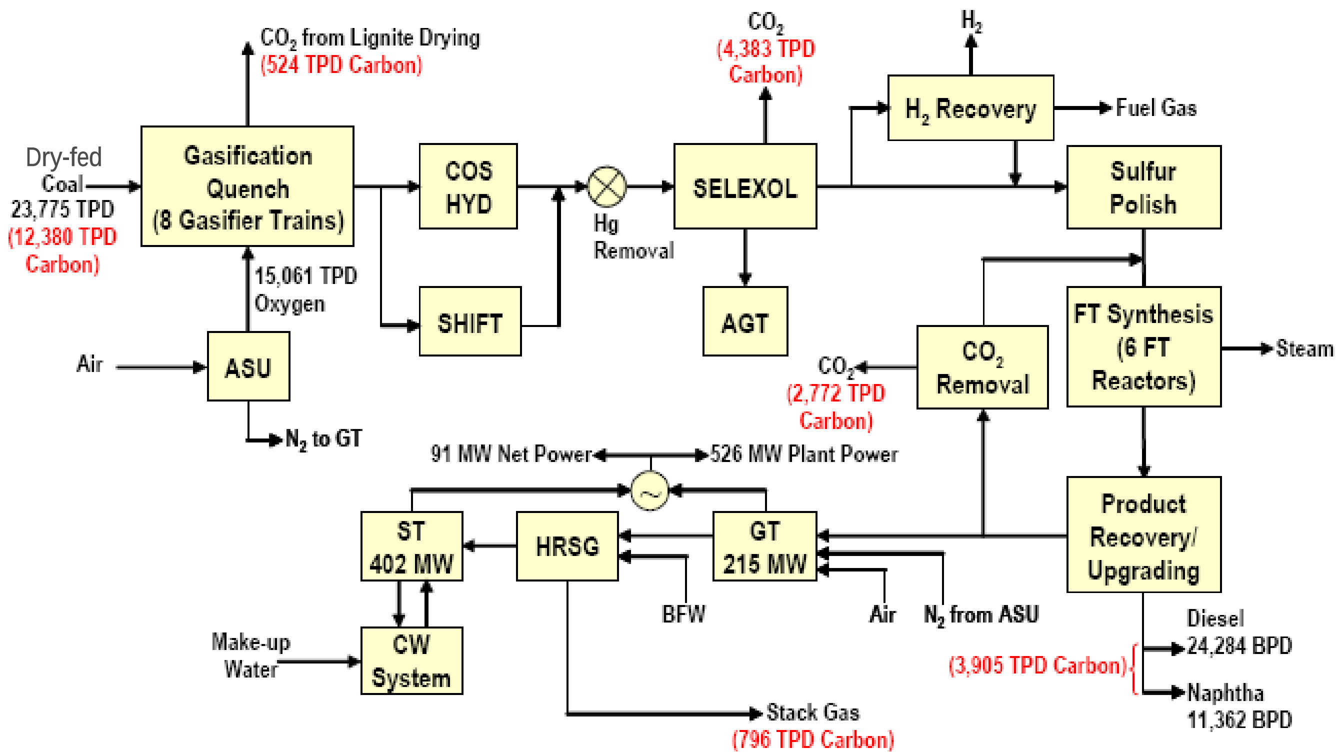
CO_2 Captured	Tons C	Tons CO_2
From Selexol	4,043	14,824
Post-FT	2,720	9,973
Total	6,763	24,798
Total @ 90% Utilization	6,087	22,318
Total @ 80% Capture	4,869	17,854

Exhibit B-2: Plant Schematic and Captured Carbon Dioxide Calculation for Sub-Bituminous Reference Plant



CO_2 Captured	Tons C	Tons CO_2
From Selexol	3,516	12,892
Post-FT	2,725	9,992
Total	6,241	22,884
Total @ 90% Utilization	5,617	20,595
Total @ 80% Capture	4,494	16,476

Exhibit B-3: Plant Schematic and Captured Carbon Dioxide Calculation for Lignite Reference Plant



CO_2 Captured	Tons C	Tons CO_2
From Selexol	4,383	16,071
Post-FT	2,772	10,164
Total	7,155	26,235
Total @ 90% Utilization	6,440	23,612
Total @ 80% Capture	5,152	18,889