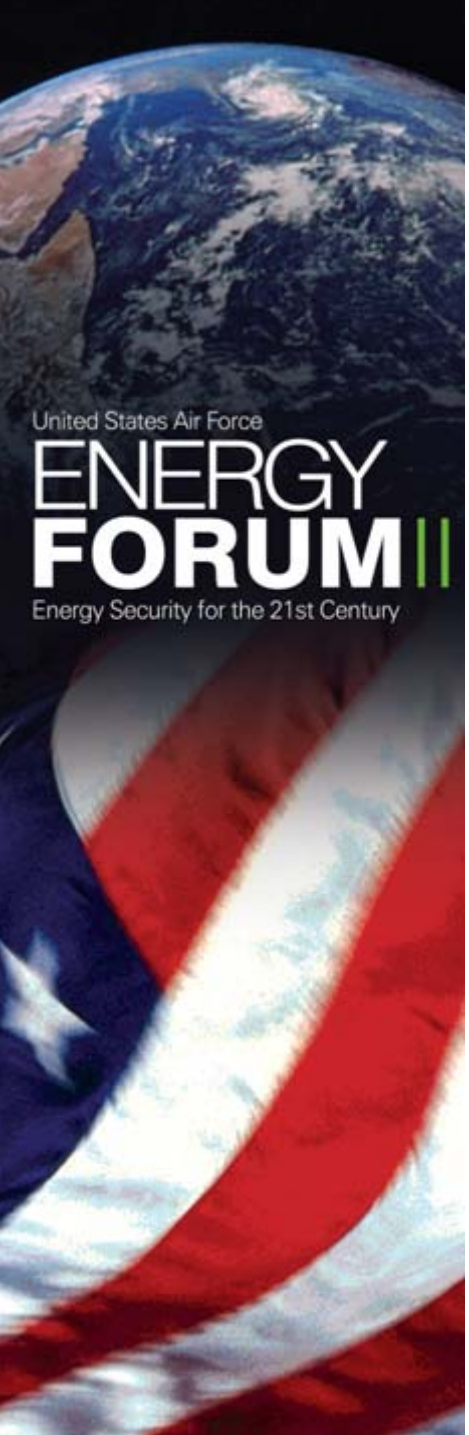


The Business Case for Coal Gasification with Co-Production

Business Risks
Financial Prospects
Potential Incentives
Impact of Sequestration

http://www.climatevision.gov/pdfs/Co-Production_Report.pdf

David R. Berg

Department of Energy

david.berg@hq.doe.gov
davidberg969@yahoo.com

March 4, 2008

Study Sponsors

Industry Co-Sponsors *

Integrated Project Team (IPT) led by DOE

SCULLY CAPITAL

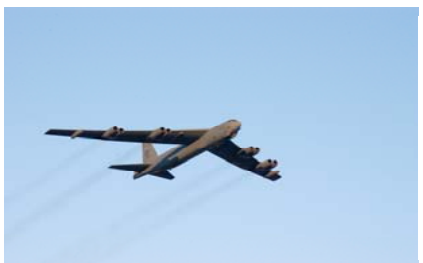
Technical Input
SSEB / Mitretek

*** Industry Co-Sponsors**

- **EPRI**
- **ACC**
- **TFI**
- **GTC**
- **AISI**

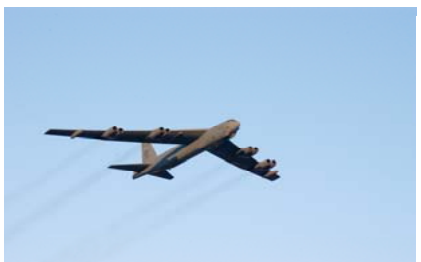
Project Elements

- “Reference Plants” for bituminous and sub-bituminous coal, plus lignite.
- Financial analyses and sensitivity testing for
  - Reference Plants and
  - An alternative configuration (2x power)
- Business risk assessment.
- Analysis of incentives.
- Analysis of the impact of carbon dioxide sequestration and of sequestration incentives.



REFERENCE PLANTS:

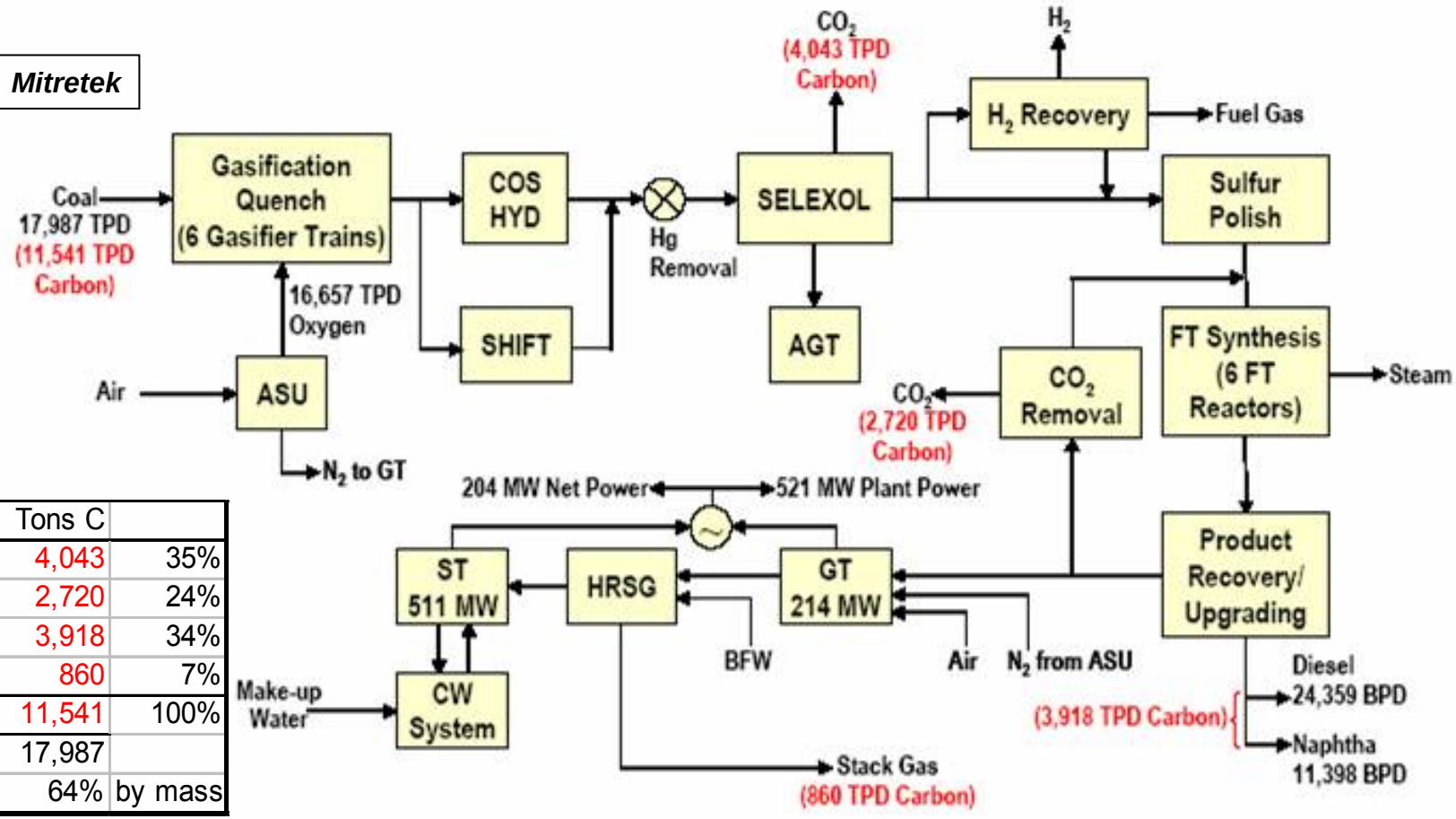
TECHNICAL AND FINANCIAL OVERVIEW



Technology / Plant Overview

- Plant schematic and carbon balance for 30,000 bpd, 725 MWe Reference Plant using bituminous coal.

Source: Mitretek



Mass balance	Tons 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

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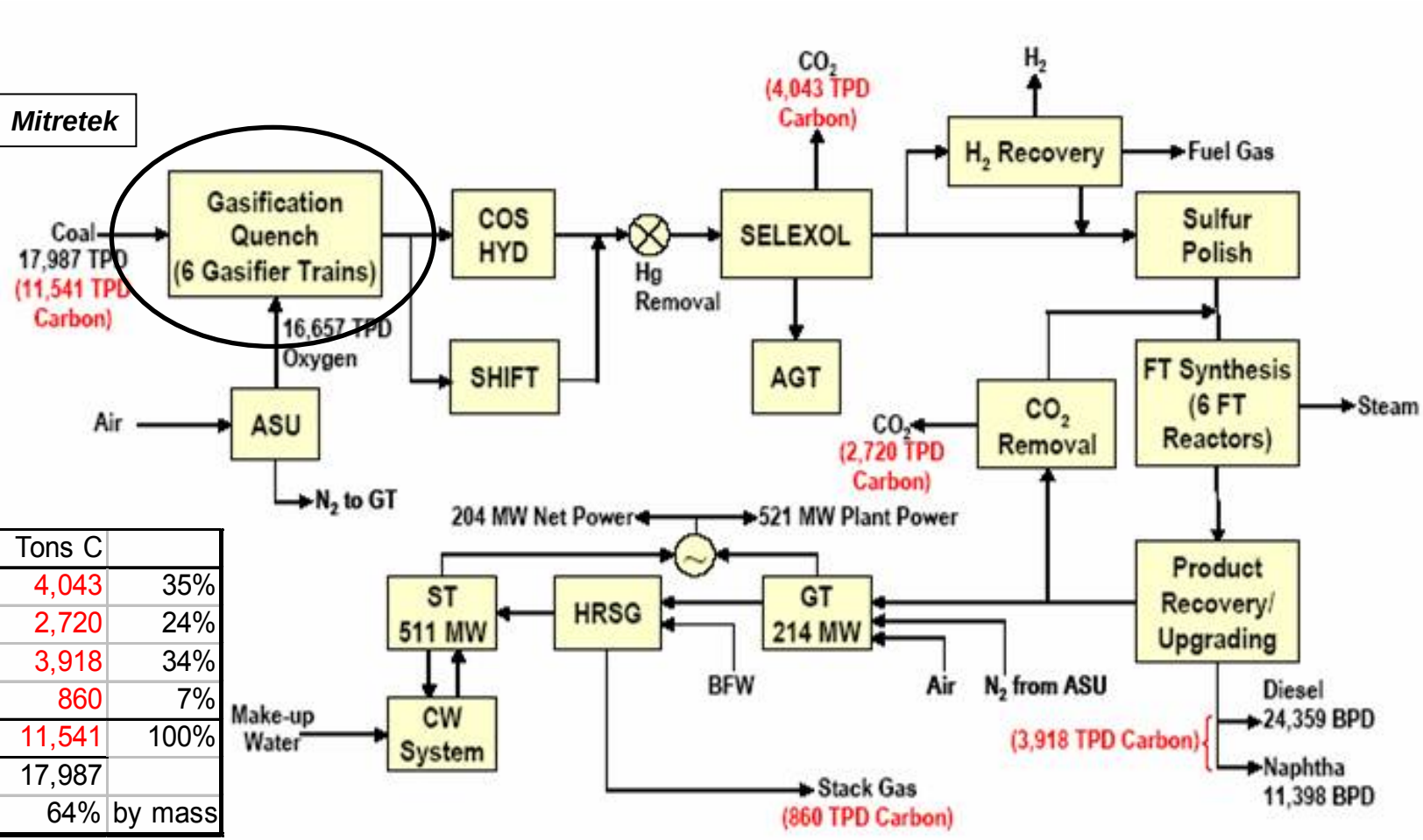

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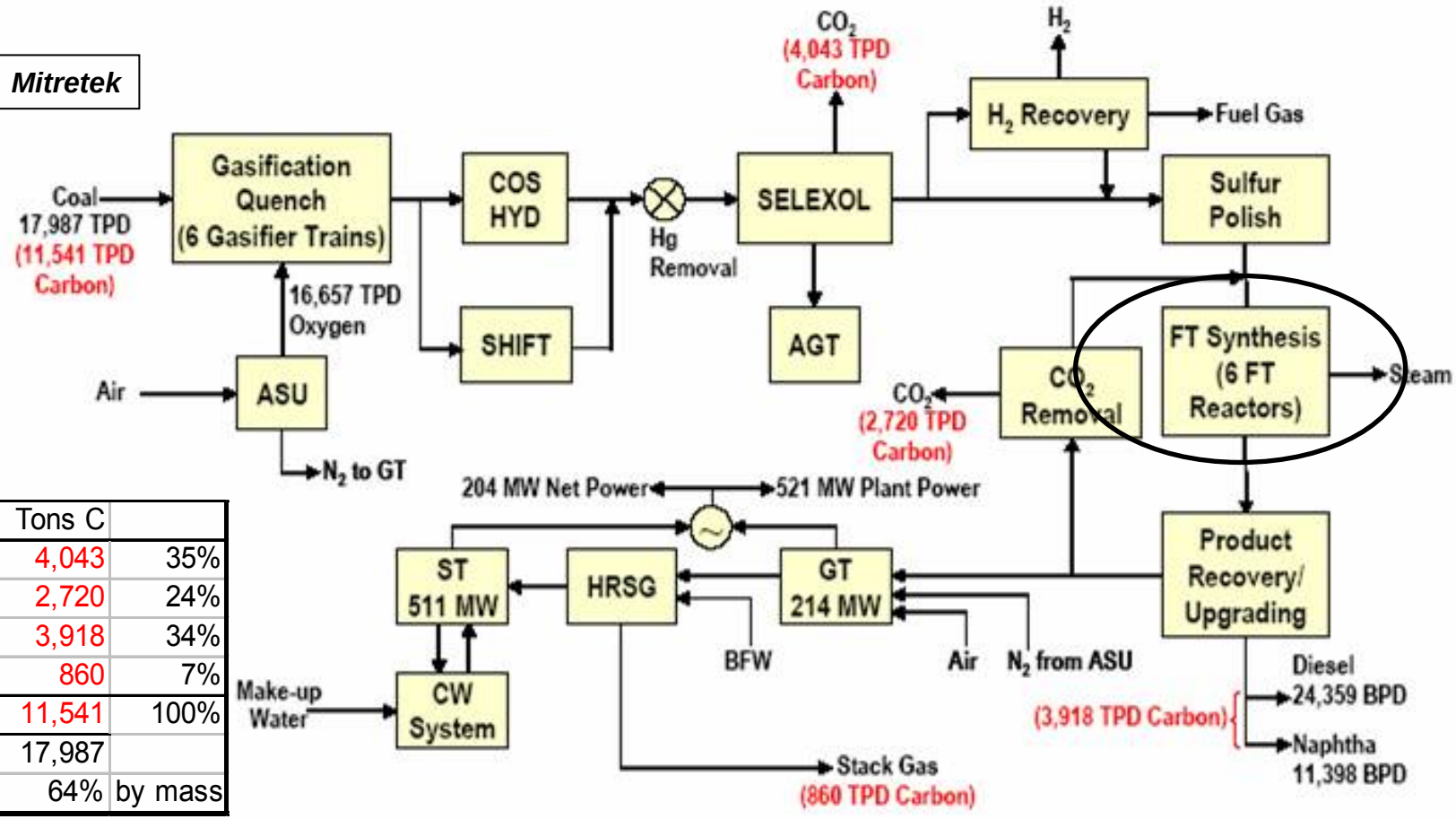

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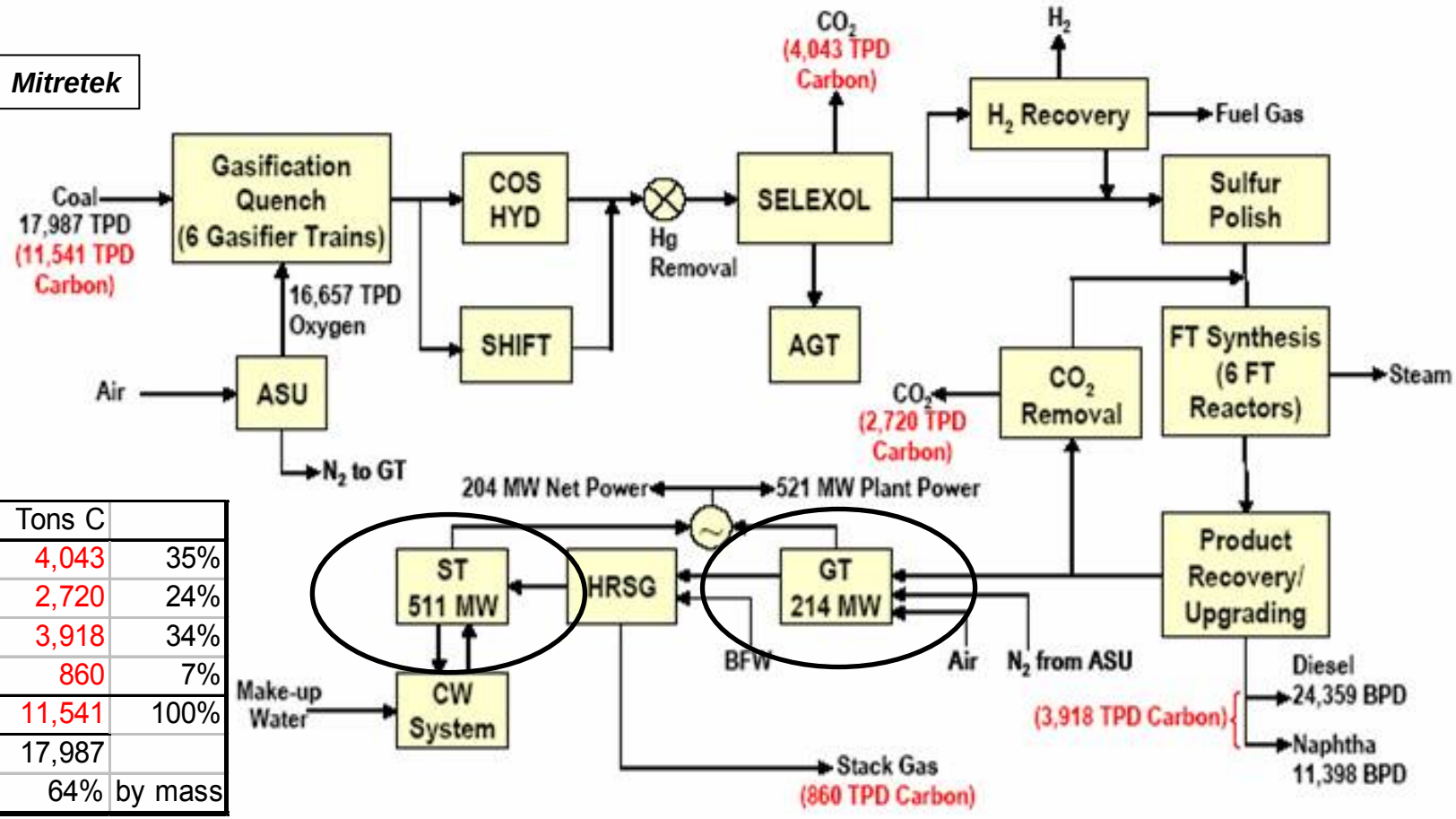

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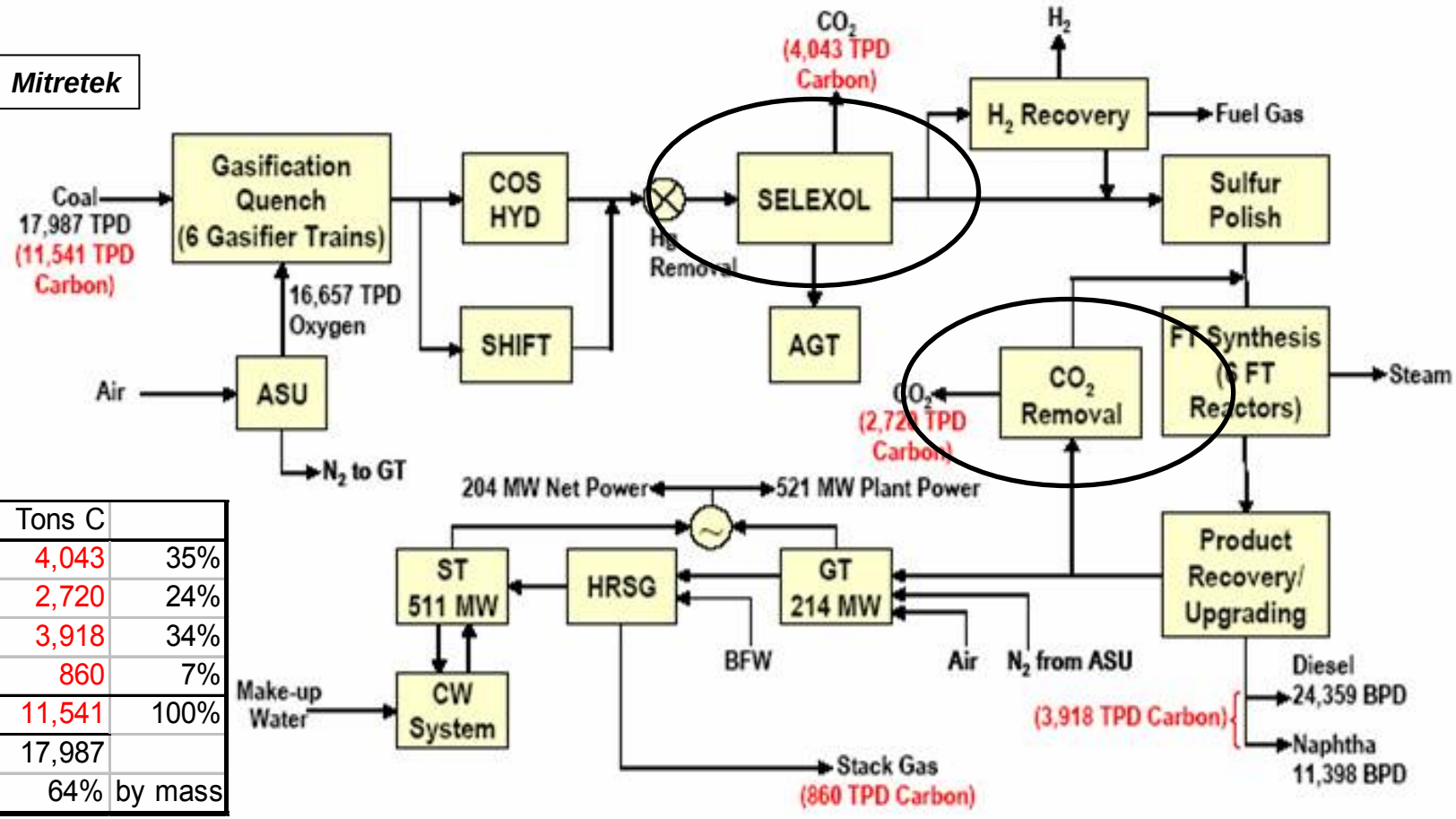

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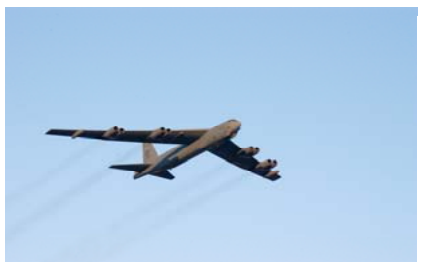
Reference Plant Costs, Outputs

Reference Plant (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 @ 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%

- Primary outputs: FT diesel and/or aviation fuel, naphtha, electricity (@ $58/MWh)
- ~32,500 bpd of diesel-equivalent fuel: 75% FT fuels; 35% naphtha (@ $30/bbl)
- 725 MWe of electricity, most used internally
- Parasitic load to compress CO_2: ~52 MWe
- Overnight capital cost: $2.6 B
- Total plant cost (2005 $): $3.2–3.6 B, +/- 30%
- Annual operating cost: $0.4 B

HIGHLIGHTS OF FINDINGS



Highlights of Findings

- **FT fuel from coal could be a competitive, assured source of transportation fuels, *but industry requires purchase agreements + (for some early plants) incentives.***
- A mid-size plant requires investment in the range of $3.3–$3.7 billion (in 2005 $ and +/- 30%) — depending on type of coal and the use of carbon handling equipment.
- Crude-equivalent price for bituminous coal-based FT fuels *without* carbon compression is $52–$56/bbl ($68–$73 for FT fuels). Carbon compression adds ~$4 (5%–6%).
- Sequestration adds 3%–5% ($130 mm) to capital cost — ~$6 (9%) to fuel cost.
- Carbon compression and sequestration (CCS) adds ~$10 to FT fuel price, but EOR revenues may offset CCS costs.

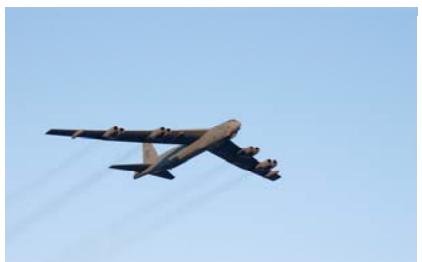
Highlights of Findings *(cont'd)*

- Very large scaling benefits over plant size range 10,000–30,000 bpd, then taper off.
- Alternative design (2x power) may enhance plant prospects.
- Use of sub-bituminous coal may enhance plant prospects.
- Key concerns among industry players: *Market risk*, *high capital cost*, *potential for cost overruns*, and *lack of construction / completion certainty*. Not excessive downtime.
- Skepticism exists about resolving national policy on CO_2. Long-term CCS liability must be addressed.
- ***Co-production plants that produce FT fuels are among the most promising opportunities for cost-effective early commercial CO_2 CCS.***

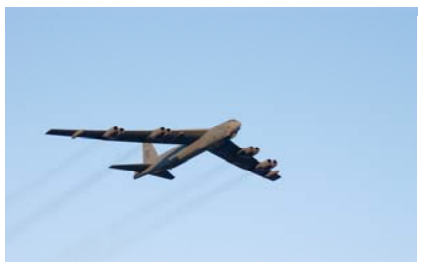
Highlights of Findings *(cont'd)*

- **Purchase agreement (PA)**: Flexible tool needed to address key project risks (e.g., *market*, inputs, performance). PAs pose budget challenges.
- **Tax incentives** (to address high capital cost) can reduce output pricing and may help with project creditworthiness. Budget cost varies directly with degree of financial "lift."
- **Loan guarantees** (to address high capital cost, cost overrun risk) can provide a big (14%–30%) reduction in FT fuel price, depending on their structure. Budget cost can be zero, depending on terms (i.e., if borrower pays credit premium).
- **Sequestration incentive:** Tax credit based on amount of carbon dioxide sequestered may be the optimal incentive.

BACK – UP SLIDES



REFERENCE PLANT SENSITIVITY TESTING RESULTS (BASED ON FINANCIAL MODELING OF PLANT USING BITUMINOUS COAL)



Sensitivity Testing: Key Results

Sensitivity Test	Value Change	Percentage Change in Price from Reference Case
Base Case: FT Diesel Value = $72.83, Crude Equivalent Price = $56.02		
EPC Cost	+/- 25%	+/- 18.7%
Coal Cost	+/- 33%	+/- 12.5%
Interest Rates	+/- 200 bps	+6.1% / -5.5%
Price of Electricity Sold	+/- 15%	-/+ 2.8%
Construction Time	+ 1year / - 6 months	+13.0% / -7.8%
Debt Amortization Period	+/- 5 years	-5.1% / 9.6%
Final Availability	+/- 5%	-5.4% / 7.6%
Reduced Naphtha Output	15% of output	-5.0%
Higher Naphtha Price	+ 100%	-19.3%
Capital Structure (Debt Percentage)	+/- 10%	-8.6% / 10.8%
Faster Ramp-up	75%, 85%, and 90%	-3.6%
Plant Size	10,000 bpd / 60,000 bpd	+37.2% / -5.2%
Use of CO_2 for EOR	$12/ton CO2	-4.2%

- Output of smaller plants will be more costly.
- Naphtha product pricing & coal input cost will significantly affect economics.
- Construction timeline and budget plus plant performance combined play a key role in final plant economics.
- Greater leverage in capital structure will reduce fuel price.

FT Fuel Price Sensitivity to CCS

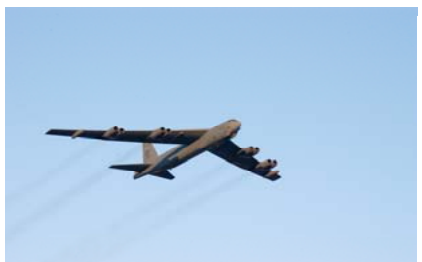
	Bituminous Reference Plant	Sub-bituminous Reference Plant	Lignite Reference Plant
Price of FT Fuel with Sequestion	$82.83 /bbl	$68.73 /bbl	$86.35 /bbl
Price of FT Fuel after Incentive	$72.83 /bbl	$59.00 /bbl	$76.00 /bbl
Incentive Value	$10.90 /ton	$11.30 /ton	$10.63 /ton
Budgetary Impact ($ millions)	$672	$643	$694
Total Cost ($ millions)	$672	$643	$694

- Price of FT fuel from Reference Plant: $68–73.
- Cost of sequestration adds significantly to FT fuel price.
- Sub-bituminous plant has significant cost advantages: lower priced coal (~$11 per ton vs. $36 per ton for bituminous coal) + lower capital cost.
- Early co-production plants are likely to be located near an EOR site — revenues from which will work like a long-term purchase agreement to further reduce FT fuel price.

Sensitivities for Alternative Plants

- FT fuel price sensitivity of Alternative Plants is similar to that of other co-production plants (i.e., is sensitive to construction cost, time, and cost overruns; plant availability; and design).
- They are also sensitive to coal price and naphtha production.
- Increased power output and a long-term PA for power combine to enhance the project's credit quality.
- Even with 2x power production, economic viability is very sensitive to sequestration cost (FT price: + $10/bbl)…
- but, a higher power price ($70/MWh) significantly reduces FT price and can reduce credit concerns, *and*
- this power may comply with regulatory requirements for low-GHG power in some states (e.g., CA).
- FT price is *not* sensitive to changes in cost of sequestration.

RESULTS OF ANALYSIS OF INCENTIVES (BASED ON FINANCIAL MODELING)



Incentives Analyzed

- Incentives analyzed separately and in (limited) combinations:
  - **Purchase (off-take) agreements (PA)**;
  - **Tax incentives** (accelerated depreciation / expensing, investment tax credits, excise tax credits, & tax exempt bonds);
  - Credit incentives in the form of **loan guarantees**;
  - **Grants**; and
  - **Combination case**.
- Some potential incentives were also analyzed as part of sensitivity testing, e.g., reduced coal cost.
- States may be able to provide some of the same incentives as the Federal government, e.g.:
  - Investment tax credits, grants;
  - Small project development grants of $5 million; and
  - Improved permitting or other regulatory processes (which do not have an explicit monetary value).

Long-Term Purchase Agreements

- **Definition:** Off-taker agrees to purchase a portion of plant output under pre-defined terms, which may involve:
  - Capacity payments
  - Fuel price adjustments / cost pass through
  - *Force majeure* "outs"
  - Price floors / ceilings
  - Liquidated damage / cure rights
  - Fixed start dates
  - Offer value for carbon capture
- Purchase Agreements (PAs) more flexibly address project risks than other incentives, but budget scoring is "front loaded": 5-year PA for a plant's entire output = ~$10 billion.
- PAs complement other incentives very well. A strong PA can assure a project's revenue stream, for example, reducing the credit subsidy cost of a loan guarantee.
- PAs can make financing *possible*.

Results: Tax Incentives

Type of Tax Incentive	FT Diesel/ Crude Equivalent Price per Barrel	Percentage Change from Reference Case	Budget Impact ($ millions)	Total Cost ($ 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

- Cost of tax incentives tends to move directly with benefit, and money is fungible...
- Utilizing tax incentives to enhance creditworthiness may result in little to no impact on price – and may not target key first-plant risks.

Results: Credit Incentives

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

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

- Loan guarantees can price reduce significantly (14%–30%) compared with Reference Case results.
- Self-pay loan guarantees are somewhat less powerful, but they offer a zero-budget impact if government correctly assesses risk, making a basket of them revenue and budget neutral.
- ***Equal "lift" from self-pay loan guarantee costs government ~$800 million less than excise tax credit*** *(25¢/gal for 10 years).*

Results: Grants (Cost-Sharing)

- Provide direct funding to project.
- Are particularly well-suited for early development expenses (pre-financing), such as to help pay for FEED, which helps reduce risk by improving construction cost estimates.
- A $200 million grant results in a 6% – 7% decrease in FT fuel price, but it is scored in the year it is awarded.
- A $1.3 billion grant (50% of the facility's hard costs) results in a 32% – 36% decrease in FT fuel price depending on whether the grant is repaid.

Results: Combination Case

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

- Both Combination Cases include three incentives:
  - Loan guarantee (100% of project debt, self-pay)
  - 5-year, $0.50 excise tax credit (= $21 per barrel)
  - $20 million state grant (pre-financial close)
- Both Combination Cases reduce the crude-equivalent price to roughly the previous and current floor prices for petroleum ($33/bbl, $39/bbl), although…
- at a cost, respectively, of $781 million and $383 million to the Federal government – all for the excise tax credit.

Incentives for CCS

	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
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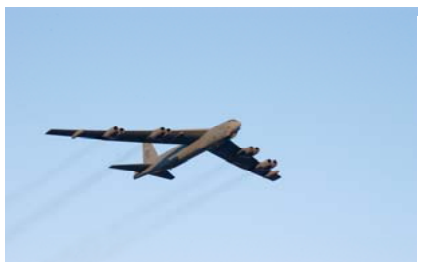
- A tax incentive worth ~$11.30 *per ton of CO_2 sequestered* can offset sequestration cost.
- Other incentives (e.g., ITC, loan guarantee) don't create an incentive to sequester (without a regulatory driver).
- Incentive should cover both cost and other risks.
- The first co-production plants are likely to be located near an EOR site, which at today's price for CO_2, will provide revenues of ~$12 per ton (range: $8 to $16).

INSIGHTS FROM INTERVIEWS WITH FINANCIAL COMMUNITY & INDUSTRY



Interviews Conducted

- **Banks / Financial Firms**
  - Credit Suisse
  - UBS
  - GE Capital
  - Hudson United
  - CIFG
  - New York Life
  - EEA Fund Management
  - Standard & Poor's
- **EPC Firms**
  - WorleyParsons
  - Fluor
- **Developers**
  - Baard Energy
  - Leucadia
  - Agrium
  - Excelsior
- **Technology Providers**
  - Shell
  - ConocoPhillips
  - Econo-Power International

Industry Interview Results

Industry interviews confirm sensitivity testing & "Q" results:

- **Purchase Agreement/Off-take Agreement:** A long-term, creditworthy off-taker was mentioned uniformly as a key requirement to offsetting price volatility in energy markets.
- **Volatility of Oil Markets:** Energy price volatility is seen as a key obstacle to financing CTL plants. Lenders mentioned the cost of FT diesel needed to service debt as a key benchmark in determining the ability of a project to withstand price volatility.
- **Length of Debt:** While lenders mentioned that, in certain project finance deals, the length of amortization can be longer than the purchase agreement, they doubt that it can be done for the first co-production plant.
- **Capital Cost:** In general, developers find plant cost estimates high, EPC contractors find the plant cost used low, and others find it to be approximately in the right range.

Industry Interview Results (cont'd)

Important observations include:

- **Technology Risk/Completion Risk:** Lenders & investment bankers uniformly mention the likely lack of EPC wraps with performance guarantees on CTL plants as a key obstacle to arranging financing for projects.
- **Internal Rate of Return (IRR):** Most interviewees express comfort with IRRs of 17% – 19%, after tax. Many specifically offer that the IRR requirement could increase unless the off-take agreement has sufficient length and quality. *The resulting cost of capital fits well with the WACC range for oil and gas companies.*
- **Project Finance Structure:** Some interviewees believe a project finance structure is possible, but cite as keys to completing non-recourse financings (a) the apparent lack of EPC wraps and (b) the need for a long-term, creditworthy off-taker. Others indicated that a limited recourse structure might be better for the first plants.

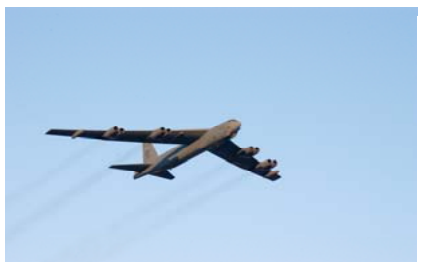
Highest Risks vs. Incentives

Different incentives address different critical risks. By considering both cost *and* applicability, cost-effectiveness can be enhanced.

Net Cost to Gov't	For Co-production plants Q# / Risk ratings made during Fall 2006 (20 interviews) / Risk rating value (25 pts)==>	Highest rated risks (descending order) ===> #1 High Cap Cost 16.0	#29 Short DOD P.Agmt 15.2	#8 Over budget on build 14.2	#30 Shaky off-take P.Agmt 13.9	#19 Lagging Nat'l incents 13.7	#6 Tight EPC capacty 13.1	#28 Finance difficult (terms) 12.4	#10 Thin EPC wrap 11.7	Overall Effective -ness
	INCENTIVE									
1	Self-pay loan guarantee	◆	◆	◇	◆	◆	◇	◇	◆	High
2	Loan guarantee (appropriated)	◆	◆	◇	◆	◆	◇	◆	◆	High
2	Tax-exempt debt (low interest)	◆	◇	◇	◇	◇	◇	◇	◇	Low
1	Accelerated depreciation	◆	◇	◇	◇	◇	◇	◇	◇	Low
3	Long purchase agreement	◆	◆	◇	◆	◆	◇	◆	◇	High
3	R&D and Tech demos	◆	◇	◇	◇	◇	◇	◇	◇	Med
3	Government grant (cost-share)	◆	◇	◇	◇	◇	◇	◇	◇	Low
3	Investment tax credit	◇	◇	◇	◇	◇	◇	◇	◇	Low
5	Excise tax credit or PTC	◆	◇	◇	◇	◆	◇	◆	◇	Med
	MANDATE									
2	Price guarantee (collar)	◇	◆	◇	◆	◆	◇	◆	◇	Med
2	Carbon cap & trade (mandate)	◇	◇	◇	◇	◆	◇	◇	◇	Low
high										
	Risk coverage by incentives	Max	Mid	Min	Mid	Max	Min	Max	Mid	

KEY	
◆	Highest or maximum effect
◇	Medium or midpoint value
◇	Little or no effect or value
	Zone of best value relative to net cost to gov't

RISK RATING RESULTS

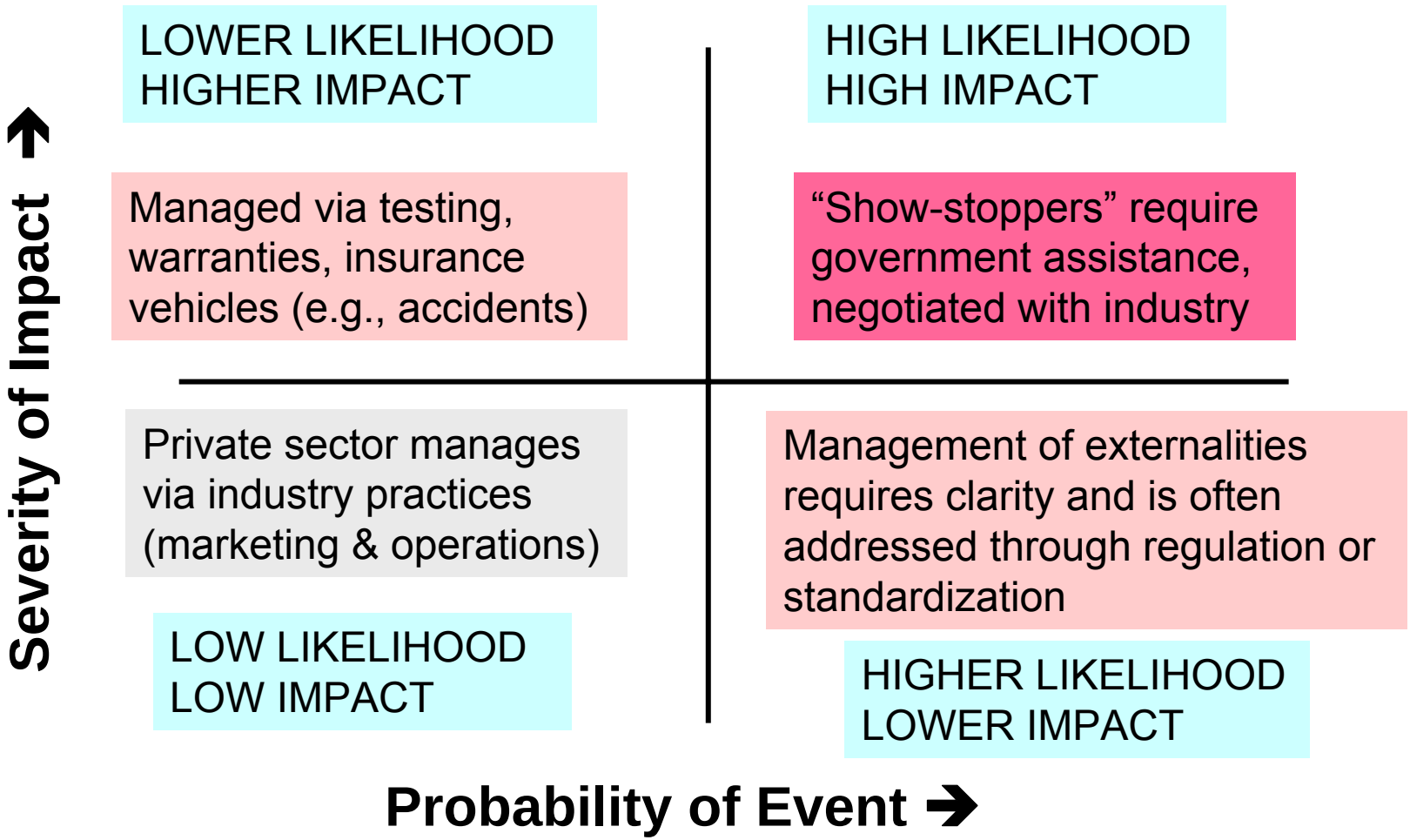


Questionnaire Responses (20)

- **Banks/Financial Firms**
  - Credit Suisse
  - Bank of America Securities
  - Standard & Poor's
- **Chemical / Fuel Manufs.**
  - Eastman Chemical
  - SASOL
  - Rentech
  - The Fertilizer Institute
- **EPC Firms**
  - Bechtel
  - Fluor / Hensley
  - Burns & McDonnell
- **Feds (DOD, DOE):**
  - Air Force, DOE/FE
- **Project Developers**
  - Leucadia
  - Tondu Corp.
  - E3 Gasification
  - Baard Energy
- **Technology Vendors**
  - ConocoPhillips
- **Utilities / IPPs**
  - EPRI
  - Excelsior Energy
- **States / NGOs:** Illinois

Risk Framework: Probability vs. Impact

Framework for plotting questionnaire results facilitates risk-informed government participation:



Risk Ratings: Overview

- Among 33 risks in 3 categories (technical, regulatory & policy, market), 3 *project* risks rate highest:
  - **High capital cost**
  - **Tightness in construction sector (in EPC capacity, warrantees)**
  - **Price increases in materials & equipment (risk of budget overrun)**
- Respondents also expressed a similarly high level of concern about two other important uncertainties:
  - **Availability of off-take agreements to help contain *market* risk**
  - **Availability of *incentives* to address project risks**
- Taken together, these key risks make financing problematic.
- Risk rating results conform with interview observations.
- Concerns also persist about lack of resolution about – and impact of – carbon policy.

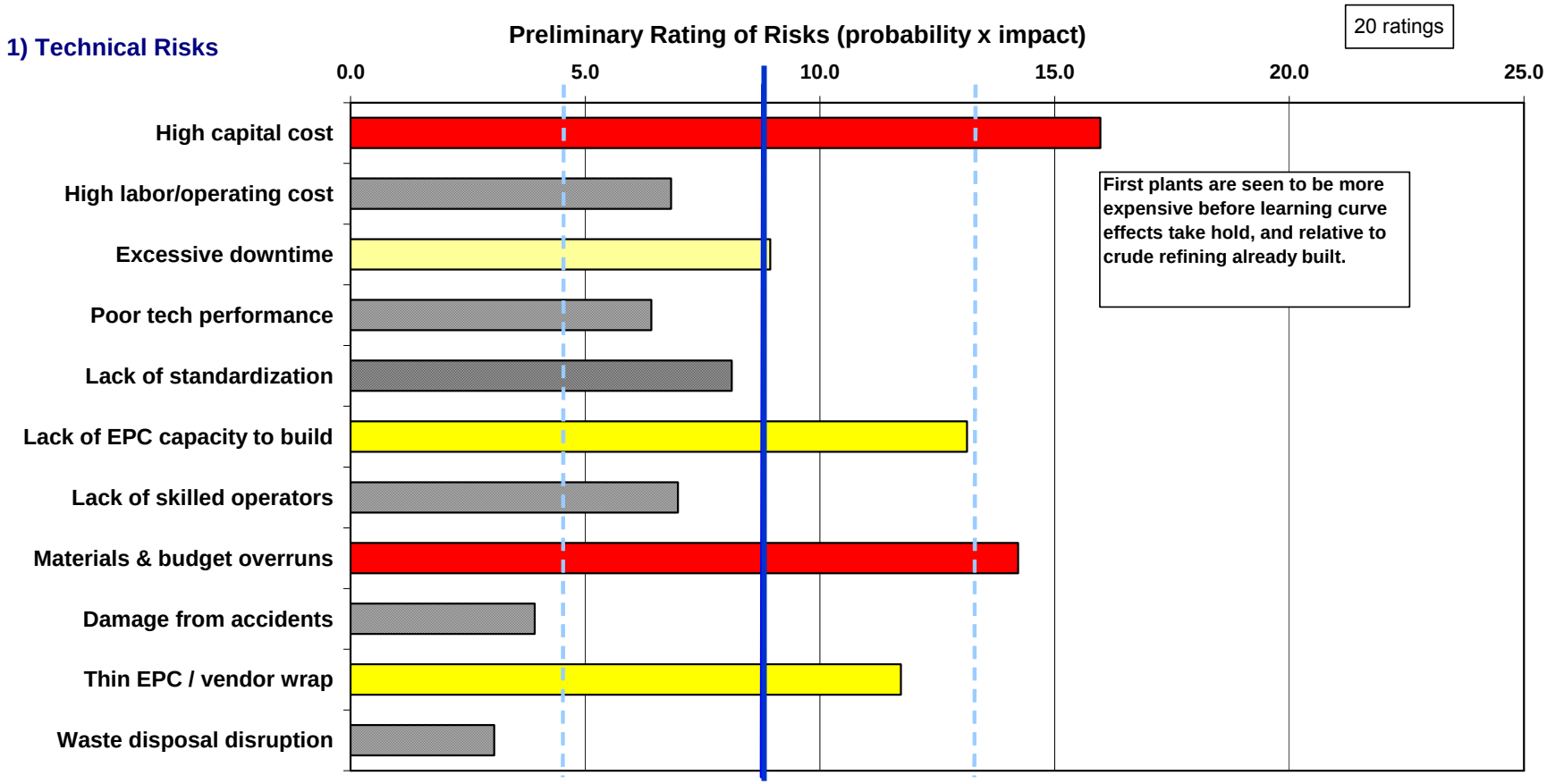
Summary: Highest Risk Ratings

	25 pt. scale (5 x 5 = 25)	Co-Prod'n	Co-Prod'n	20		50Rs
	Risk Area for IGCC	A	B	**2006**		**2005**
Q#	**Highest Risks**	**Probablty**	**Severity**	**Rating**		**IGCC**
1	High capital cost	3.6	4.5	**16.0**		**14.9**
3*	Excessive downtime	2.5	3.7	8.9		**13.1**
6	Lack of EPC capacity to build	3.6	3.7	**13.1**		6.5
8	Materials & budget overruns	3.6	4.0	**14.2**		10.9
10	Thin EPC / vendor wrap	3.4	3.5	**11.7**		9.5
12*	State air permitting delays	2.2	3.4	7.2		**13.0**
18*	Regional policy on sequest lag	3.0	2.7	7.8		11.4
19	Nat'l incentives on plants lag	3.3	4.2	**13.7**		11.8
28	Financing difficult (equity, terms	3.0	4.2	**12.4**		**13.0**
29	DOD purchase agreement thin	4.0	3.9	**15.2**		**NR**
30	Long-term off-take inadequate	3.4	4.1	**13.9**		**NR**
	Overall Average	**2.6**	**3.3**	**8.7**		**9.0**

- Concerns about high capital cost rate highest for co-production plants.
- Concerns about cost overruns and tight EPC capacity also are elevated.
- Uncertainties about off-take and incentives add to financing challenges.
- Combined, these risks explain why plants are not being built, unaided.

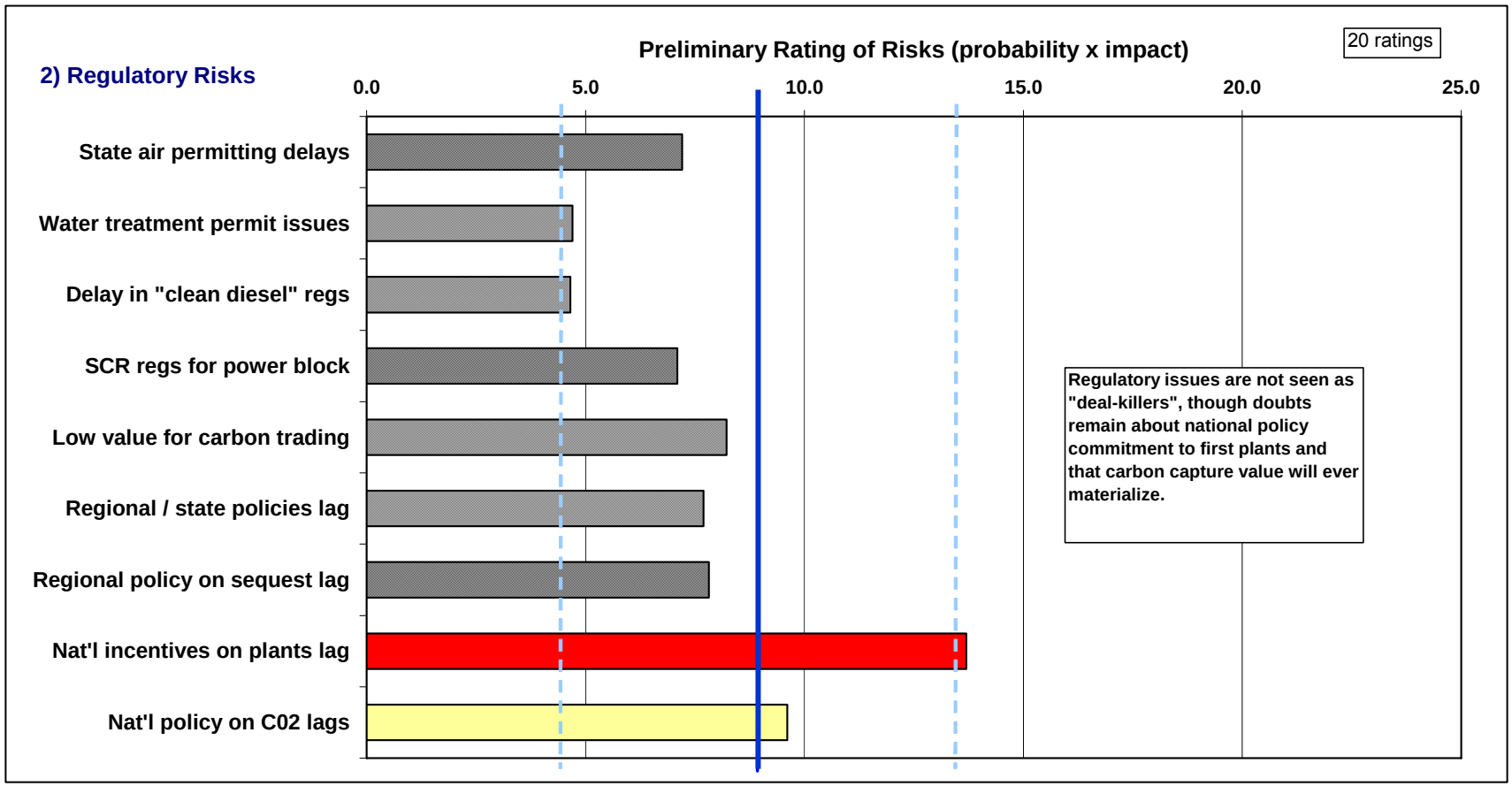
Risk Ratings: Technical

Respondents consider first plants to be more expensive (before learning curve effects take hold and relative to crude refineries). Today's tight EPC market has increased key ratings. Materials costs are also elevated.



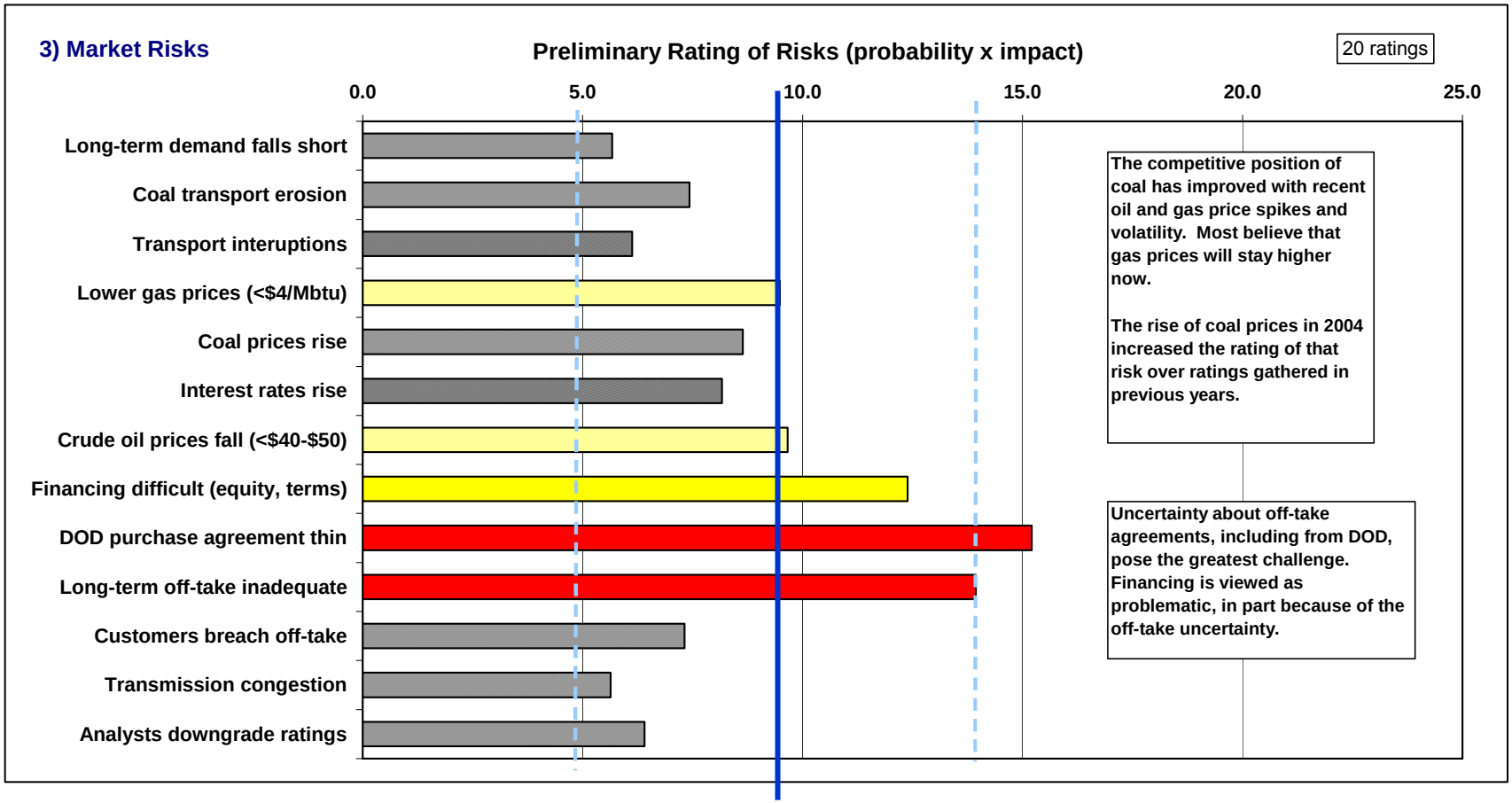
Risk Ratings: Policy & Regulatory

Respondents do not consider regulatory issues "deal-killers", but doubts remain about the Nation's policy commitment to first plants and about whether carbon capture value will materialize.



Risk Ratings: Market

Respondents' uncertainty with off-take agreements, including potentially from DOD, poses the greatest challenge among market risks. Financing, a derivative risk, is problematic, in part because of off-take uncertainty.



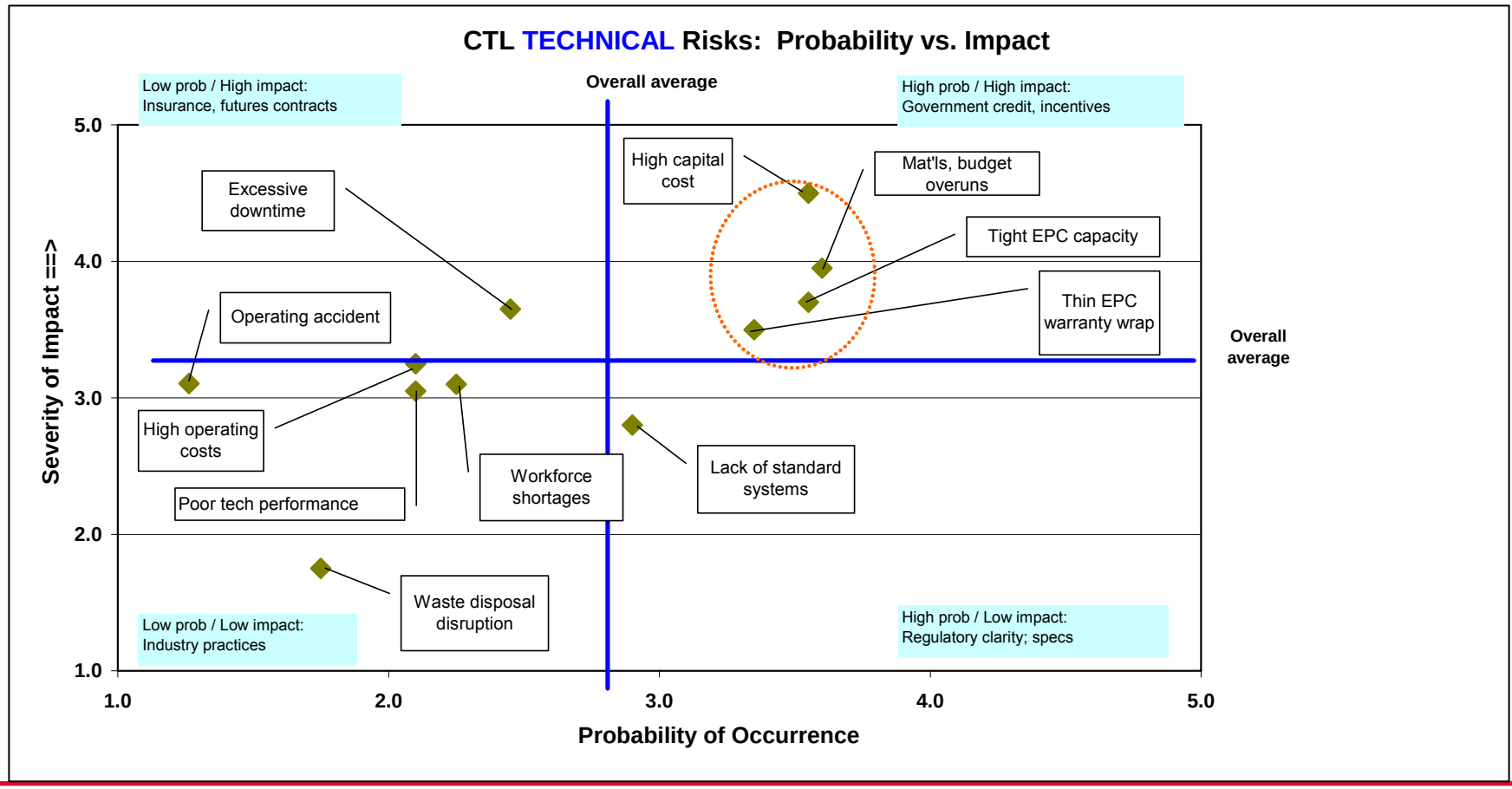
Risk Ratings: Technical

High ratings on capital costs match those for IGCC, but concerns about excessive downtime are muted, in part because chemicals or fuels can be stored (unlike electricity). In addition, chemical firms have more operating confidence. The "EPC wrap" is seen as more problematic in co-production.

	Risk Ratings for Co-Production	2006	2006	Co-Prod'n Total		IGCC 2005	IGCC 2004
				20		50Rs	33Rs
	Risk Area	A	B	A x B		A x B	A x B
	Technical	**Probablty**	**Severity**	**Rating**		**Rating**	**Rating**
1	High capital cost	3.6	4.5	**16.0**		**14.9**	**19.2**
2	High labor/operating cost	2.1	3.3	6.8		7.4	7.9
3	Excessive downtime	2.5	3.7	8.9		**13.1**	**15.2**
4	Poor tech performance	2.1	3.1	6.4		8.1	9.7
5	Lack of standardization	2.9	2.8	8.1		9.8	**12.3**
6	Lack of EPC capacity to build	3.6	3.7	**13.1**		6.5	6.1
7	Lack of skilled operators	2.3	3.1	7.0		7.3	7.2
8	Materials & budget overruns	3.6	4.0	**14.2**		10.9	10.4
9	Damage from accidents	1.3	3.1	3.9		5.7	5.2
10	Thin EPC / vendor wrap	3.4	3.5	11.7		9.5	6.8
11	Waste disposal disruption	1.8	1.8	3.1		4.4	3.7

Plot of Technical Risk Ratings

High capital costs, fear of budget overruns, tight EPC capacity, and lack of a real warranty wrap on CTL plants pose risks too great for the private sector to address without government support, particularly for "first mover" projects.



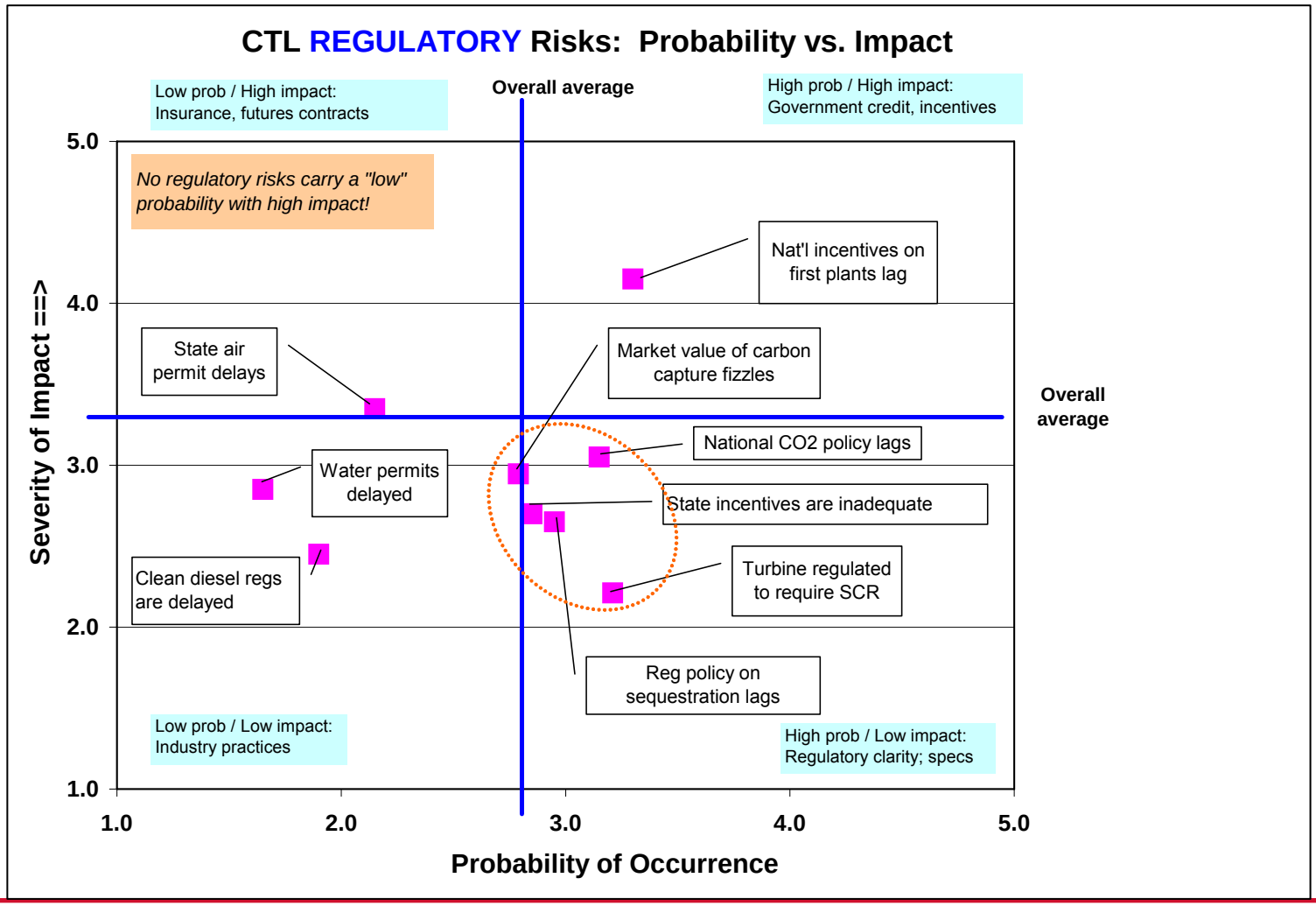
Risk Ratings: Policy & Regulatory

Respondents do not see regulatory issues as "deal-killers", but retain doubts about the Nation's policy commitment to first plants and about whether carbon capture value will materialize. Co-production investors and developers are not as concerned about CO_2 policy as power utilities. Competing fossil prices are a bigger issue for producers of FT fuels than regulatory issues because of market exposure.

	Risk Area Regulatory	Probablty	Impact	2006 Rating		2005 Rating	2004 Rating
12	State air permitting delays	2.2	3.4	7.2		13.0	10.9
13	Water treatment permit issues	1.7	2.9	4.7		8.2	7.4
14	Delay in "clean diesel" regs	1.9	2.5	4.7		7.6	9.0
15	SCR regs for power block	3.2	2.2	7.1		8.7	11.1
16	Low value for carbon trading	2.8	2.9	8.2		10.3	10.8
17	Regional / state policies lag	2.9	2.7	7.7		6.6	6.7
18	Regional policy on sequest lag	3.0	2.7	7.8		11.4	11.7
19	Nat'l incentives on plants lag	3.3	4.2	13.7		NR	NR
20	Nat'l policy on C02 lags	3.2	3.1	9.6		11.8	13.7

Plot of Policy & Regulatory Risks

Skepticism persists that national incentives on first plants will provide insufficient encouragement for early projects.



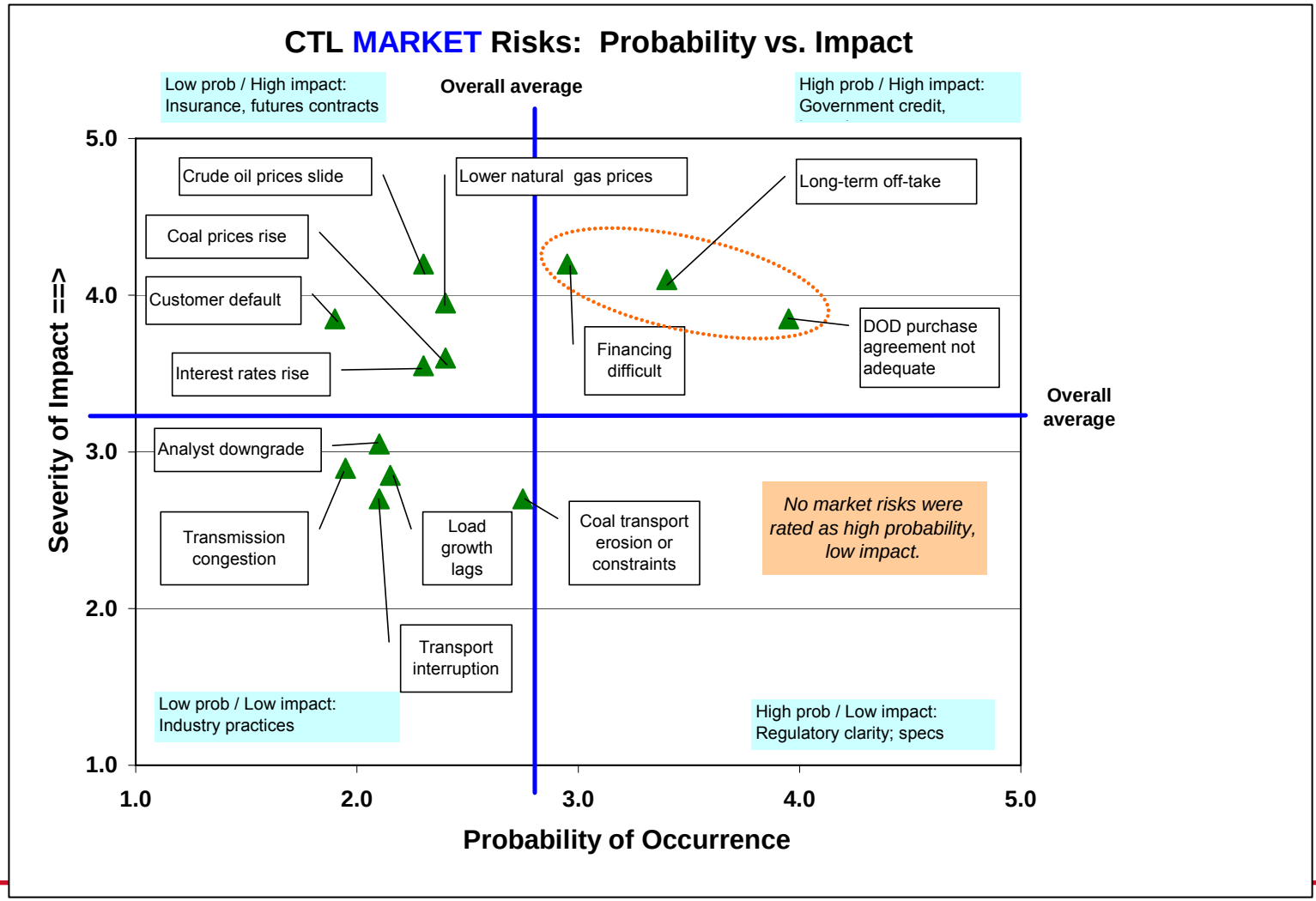
Risk Ratings: Market

Recent oil and gas price spikes and price volatility improve the competitive position of coal, but respondents reflect their concerns about this market risk by seeking off-take agreements. Most observers expect gas prices to stay higher. Risk ratings for coal price increased after price rises in 2004.

				Co-Prod'n		IGCC	IGCC
	Risk Area	2006	2006	2006		2005	2004
	Market	**Probablty**	**Severity**	**Rating**		**Rating**	**Rating**
21	Long-term demand falls short	2.1	2.7	5.7		8.0	7.7
22	Coal transport erosion	2.8	2.7	7.4		8.9	4.6
23	Transport interuptions	2.2	2.9	6.1		8.0	11.2
24	Lower gas prices (<$4/Mbtu)	2.4	4.0	9.5		7.2	7.0
25	Coal prices rise	2.4	3.6	8.6		7.9	6.3
26	Interest rates rise	2.3	3.6	8.2		10.2	11.7
27	Crude oil prices fall (<$40-$50)	2.3	4.2	9.7		11.2	**12.5**
28	Financing difficult (equity, terms	3.0	4.2	**12.4**		**13.0**	**16.1**
29	DOD purchase agreement thin	4.0	3.9	**15.2**		7.4	5.8
30	Long-term off-take inadequate	3.4	4.1	**13.9**		**NR**	7.6
31	Customers breach off-take	1.9	3.9	7.3		8.6	**NR**
32	Transmission congestion	1.9	2.9	5.6		6.8	**NR**
33	Analysts downgrade ratings	2.1	3.1	6.4		6.2	**NR**

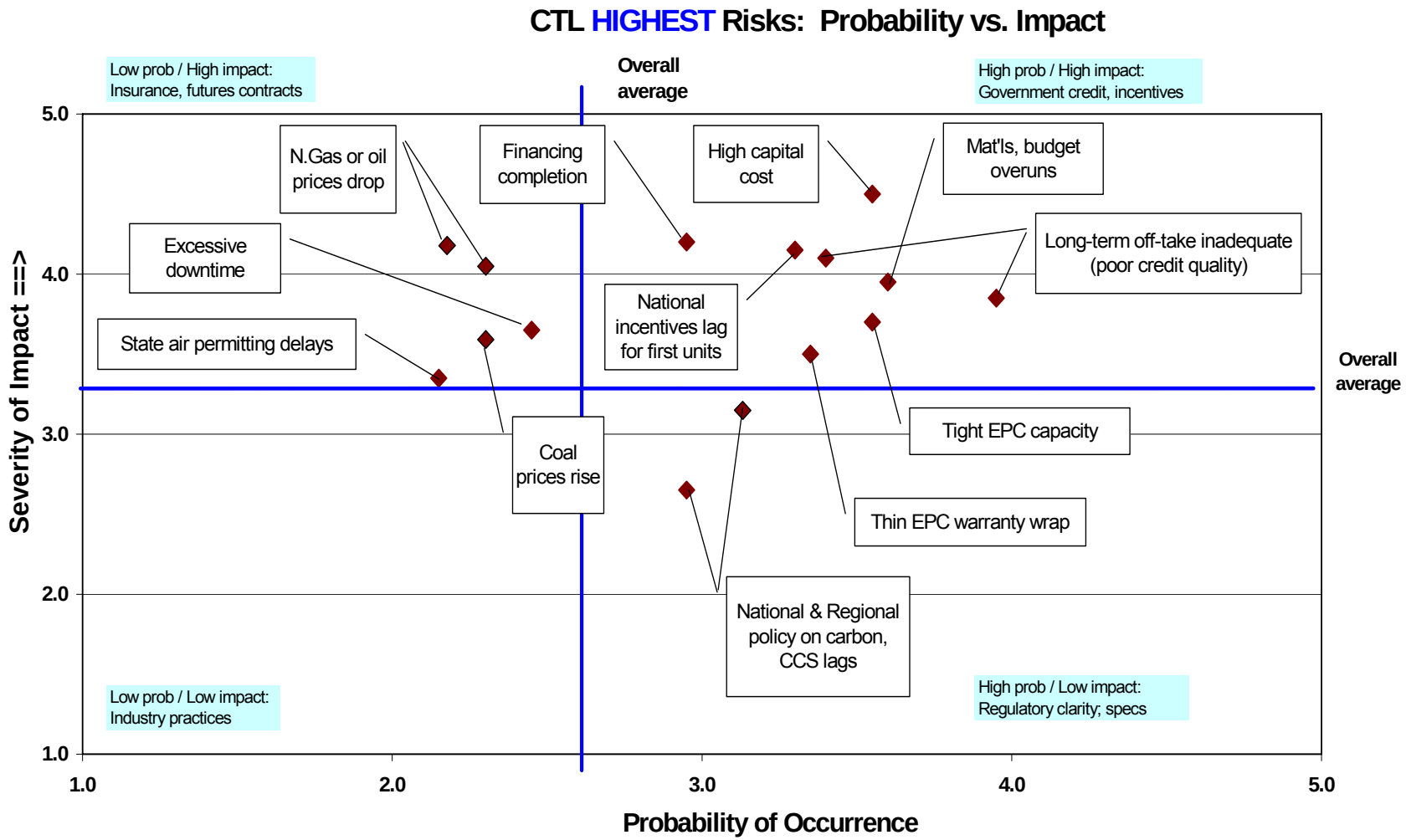
Plot of Market Risk Ratings

The inadequacy of off-take agreements creates a clear market risk that hinders financing.

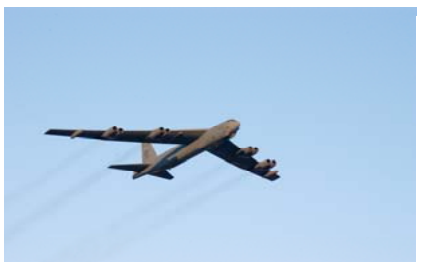


RECAP: Highest Risk Ratings

High capital costs, inadequacy of off-take agreements, lack of EPC wrap (warranties), confusion on carbon policy all hinder financing.



Reference Plants



Technology Overview

- Coal gasification with co-production of transportation fuels is known as “coal-to-liquids (CTL)”. CTL plants integrate coal gasification with Fischer-Tropsch (FT) units.
- Coal gasification process can be linked with several other unit operations in co-production plants, including:
  - Electricity generation (IGCC plants)
  - Synthetic natural gas (SNG plants)
  - Ammonia / urea
  - Methanol
  - Hydrogen
  - Steam production
- Coal gasification offers easier and less costly capture and compression of CO_2, facilitating CO_2 sales and sequestration.
- FT fuels can be at least carbon neutral compared with oil-based fuels (if CO_2 from gasifiers and FT units is used or sequestered).

Reference Plant Financing Assumptions

- Capital structure: 30% equity – 70% debt
- Interest rate: 8% annual
- Amortization: 15 years with mortgage-style debt amortization. Debt matches off-take agreement with creditworthy counterparty. Depreciation over 15 – 20 years.
- Reserves: Debt service reserves capitalized at 50% of maximum annual debt service.
- Interest capitalization: Capitalized during construction and 1st year of operation (during ramp-up).
- Marginal income tax rate: 40% (Federal and state)
- Tax loss benefits: Utilized currently
- Other costs:
  - Development costs: 2.5% of EPC
  - Financial closing costs: $50 million.
- After-tax equity internal rate of return range: 17%–19%

Financing Assumptions *(cont'd)*

- **"Project finance"** refers to a wide range of financing structures that have one feature in common: The financing is "off balance sheet," i.e., not primarily dependent on the credit support of the sponsors or the value of the physical assets involved.
- **Weighted average cost of capital (WACC)** achieved under financing assumptions in the high IRR reference case =

$$(70\% * 8\%) * (1\text{-}40\%) + (30\% * 19\%) = 9.1\%$$

- Comparison: Weighted average cost of capital for selected oil and gas companies = 10.1% (see table):
- Risk-adjusted "hurdle rates" may be higher than WACC in unconventional investments (e.g., first-of-a-kind commercial plants).

Company Name	Post Tax WACC*
Amerada Hess	9.2%
Anadarko	10.4%
Apache	10.6%
Burlington Resources	10.0%
Chevron	10.7%
Conoco Phillips	10.4%
Exxon Mobil	11.4%
Kerr-McGee	10.3%
Marathon	10.0%
Murphy	11.2%
Occidental	5.8%
Unocal	10.4%
AVERAGE	**10.1%**

* Source: Texas comptroller of Public Accounts. 2005.

Reference Case Results *(Bituminous Plant)*

SCULLY CAPITAL

EXHIBIT 1: SOURCE AND USES OF FUNDS ($000)
PROJECT: Coal Gasification with Co-Production Plant Study
Scenario Number: 1 - Reference Case: 30,000 bpd blant w/ Bituminous coal

USES		SOURCES	
Facility Costs		**Gross Funding Requirements**	$ 3,269,062
Solids Handling	$ 166,616		
Air Seperation Unit	261,673		
Gasification	470,533	Equity	980,719
F-T Liquids Area + refining	369,650	Equity %	30.0%
Power Block	296,650		
Gas cleanup/polishing	300,197	Debt	2,288,343
Carbon Sequestration Equipment	-	Debt %	70.0%
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	Tranche A	2,288,343
			70%
Financing Costs		Tranche B	0
			0%
Development Costs	54,248		
Closing Costs	50,000		
Debt Service Reserve Fund	129,840	Tranche C	-
Capitalized Interest	423,059		0%
Subtotal - Financing Costs	657,147		
Gross Funding Requirements	**$ 3,269,062**	**Total Funds Drawn**	**$ 3,269,062**

- Output pricing (+/– 30%)
  - FT fuel: $72.83 per barrel
  - (Crude equivalent: $56.02 per barrel)
- Pre-tax minimum DSCR is 1.67x (debt service)
- Average DSCR is 2.16x
- Internal Rate of Return (IRR) = 19%, after tax
- Cost of debt = 8%
- D/E ratio = 70:30

Alternative Plant Cost, Outputs

Type of Coal Co-Production Plant	Bituminous Coal Reference Plant	Alternative Plant	% 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: Diesel-Equivalent FT	32,502	30,001	-8%
Electricity Production			
Gross (MWe)	725	1045	31%
Parasitic Load	468	455	-3%
Net (MWe)	257	590	56%
Carbon Dioxide That Can Be Captured (in tons/day)			
Input Carbon			
Carbon That Can Be Captured	6,763	7,083	5%
In Fuel	3,918	3,616	-8%
In Stack Gas	860	1,823	53%
Total	11,541	12,522	8%
Carbon That Can Be 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%	

- Same primary outputs, but 2x power & less fuel
- ~30,000 bpd of diesel-equivalent fuel: 75% FT fuels; 34% naphtha @ $30/bbl
- Net power: 590 MWe (versus 257 MWe)
- Plant cost: Overnight capital = $2.88B; Total = $3.60B
- CO_2 compression and sequestration add 3%–5% ($130 mm) to capital cost + 9% to operating cost